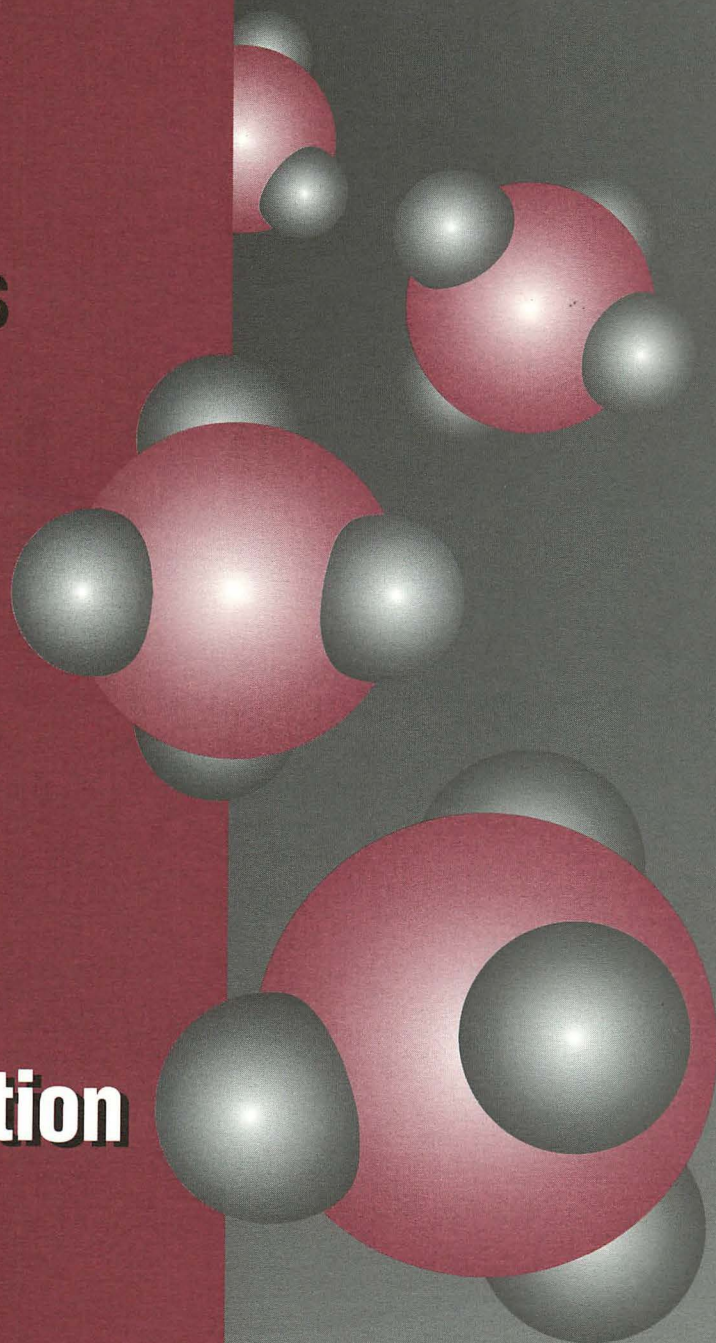


**The
Potential for
Natural Gas**

**in the
United States**

**Model Documentation
and Results**

December 1992
National Petroleum Council



On the Cover: Graphic Representation of Methane Molecules, CH₄,
the Primary Chemical Compound in Natural Gas.

NATIONAL PETROLEUM COUNCIL

1625 K Street, N.W., Washington, D.C. 20006 (202) 393-6100

December 17, 1992

The Honorable
James D. Watkins
Secretary of Energy
Washington, D.C. 20585

Dear Mr. Secretary:

On behalf of the members of the National Petroleum Council, I am pleased to transmit to you herewith the Council's report entitled *The Potential for Natural Gas in the United States*. This report was prepared in response to your request and was unanimously approved by the membership at their meeting today.

Natural gas has the potential to make a significantly larger contribution both to this nation's energy supply and its environmental goals. Achieving that potential will take a commitment of innovation, leadership, and resources by the industry to overcome challenges that arise from its current operations, its history, and its regulation. The National Petroleum Council concludes that industry has already initiated actions in support of that commitment and believes the industry is prepared to continue those activities.

This study finds that natural gas is uniquely positioned to take on this expanded role for three reasons:

1. Natural gas can be produced and delivered in volumes sufficient to meet expanding market needs at competitive prices.
2. Natural gas is a clean-burning fuel, and can be used in a variety of applications to satisfy environmental requirements.
3. Natural gas is a secure, primarily domestic source of energy that can help improve the national balance of foreign trade.

In addition, much of the groundwork necessary to develop a more competitive and customer-oriented industry has already been laid.

Perceptions of natural gas that arise from its heavily regulated past represent the greatest challenge to be overcome by the industry. In particular, the industry must pay more attention to meeting customer needs through greater efficiency and more competitive services. Efforts like this study to define the problem and outline its solution, have become critical to realization of natural gas' potential.

The National Petroleum Council sincerely hopes the enclosed report will be of value to the Department of Energy, and government at all levels, as natural gas and the natural gas industry realize their potential.

Respectfully submitted,



Ray L. Hunt
Chairman

Enclosure

An Advisory Committee to the Secretary of Energy

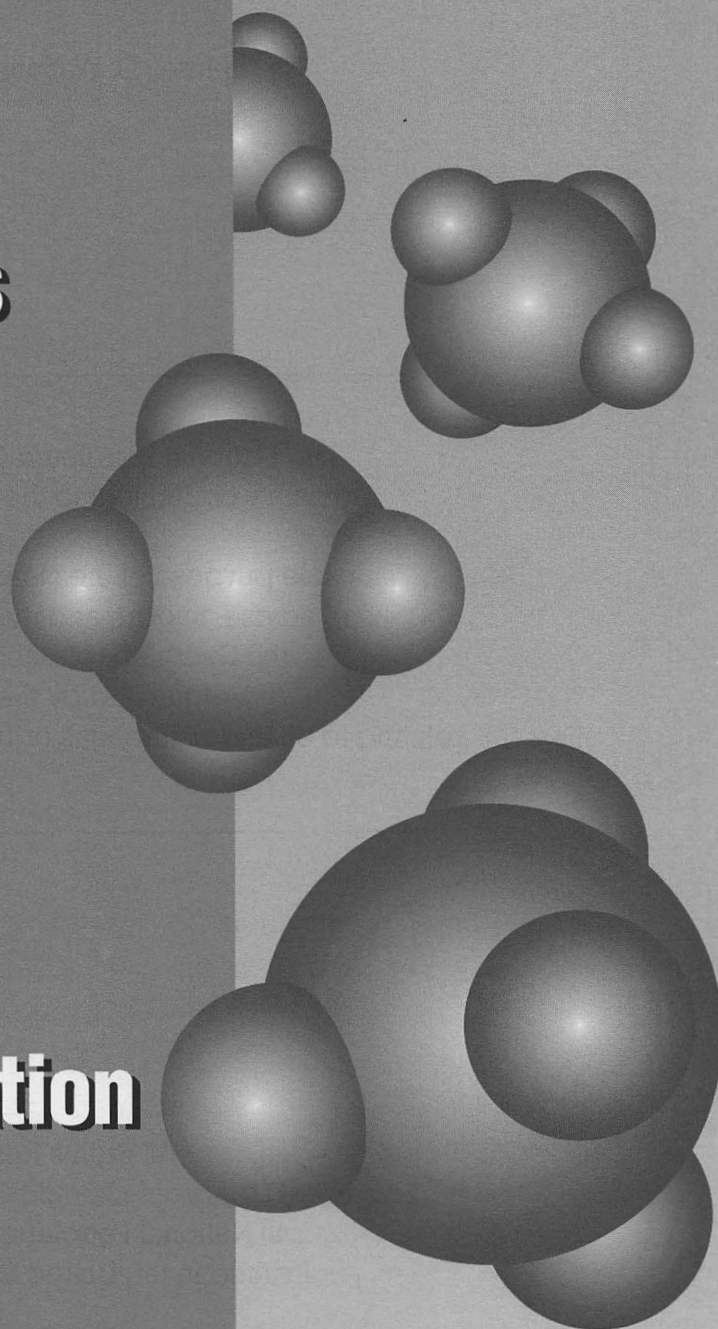
The Potential for Natural Gas

in the United States

Model Documentation and Results

**December 1992
National Petroleum Council**

**Committee on Natural Gas
Frank H. Richardson, Chairman**



NATIONAL PETROLEUM COUNCIL

Ray L. Hunt, *Chairman*
Kenneth T. Derr, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U.S. DEPARTMENT OF ENERGY

James D. Watkins, *Secretary*

The National Petroleum Council is a federal
advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council
is to advise, inform, and make recommendations
to the Secretary of Energy on any matter
requested by the Secretary
relating to oil and natural gas or to the oil and gas industries.

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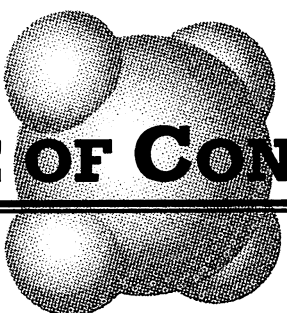


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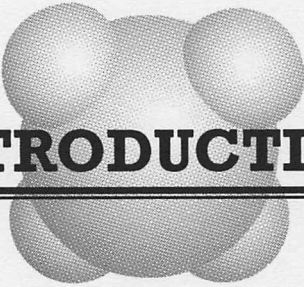
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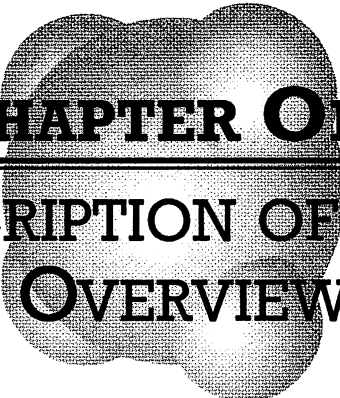


INTRODUCTION

As discussed in Volume I of this report, the NPC study used two scenarios for analyzing potential future energy needs and the natural gas supply/demand balance for the United States. *The NPC did not attempt to develop a forecast of the future and the projections that are presented in this report should not be interpreted as such.* The purpose of the modeling effort was to provide a consistent framework for analyzing the supply potential, market opportunities, and transportation requirements under varying energy demand options, and to assess the sensitivity of the results to the uncertainties in the assumptions. The energy demand options were derived to be consistent with other assumptions concerning economic growth rates, consumption patterns, efficiency trends, availability of alternative fuels, etc. The two scenarios were selected to be sufficiently different so as to provide independent alternative views of future energy requirements. *Both scenarios are believed to be realistic and neither one is considered to be a "most likely" projection of future requirements.*

These two scenarios were modeled by DRI using their Macroeconomic and World Oil Models. DRI's models are described in Chapter Two and the assumptions specified by the NPC are contained in Chapter Three. Chapter Four contains the detailed output from DRI for each of the scenarios.

The NPC used the EEA Energy Overview Model to determine the sensitivity of the modeling results to various assumptions and as a guide to the selection of appropriate parameter values. Chapter One provides a description of EEA's Model. The model was run both in its integrated form and using individual portions of the model on a stand-alone basis. Chapter Three documents the NPC assumptions that drove the EEA modeling results, and outputs from the model runs are included as Chapter Five. Analysis of the key model results are included in Volumes II through IV along with discussion of the assumptions used.



CHAPTER ONE

DESCRIPTION OF EEA ENERGY OVERVIEW MODEL

1. INTRODUCTION

1.1 The Energy Overview Model

The Energy Overview Model is a forecasting model and analytical tool designed to simulate natural gas supply, demand and prices in the U.S. and Canadian energy markets. Since the original model release in 1981, more than 20 man-years of effort have been put into development of the model's characterization of natural gas supply, the U.S. and Canadian pipeline system, and end-use demand. Since 1985, much of this effort has focused on reflecting the far-reaching institutional changes introduced in the U.S. gas market by FERC Orders 436, 500, and 636 and the other regulatory and market developments.

Important factors in model simulations include the spot market trading of natural gas, the dual role of pipelines as gas merchants and transporters, and the increased range of supply options available to gas distributors and end-users. A central aspect of the model's design is the representation of how the decisions of producers, pipelines, distributors and end-users interact in this new institutional structure. Because of its explicit treatment of the evolving market structure, the model can be used to provide important insights and analyses of a wide range of issues facing the industry including:

- The pace of drilling activity and reserve additions by region
- Regional deliverability levels
- Regional market prices
- Level of demand for natural gas by region and sector
- Patterns in interregional gas flows
- Need for new gas pipeline capacity
- Changes in monthly patterns of gas demand and prices

Because it simulates both the structure of the North American gas market and regional trends for energy consumption and gas supply costs, the Energy Overview Model has a wide range of applications in gas market analysis. Some of these applications include:

Market Scenario Development: The model is used by a growing community of producers, pipelines, and distributors to develop market scenarios for corporate planning purposes. An important characteristic of the model in these applications is the wide-range of user inputs available for tailoring model scenarios to reflect the planning outlooks of individual users.

Sensitivity and Impact Analysis: The model can be used to test the sensitivity of market forecasts to factors such as: the uncertainty in future energy prices; scenarios for economic growth; institutional changes; environmental

regulations; and assumptions regarding the potential U.S. hydrocarbon resource base and cost of exploration and development. In addition, its ability to simulate institutional change allows the model to reflect market impacts of such factors as contract carriage and the reform of gas purchase contracts through negotiation or regulatory action.

End-Use Market Analysis: Model forecasts for wellhead prices, gas supply trends, and burnertip prices can be used to provide inputs for end-use market analyses by gas pipelines and distributors.

Gas Acquisition and Facilities Planning: The model forecasts the availability and cost of new gas reserves by region and interregional gas flows and thus can be used in planning future gas acquisitions and facilities.

Technology Evaluation: Because gas field development costs and deliverability are mod-

eled in detail, the impact on gas costs and markets of technologies for gas production can be estimated.

Drilling Market Analysis: Forecasts of drilling activity from the model can be used in market analyses of drilling and related services and products.

Policy Analysis: The model has wide application in the analysis of government regulation or tax policy on oil and gas supply, upstream environmental regulations and end-use emissions limits.

1.2 Energy Overview Model Operating Modes

Three operating modes are available for the Energy Overview Model. Selection of an operating mode depends on the intended application. As summarized in Figure 1-1, the three options are:

OPERATING MODE	MODEL COMPONENTS	PURPOSE	MAJOR OUTPUTS
MODE 1: Simulation – National Gas Supply / Demand Balance	• Supply Model • Pipeline Network Model • T&D Rates Model • Demand Models	To solve for gas demand, gas prices and drilling activity over time given inputs of oil prices, regulatory scenario, alternative fuel prices, economic growth, etc.	<i>BY YEAR OR RUN PERIOD</i> • Gas demand by 10 U.S. and seven Canadian regions by end-use sectors • New wellhead gas prices • Delivered gas prices by region and end-use sectors • Drilling activity, reserve additions and production by supply region • Interregional gas flows and new pipeline capacity
MODE 2: Simulation – Stand-Alone With User-Specified Gas Demand	• Supply Model • Pipeline Network Model • T&D Rates Model	To solve for gas prices and drilling activity over time given input of gas demand, oil prices, regulatory scenario, etc.	<i>BY YEAR OR RUN PERIOD</i> • New wellhead gas prices • Delivered gas prices by 10 U.S. and seven Canadian regions and end-use by sectors • Drilling activity, reserve additions and production by supply region • Interregional gas flows and new pipeline capacity
MODE 3: Long Run Gas Supply Curve Generator	• Supply Model	To describe resource base assumptions of model in concise form	• Natural gas "supply curves" and tables

**Figure 1-1. Summary of the
Three Operating Modes for the Energy Overview Model**

Mode 1: Simulation Over Time - Equilibrating Mode with Gas Supply/Demand Balance

Mode 2: Simulation Over Time - Stand-alone Mode with User-specified Gas Demand

Mode 3: Long Run Gas Supply Curve Generator.

The Simulation Modes

The first two operating modes of the Energy Overview Model are referred to as Simulation Modes because they simulate the evolution of the gas market over a period of years. Mode 1, the Equilibrating Mode with Supply/Demand Balance, consists of the Hydrocarbon Supply Model, the Pipeline Network Model, the T&D Rates Model and the End-use Demand Models linked in an equilibrium framework for natural gas supply and demand. The Hydrocarbon Supply Model simulates investment decision-making in the oil and gas industry to determine the level and location of exploratory and development drilling activity in each model period. The Pipeline Network and T&D Rates Models simulate gas transportation flows on the U.S. pipeline system, supply acquisition decisions by gas pipelines and distributors, and costs for transmission and distribution to forecast burnertip prices by region and sector. The third component, the End-use Demand Models, then determines the level of gas demand given gas prices, alternative fuel prices and the user's economic growth scenario.

When the EOM is run in Mode 1, the model solves for the equilibrium natural gas demand levels and gas prices given user-specified inputs of the scenario. The major gas supply outputs of this mode of the model are the levels of exploratory drilling, development drilling, reserve additions, production, and the spot and long-term contract prices for natural gas in each year. The major gas demand outputs include the level of gas and non-gas energy demands and natural gas burnertip prices by demand region and sector (i.e., residential, commercial, industrial, and electric utility).

Mode 2, the Stand-alone Simulation mode, is operationally similar to the first mode except that gas demand is specified by the user and the model solves for natural gas supply and prices alone. Because gas demand is specified outside of the model, this mode does not utilize the End-use Demand Models. Mode 2 is used to answer the specific "what if" questions

under an exogenous planning scenario of gas demand in solving for the level of reserve additions and new gas supply prices, given certain assumptions such as oil prices, interest rates, and size of the resource base. Outputs of Mode 2 (Stand-alone Simulation) are identical to Mode 1 (Equilibrium Simulation) with the exception that output related to the demand models is excluded.

Curve Generating Mode

Mode 3, which is a special run-mode for the Hydrocarbon Supply Model, is the Long Run Gas Supply Curve Generator. The purpose of this mode is to give users a better understanding of the resource base assumption selected for the supply model in the concise form offered by a long-run "supply curve." This mode is used to show how the oil and gas resource base is distributed with regard to the cost of discovery, development and production. In this mode a cost/quantity "long run supply curve" for natural gas is created. These cost/quantity curves can be aggregated in any desired combination of region and depth as well as by total Lower-48 and Canada. These curves represent the quantities of natural gas that could be found and produced at various wellhead prices irrespective of when discovery and production might take place. In this sense, the curves are described as "time-dimensionless."

1.3 General Methodology For EOM

The Energy Overview Model uses a combination of process engineering, statistical and behavioral relationships to perform annual and monthly simulations of natural gas markets. Most of the components of the Energy Overview Model are "process engineering" models in which:

- 1) the physical processes of energy production, conversion or consumption are represented along with their attendant costs, and
- 2) decisions are simulated using standard business techniques such as discounted cashflow analysis.

This structure helps make model inputs and logic very transparent to the user and allows important assumptions to be easily changed for purposes of sensitivity analysis.

Hydrocarbon Supply Model

The gas supply component of the EOM, the Hydrocarbon Supply Model is a process engineering model with a very detailed representation of potential gas resources and the technologies with which those resources can be proven and produced. The degree and timing by which resources are proven and produced are determined in the model through discounted cashflow analyses of alternative investment options and behavioral assumptions in the form of inertial and cashflow constraints and the logic for setting producers' market expectations (e.g., future gas prices).

Industrial and Electric Utility Demand Models

The industrial and electric utility demand models also have a process engineering structure in that energy demand is disaggregated into functional use categories (e.g., boilers, cement kilns), each of which has specific fuel switching characteristics, environmental regulations and costs. Fuel use decisions for new units (e.g., a coal boiler *versus* combined cycle gas unit in electric utilities) are typically made on the basis of minimizing total life-cycle capital and operating costs. Short-term fuel switching decisions for existing units are made on the basis of fuel firing capability, operating cost differentials and fuel prices.

Residential and Commercial Demand Models

The residential and commercial demand models in the EOM are econometric in form. EEA has developed a process-engineering model to address energy issues in the residential and commercial sector. However, since residential/commercial natural gas trends will shift slowly relative to other sectors of the economy, only a simplified, reduced-form econometric version of the residential/commercial demand model is incorporated into the Energy Overview Model.

Pipeline Network Model

Natural gas pipelines are represented in the EOM by the Pipeline Network Model, which characterizes pipeline routes, capacities and transmission costs linking approximately 60 receipt and delivery points in the U.S. and Canada. The Pipeline Network Model uses a

nonlinear optimization algorithm to determine the pattern of gas flows that minimizes delivered gas prices at each node. These gas flows are limited by capacity and may be made subject to contract minimums. A unique feature of the EEA Pipeline Network Model is its simulation of pipeline capacity expansion decisions. The user specifies potential pipeline projects including capital costs, fuel losses and rate treatment and the model decides when conditions are right for additional capacity to be added. The results of the Pipeline Network Model are presented in the form of tables and

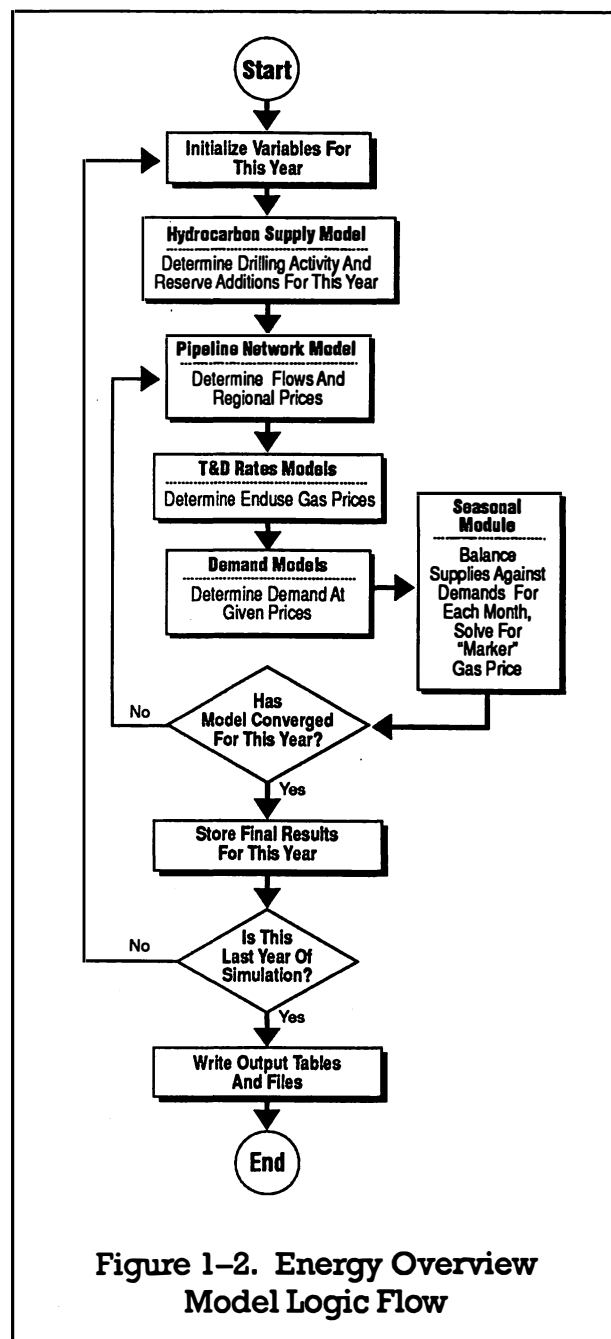


Figure 1-2. Energy Overview Model Logic Flow

maps showing pipeline capacity, flows, capacity utilization rates on each corridor along with gas prices at each node.

Solution Procedure

The overall logic flow of the EOM operating in the Equilibrating Mode is illustrated in Figure 1-2. The simulation starts with guesses for current year gas demands and the "marker gas price", i.e., the average annual Gulf Coast spot price. The Hydrocarbon Supply Model then is executed to determine drilling activity and reserve additions for that year. Together with reserves carried forward from previous years, this establishes total reserves and, thus, available deliverability from the US and Canada.

The Gas Pipeline Network Model then is solved to determine flows and spot prices at each node given deliverability in each supply region, the initial guesses for demand and the

marker gas price. Then, the T&D Rates Model takes all gas volumes and prices and calculates end-use gas prices.

The next step is to use these end-use gas prices in the demand models to update the guess for natural gas demands (and other fuels). If certain volumes are within tolerances, the model has "converged" for that year, and the model proceeds to the next year. If there is no convergence, the revised demand levels are put back into the Pipeline Network and T&D Rates Models to determine a new set of end-use gas prices, the Demand Models are run again with these new gas prices, and convergence is checked once more.

Part of this iteration process toward reaching convergence for the year is the operation of the Seasonal Module, which breaks out demand and supplies by month. The Seasonal Module determines storage patterns, the degree of monthly fuel switching needed to balance the market, the feasible wellhead capacity utilization rate and monthly prices in the Gulf Coast spot market. The monthly prices coming out of the Seasonal Module are averaged into an annual average price which is the basis for determining regional spot and long-term contract prices in the EOM.

1.4 User Options For Equilibrating Mode

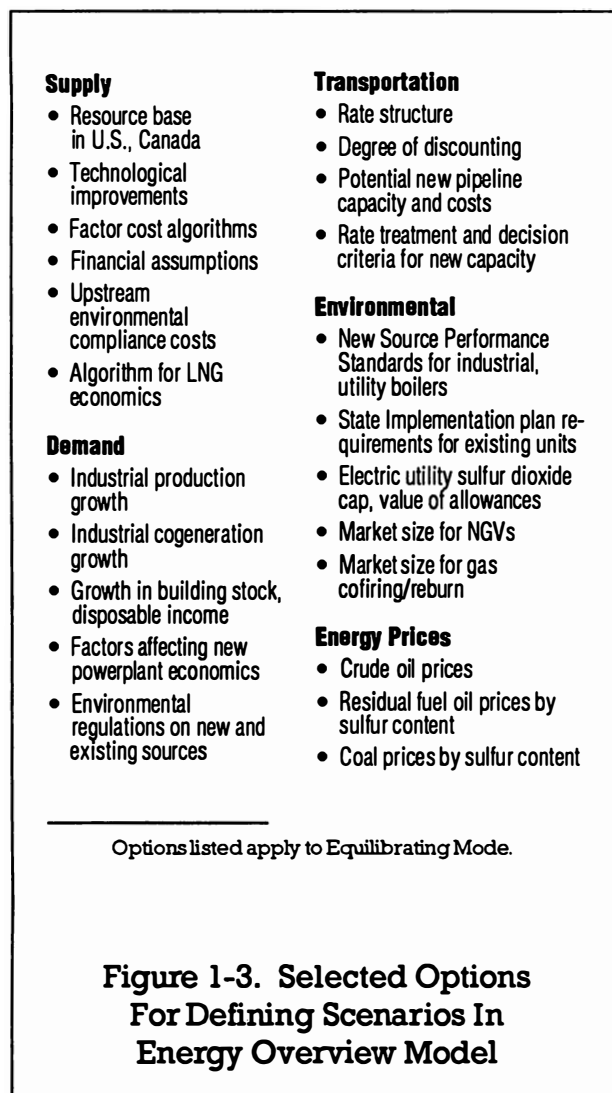
Most uses of the Energy Overview Model have been in the Equilibrating Mode in which natural gas supplies, demands and prices are solved for simultaneously. The key user options available for constructing scenarios in the equilibrating mode are shown in Figure 1-3.

1.5 Outputs Of Equilibrating Mode

The major outputs from the model are shown in Figure 1-4. All outputs are available on paper. Additionally, many of the outputs are available in spreadsheet format for personal computers. The spreadsheet outputs may be used to create graphs or to compile data from several runs.

1.6 Organization Of Documentation

Section 2 of this volume summarizes the key features of the Hydrocarbon Supply Model. The next chapter deals with the three demand models contained in the EOM: the industrial



demand model, the electric utility model and the residential/commercial demand models. Section 4 summarizes the representation of natural gas transportation and distribution. Finally, Section 5 reviews the EOM's methodology for solving for prices and demand on a monthly and annual basis.

An additional volume entitled *Guide to the Hydrocarbon Supply Model* contains additional information on the methodology and data on the gas supply component of the Energy Overview Model and is available from the NPC or EEA.

2. HYDROCARBON SUPPLY MODEL

2.1 Introduction

The Hydrocarbon Supply Model was developed by Energy and Environmental Analysis, Inc. (EEA) for the Division of Strategic Planning and Analysis of the Gas Research Institute in Washington, D.C. The Hydrocarbon Supply

Model is a computer-based analytical framework designed for the simulation, forecasting and analysis of natural gas, crude oil and natural gas liquids supply and cost trends in the United States and Canada. It operates as the gas supply component of EEA's Energy Overview Model.

Several factors set the Hydrocarbon Supply Model apart from other oil and gas supply models. The most important of these distinguishing characteristics are the:

- Highly disaggregated characterization of the undiscovered resource base
- Detailed treatment of the costs for exploration, development and production of oil and gas reserves,
- Explicit simulation of decisionmaking by oil and gas producers and gas pipeline companies,
- Representation of the economics of existing gas wells and how they could be im-

	On Paper	Spreadsheet Form*		On Paper	Spreadsheet Form*
Supply			New pipeline construction by corridor	X	X
Drilling activity by region	X	X	Pipeline receipts by pipeline group, type of service	X	X
Reserve additions of gas, oil, NGLs by region	X	X	Pipeline receipts by demand region destination, type of service	X	X
Gas, oil, NGL production by region...	X	X	Pipeline revenues by pipeline group, type of service.....	X	X
Gas, oil, NGL reserves by region.....	X	X	Pipeline margins by pipeline group, type of service.....	X	X
Producers' cashflow accounts	X	X			
Producers' rate of return	X	X	Gas Prices		
Demand			Wellhead gas prices by supply region	X	
Demand for gas and other fuels by sector and region.....	X	X	Citygate gas prices	X	X
New powerplants by fuel type and region	X	X	Enduse gas prices by region, type of service	X	X
Powerplants inventory, capacity utilization by fuel type and region.....	X		Monthly Gulf Coast spot gas prices ..	X	X
Monthly demand/supply balance	X		Other Energy Prices		
Transportation			Wellhead crude oil prices by region..	X	
Flows along interregional pipeline corridors.....	X	X	Coal and oil product prices by region and sector	X	X

* Spreadsheet output in Lotus123 for PC or MS Excel for Macintosh.

Figure 1-4. Selected Available Outputs From Energy Overview Model

pacted by changing prices, taxes, royalties or environmental regulations,

- Representation of technological advances in exploration, development and cost reductions,
- Ease in incorporating uncertainty into model scenarios, and
- Linkage to EEA's pipeline and demand models so that full gas market simulations can be made.

2.2 Scope Of Hydrocarbon Supply Model

The model covers the Lower 48 United States, Alaska and Canada. The Lower-48 States are broken down into thirteen onshore regions and four offshore regions (Figure 2-1). The onshore regions in the model are divided into four depth intervals: 0-5,000 feet, 5-10,000 feet, 10-15,000 feet and below 15,000 feet. The offshore regions are divided into one, two or four water depths. Each depth interval within each region is modeled with a unique resource base, exploratory find rates, drilling costs and well production profiles.

Canada is divided into five regions which are further divided into intervals representing drilling depths or subregional areas. (Figure 2-2).

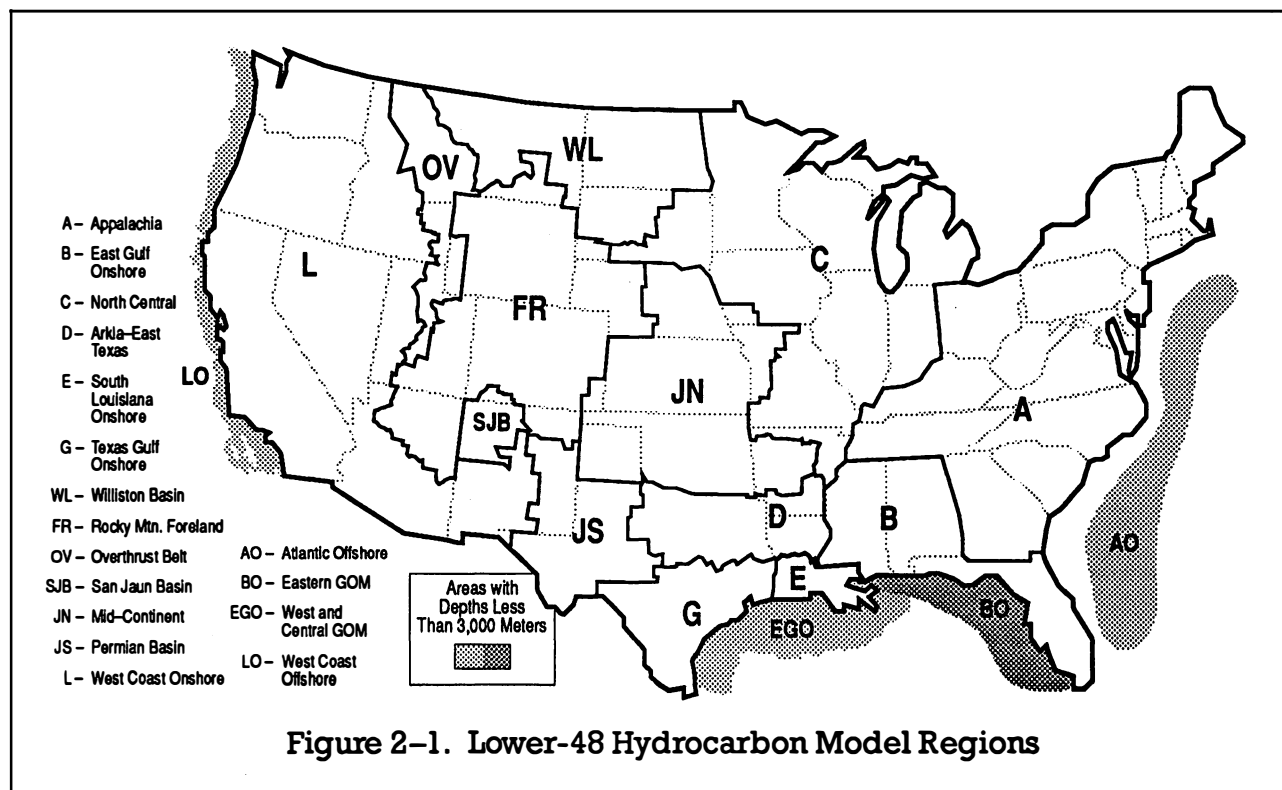
Although the major focus of the Hydrocarbon Supply Model is on natural gas, the model also covers the exploration, development and production of crude oil because, generally, exploration activity can be directed only at oil-prone or gas-prone regions, not at oil or gas specifically. As a result, exploration in a gas-prone area carries with it some probability of finding oil and vice versa. Therefore, oil and gas fields must be treated together in using historical data to develop find-rate equations.

2.3 Resource Base And Discovery Process

Resources in the Hydrocarbon Supply Model are divided into three general categories: new field, field appreciation, and nonconventionals. Characterization of each category is discussed below.

New Fields

The key feature of any exploration and development model is its representation of how exploratory activity leads to the discovery of additional reserves. This discovery process usually is modeled through "find-rate equations". A major consideration in developing the representation of the discovery process for the Hydrocarbon Model was that the approach be



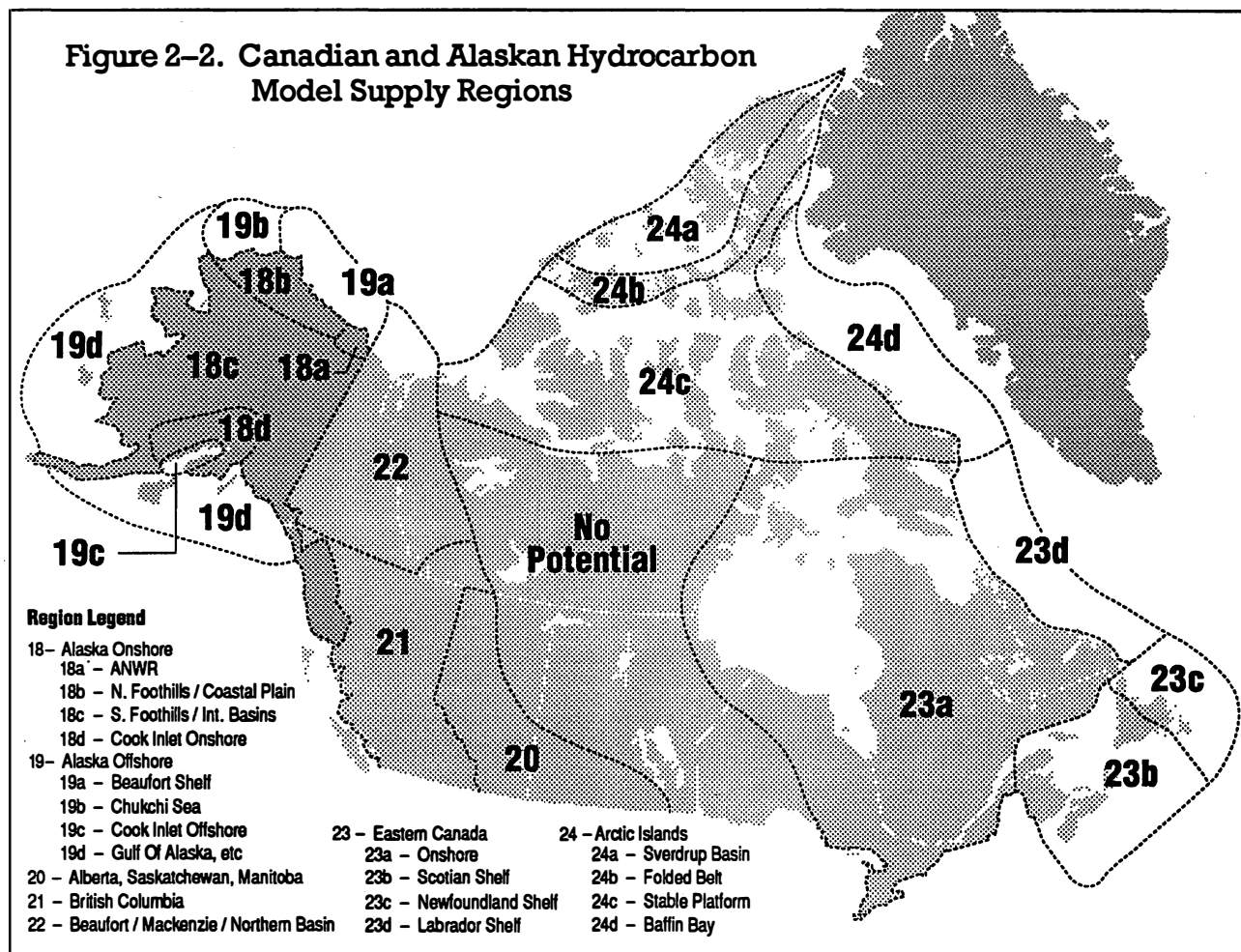
as accurate as possible and that it be able to reflect accurately the cost of finding and developing oil and gas reserves. To achieve this, EEA decided that the regions in the model should be broken out into depth intervals and that the find-rate equations should estimate the distribution of field sizes found in an increment of exploratory drilling. The reason for distinguishing among depth intervals is to reflect more accurately the cost of drilling wells and the differences in resource depletion among shallow and deeper horizons. Field sizes are characterized in the find-rate equations to allow for an accurate treatment of development costs and an explicit modeling of the economic decision of whether to develop a field once it is found. Within the model, each field size found in an increment of exploratory wells is subjected to an economic analysis to determine whether it will be profitable to develop. Only profitable finds are developed and booked as proven reserves.

The basis for the find-rate methodology used in the Hydrocarbon Model is work done by J. J.

Arps and T. G. Roberts in 1958 and the subsequent elaboration and modifications to the work by Larry Drew, David Root, J. H. Schuenmeyer and others at the U.S. Geological Survey (USGS). The fundamental theory behind the find-rate methodology of these authors is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The methodology used in the Hydrocarbon Model starts from this same basis, but changes the mathematical formulation to match more closely the observed discovery pattern of mid- to small- size fields.

The find-rate equations are used in the model to predict the number of fields of a certain size that will be discovered after a given number of exploratory wells have been drilled. There are separate equations for each field-size class (e.g., size class 9 is between 0.76 and 1.52 million barrels of oil equivalent or 4.3 to 8.7 bcf of gas equivalent) within each depth interval,

Figure 2-2. Canadian and Alaskan Hydrocarbon Model Supply Regions



within each region. The Lower-48 portion of the model has 17 regions, up to 4 depth intervals and 20 field sizes for a total of approximately 1,060 separate find-rate equations.

It is important to keep in mind that the result of the find-rate equations is a distribution of fields discovered for an increment of drilling somewhere along the discovery process. Because the large fields are more likely to be found relatively early, the distribution in the first stages of the exploration process contains a relatively high number of large fields along with medium- and small- size fields while, in the later stages of the process, the distribution contains only medium- and small- size fields. The results of the find-rate equations represent the expected value of field discoveries per size class. This is conceptually similar to averaging the results of a large number of Monte Carlo simulations in which the probability of discovering a field is related to its areal extent.

For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields and low permeability gas fields based on the expected occurrence of each type of field within the region and depth interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing specific percentages each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are either oil, sweet nonassociated gas or sour nonassociated gas.

Old Field Appreciation

Reserves in a field are proved over a period of several years. For this reason, only a portion of the gas reserves in fields found by a new field drilling increment undertaken in a year will be proved and available for production in that year. The remaining reserves will be proved in later years. The Hydrocarbon Supply Model maintains inventories of potential resources that can be proved from already discovered fields. Following the designations used by the Potential Gas Committee, these resources are commonly referred to as "probables."

As the model simulation proceeds, these "probables" inventories are drawn down as the resources are proved. At the same time, the inventories of probables are increased from future year appreciation to new fields discov-

ered during the model simulation. The methodology by which these probables inventories are proved in the model is partially time-dependent, in that "growth curves" determine the maximum rate at which probables can be proved each year after a field's discovery. The "growth curves" for the probables inventories at the start of model simulation, vary by region and field type. Other growth curves, which vary by field type and field size class, determine the rate at which reserves are proved from fields whose discovery the model simulates.

The resource cost of the gas in the probables inventories is lower than the resource cost of new fields because the new field exploratory costs are considered sunk. Because gas is added to these inventories at different times for various depths and regions, there is a distribution of prices for old field gas that can be proved in any given period. Each period, the model evaluates whether or not to prove each element in the probables inventory made eligible by the "growth curves". The producer's expected oil and gas prices are compared against the resource cost of the potential reserves. All elements meeting this criterion have a rate of return at least equal to the producer's minimum ROR and are proved in the period, unless capital constraints are binding. In that case, only a portion of each element is proved. Any of the probable resources not proved in the current period are added to the next period's inventory and will be re-evaluated in that later period.

Enhanced Recovery Module

The Enhanced Recovery Module, or ERM, covers that portion of the resource base which falls outside the scope of the "conventional" oil and gas field discovery process dealt with elsewhere in the model. For instance, the ERM includes coalbed methane, Devonian shale gas and tight gas. The ERM also may be used to characterize the application of technologies or development approaches such as infill drilling or thermal EOR, which increase recovery in conventional reservoirs.

The ERM is organized by "cells", which represent resources in a specific geographic area. A cell can represent any size of area ranging from the entire region/depth interval to a single formation in a few townships of a basin. Up to three different technology cases can be specified for each cell, along with assumptions

about how the market share among the technologies will change over time.

A total of 154 ERM cells have been assembled to evaluate nonconventional gas resources for NPC. Devonian Shale resources are modeled for the Appalachian and Michigan Basins. The 30 Appalachian Basin cells represent Devonian Shale in West Virginia, Kentucky, Virginia, Ohio, Pennsylvania, and New York. The 5 Michigan Basin cells represent gas resources in the Devonian Antrim Shale, which has recently been the target of a considerable amount of drilling.

Lower-48 coalbed methane is represented by 54 cells for the Appalachian, Warrior, San Juan, Piceance, Raton, and "Miscellaneous" Rocky Mountain Basins. While the great majority of historical coalbed activity has occurred in the San Juan Fruitland and the Warrior Basins, a large amount of recoverable gas exists in the other included basins as well. The inclusion of "Miscellaneous Basins" with the Raton Basin is intended to capture areas such as the Uinta, Green River, and Powder River Basins which are currently poorly understood but may eventually be productive. EEA has also modeled the coalbed methane resources of Alberta with 10 cells.

Lower-48 tight gas is represented by 47 cells covering Appalachia, East Texas, Arkla, the Texas Gulf Coast, the Mid-Continent, and the Rockies. Each Lower-48 tight gas cell represents the resources in a specific basin and formation. This representation differs from the coalbed and shale cells which generally represent specific areas within a basin of the same formation. Alberta Basin tight gas is represented by 5 cells.

Low-BTU gas along the Moxa Arch in the Green River Basin of Wyoming is also represented in the model. These cells primarily represent a single massive reservoir containing 170 Tcf of raw gas. The gas mostly consists of carbon dioxide but contains up to 22 percent methane.

Each cell is evaluated in the model using the same discounted cashflow analysis used for new and old field investments. The ERM cells also are subject to the inertial and cashflow constraints affecting the other types of investment options in the model. The model reports total reserve additions, production and dollars invested for each type of ERM cell (e.g., coalbed methane) within a region. Detailed information also is available on each cell in diagnostic tables.

Existing Reserves

The model maintains inventories of reserves proved before the start of model simulation and tracks the cost of producing those reserves over time. It is possible to simulate cases in which those costs change due to new environmental regulations. The model calculates how the abandonment point of existing gas wells changes due to the higher costs and computes reserves and deliverability lost for nonassociated gas.

2.4 Costs

The model contains a wide variety of cost data for wells, well stimulation, lease equipment, offshore production platforms, well operation, and gas processing.

Well Cost

Onshore well costs are affected by the region in which they are drilled, the depth to which they are drilled, and whether they are oil wells, gas wells or dry holes. In addition, they can be affected by whether the wells are stimulated. Subregional detail from the Joint Association Survey (JAS) was aggregated to estimate regional averages for the depth intervals used in the model. In addition to the standard costs of drilling and completion, gas wells drilled in low permeability reservoirs are assumed to have additional well stimulation costs.

Equipment Cost

Well costs include all drilling and completion costs through the "Christmas tree." Additional items past the Christmas tree needed for producing wells (e.g., flowline and connections, separators, dehydrators, pumps and storage tanks) are included as lease equipment costs. Estimates for lease equipment costs were derived from an annual survey conducted by the Dallas Field Office of EIA. Estimates for lease equipment costs are contained in the model by region, depth interval and type of well (oil or gas).

Operating and Maintenance Cost

Operating and maintenance costs are dealt with in the model primarily as annual costs per well. These costs are represented by onshore region, depth interval and type of well (oil or gas) and were derived from the same EIA survey used to develop lease equipment costs.

Gas processing costs for liquids extraction is treated in the model as a deduction from NGL revenues. Additional processing costs attributable to non-hydrocarbon gas removal are explicitly added in several areas. The costs are included in the model as an operating cost in dollars per MMBtu of marketable gas.

Environmental Compliance Costs

Upstream environmental compliance costs above those embedded in the baseyear cost data can be added in the model as part of scenario development. This is done by adding per-well capital and operating costs associated with an impending or hypothesized environmental regulation. Costs are specified for new wells separately from existing wells.

Offshore Costs

Within the model, the Central and Western Gulf of Mexico Offshore region is broken down into four water-depth intervals: 0-40 meters, 40-200 meters, 200-1,000 meters, and 1,000-3,000 meters. The Norphlet trend of offshore Alabama, Mississippi and Florida is included as the first interval of region BO, while the eastern Gulf of Mexico (west Florida shelf) is included as the second interval of region BO. The Atlantic continental shelf (region AO) is divided into three geographic regions running from north to south. The offshore Pacific is broken down into two intervals: 0-200 meters and 200-1,000 meters. "Average" or "typical" physical parameters are assumed for each interval for the purpose of developing offshore well, platform, production equipment and operating costs.

Other Costs

Other cost items contained in the Hydrocarbon Supply Model were developed from expenditure data contained in the annual Census and API surveys of oil and gas expenditures. These include leasehold costs exclusive of lease bonuses, geological and geophysical surveys, scouting and land rents and overhead. The model represents these costs as a fraction of the direct well and equipment costs.

Changes to Costs Over Time

The model calculates changes to real dollar base costs over time as industry activity and oil and gas prices change. Algorithms esti-

mated from 19 years of historical data are used to create an index of future costs. A separate algorithm exists for well costs by depth interval, equipment costs, operating cost and overhead. The algorithms use forecasted oil and gas prices and active rotary rig counts as their input.

Endogenous estimates of cost changes due to industry activity and prices are limited by application of cost bounds. The bounds used in the model represent long-term limits on charges for the various components that make up the cost of drilling a well. Each component has a cost floor, and an upper bound expressed as a range (high and low upper bounds). These bounds are based on analysis of long-term trends in drilling costs, with special attention paid to rig contractor payments and the replacement cost of rigs in determining the bounds for well costs.

2.5 Discounted Cashflow Analysis

The logic of the Hydrocarbon Supply Model is designed to simulate the decisionmaking process that takes place within an oil and gas company. This is done through discounted cashflow (DCF) analysis of investment programs made of successive new field exploratory drilling increments, continued development of existing fields and investment in "cells" within the Enhanced Recovery Module.

For instance, with regard to new fields, the drilling of 300 exploratory wells in the 10-15,000 ft. depth interval of South Louisiana onshore, plus all subsequent development and production activity for oil and gas fields found by these wells, would be considered a new field investment program. The next 300 exploratory wells would be another program, and so on. When evaluating the economics of undertaking a new field exploration program, the model considers many of the same factors considered by a company making a similar decision. Specifically, the Hydrocarbon Supply Model includes the following items in its DCF decision framework:

- Expected oil and gas prices and expected hydrocarbon discoveries (characterized by the find-rate equations in terms of the expected number of oil and gas fields in 20 size classes),

- Assumed takes as a percent of deliverability for gas fields in reflection of market conditions, and
- Producers' costs for lease acquisition, geological and geophysical costs, drilling, operation and maintenance, etc.

All cash outflows and inflows are characterized by the year they take place. Many of the expenditures for exploratory drilling, along with some development and production expenditures, occur in the first year. Revenues from oil, gas and natural gas liquids production may begin in the first year and will continue for several years. In performing the DCF analysis, the model evaluates costs and revenues for 20 years from when the investment program begins. Within the model, each dollar of expenditures and revenues associated with an investment program is adjusted to a net, after-tax basis and discounted at an assumed minimum required rate of return.

Investment programs with a positive present value (i.e., those with rates of return at or above the minimum ROR) are considered financially acceptable and may be undertaken by the model. The criterion used in the model to select among financially acceptable investment programs is the "profit index." This is calculated as the internal rate of return minus the minimum required ROR. When several programs, each of which meets the minimum required ROR criteria, are available in a given model period, the model generally selects first those with the highest profit indices.

2.6 Logic Flow Of Model

The overall logic flow of the Hydrocarbon Supply Model is shown as consisting of eight steps in Figure 2-3. The model begins at Step 1 by setting initial values for many variables, including data for old field probables inventories. At this point, these inventories refer to undiscovered resources in fields found before the model's first year of simulation.

Step 2 in the model is to evaluate the economics of investments to find, develop and produce reserves in old fields. The model compares expected oil and gas prices against the minimum acceptable price of elements in the old field probables inventory. This comparison is made separately for oil and gas fields in each region and depth interval.

In Step 3, the model evaluates the economics of investments to discover new fields. Here, successive increments of new field exploratory drilling in each of the model's region/depth categories are evaluated. Part of this evaluation includes the calculation of the relative profitability of each drilling increment as measured by the "profit index", i.e., the internal rate of return minus the minimum acceptable rate of return. A similar economic analysis is performed in Step 4 for "nonconventional" gas and other types of investment characterized in the Enhanced Recovery Module.

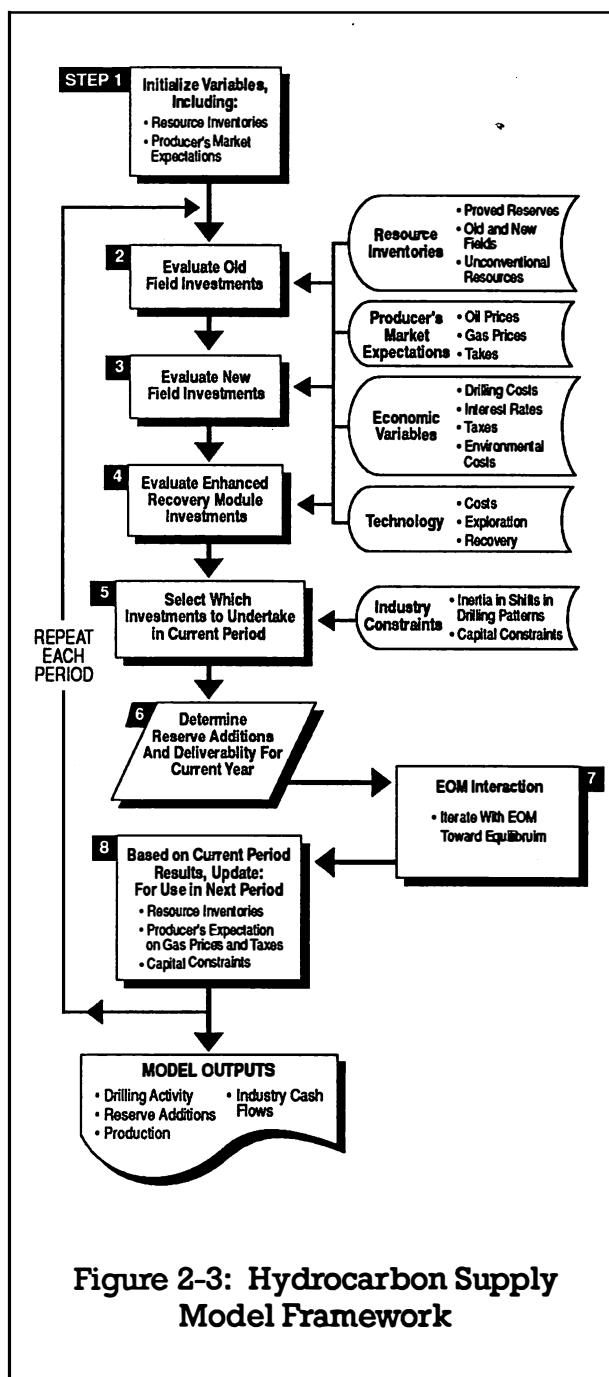


Figure 2-3: Hydrocarbon Supply Model Framework

Once investment options in old fields, new fields and Enhanced Recovery Module cells are evaluated, the model comes to Step 5, where it selects which investments to make in the current period. The selection among new field and ERM investments is done primarily on the basis of profitability, but within certain constraints designed to model industry inertia and capital limitations. All old field investments meeting the producers' minimum ROR requirements are made, unless capital constraints are binding. In that case, only a portion of each investment (i.e., of each economic element in the probables inventory) is undertaken.

After the selection process is completed, summary results are generated at Step 6 and passed to the rest of the Energy Overview Model. At Step 7 the Energy Overview Model solves for regional gas production, wellhead gas prices, transportation and distribution rates, burner-tip prices and demand for the current year.

At Step 8, the Hydrocarbon Supply Model stores the current period results for output tables and updates variables for use in the next run year. The important variables that may be updated for the next period, based on the results of the current period, include the capital constraints and the producer's expected natural gas prices and takes. The model also revises its inventories of old field probables to reflect future growth in fields discovered in the current period.

2.7 User Specifications

The Hydrocarbon Model has been designed to allow the user a great deal of flexibility in setting important model parameters to facilitate sensitivity analysis of model results. Some of the most important parameters which the user can specify are described below.

Resource Base Assumptions

There are three overall categories for resource base assumption:

New Fields: Three resource base assumptions for new fields are provided in the model. The user can specify for each depth in each region which assumption (low, medium or high) will be used.

Old Fields: The initial values for the undiscovered resource base in old fields also can be set

by the user for each region as a percent of the default values. Separate values can be specified for associated-dissolved gas (and crude), nonassociated high permeability gas and nonassociated low permeability gas.

Nonconventionals: For the Enhanced Recovery Module, the resource base is specified for each cell in terms of resource-in-place (as measured in barrels of oil equivalent) and the fraction of resource-in-place that can be recovered using each of up to three technologies.

Technology Assumptions

Assumptions regarding technologies are dealt with in three general ways in the Hydrocarbon Supply model:

Cost Factors: The base costs in the model are adjusted for general factor cost changes related to oil and gas prices and drilling activity. It is also possible to introduce technology induced cost changes through the "Rig Efficiency Index".

Exploration Efficiency: Changes in exploration efficiency due to technological changes also can be included in scenarios. The index is specified by year, where current technology is 1.00. The index is used to reduce the need to drill exploratory wells.

Recovery Factors: For the development of new fields, up to three different technology assumptions can be made by field type for each region and depth interval to represent such advancements as better completion techniques and horizontal drilling. This has the effect of increasing the size of each new field. One can also specify technology-driven changes in recovery factors for each cell in the Enhanced Recovery Module.

Environmental Compliance Costs

Environmental compliance costs beyond those in the baseyear costs can be specified in the model in one of two ways. The first, and simplest way is to specify an annual cost increase as an index to the baseyear costs (e.g., 1.04 is a four percent increase) for the U.S. or Canada as a whole. The second way is to specify changes in costs by region, depth and type of well for one or several combined regulations. This detailed method must be used if changes in reserves and deliverability of existing gas wells are to be considered.

Rate of Return

The real, after-tax minimum rate of return demanded by producers can be specified by depth, separately for onshore and offshore areas and by type of gas (conventional, coalbed methane, shale, tight gas). Different values can be specified for each forecast year.

Tax Rates

Severance taxes and the marginal income tax rate can be set by the user by region. The beginning and end dates and operation of the Section 29 nonconventional fuel tax credit in the United States can also be varied among cases.

Offshore Lease Bonus

The model is designed to allow the user either to specify the level of offshore lease bonuses or to let the model calculate the bonus endogenously to reflect changes in gas and oil prices, resource depletion and gas market conditions.

Industry Inertia

The annual percentage changes upward and downward in new fields and ERM investments can be set by the user by type of gas. The user also can pre-specify maximum or minimum new field drilling levels by year for any depth of any region. This option can be used, for instance, to simulate restricted access to offshore leases.

Cash-Flow Constraints

The user can decide whether or not cash-flow constraints will operate in the model and the formula by which the constraints are determined. Separate constraints may be used for the U.S. and Canada.

Oil Prices

The user must specify average Lower-48 crude oil field prices (in constant dollars) to be used in the discounted cash flow investment analysis. Regional variations among crude wellhead process are set automatically in the model.

Producer's Expected Gas Prices

The user can either specify one set of future wellhead prices (in constant dollars) that will

be used to simulate producer's discounted cash flow analysis, or let the model endogenously update producers' gas price expectations each period based on the model results. Regional variations in gas prices are computed within the model primarily based on pipeline capacity and transportation cost differences among the regions.

Expected Take Levels

In the simulation of producer discounted cash flow analysis, a projection must be made of expected takes from non-associated gas fields. These takes are expressed as a percent of deliverability. The user either can specify the takes or let the model update producers' expectations for takes based on model results.

3. DEMAND MODELS

3.1 Introduction

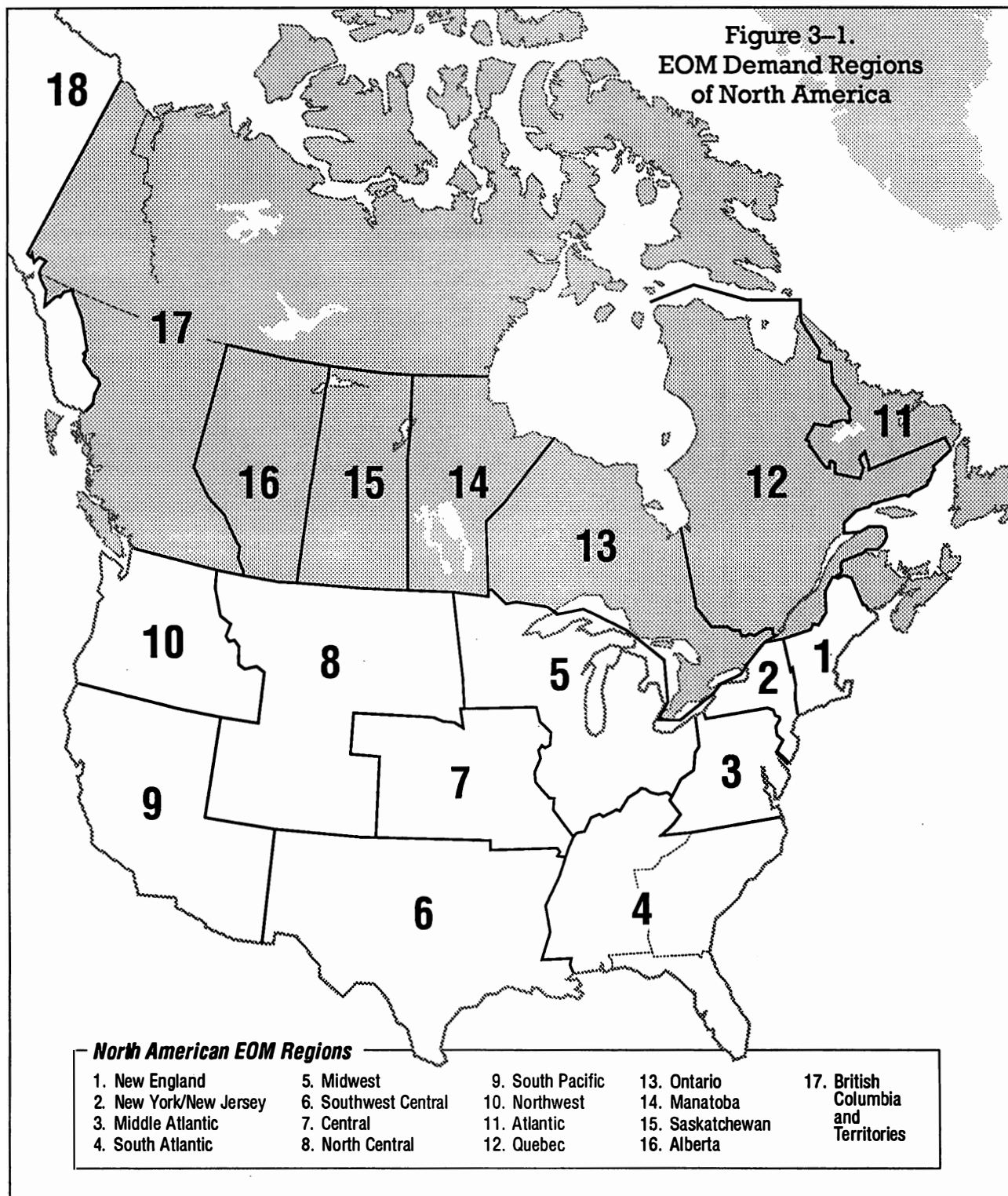
Three U.S. energy demand models are contained in the Energy Overview Model. These are the Industrial Gas Demand Model, the Electric Utility Model and the Residential/Commercial Demand Model. The industrial and electric utility models are process engineering models, in which the physical processes of energy production, conversion and consumption are explicitly represented along with their attendant costs. In these process engineering models, decisions are simulated using standard business techniques such as discounted cash-flow analysis. The third model, representing energy demand separately in the residential and commercial sectors, is an econometric model, which has been based on and calibrated to a larger process engineering model created by EEA. All three of the U.S. demand models are divided into Federal Regions shown in Figure 3-1.

Canadian energy demand is represented in the Energy Overview Model in a simpler manner than that used for the U.S. The EOM's Canadian Demand Model represents five sectors: residential, commercial, feedstocks (non-energy), industrial, transportation and electric utility. An input into the Canadian demand model is a "basecase" forecast including Canadian GDP growth, oil prices and energy demand by fuel type. This is most often taken from a forecast of the National Energy Board. The EOM's Canadian Demand Model applies

income elasticities, price elasticities and fuel switching curves to adjust these "basecase" energy demands to reflect Canadian GDP growth and oil prices specified in the scenario and the gas prices calculated within the EOM. Demand is represented for the seven Canadian regions shown in Figure 3-1.

3.2 Industrial Gas Demand Model

The Industrial Gas Demand Model is a reduced-form version of EEA's Industrial Fuel Choice Analysis Model (IFCAM). IFCAM is a highly disaggregated process engineering model designed to analyze factors affecting fuel choice decisions in the industrial sector. Since



1978, IFCAM has been used to support policy analyses and forecasting requirements for wide variety of government and private users. The model also uses energy efficiency relationships which are derived from another process engineering model developed by EEA, the Industrial Technology Use Model (ISTUM).

Each of the EOM's demand models is structured to focus on critical issues which affect the demand for natural gas and other fuels. Three key issues are related to the future development of the industrial gas market:

- The rate of growth of total industrial energy demand
- The pace of coal and electricity market penetration in the industrial sector
- Oil and gas substitutability.

Future changes in the mix of industrial products and processes, conservation and combustion equipment efficiency improvements and the future relationship between industrial production growth and total industrial energy demand are some of the key parameters that will affect the rate of growth of total industrial energy demand. The Industrial Gas Demand Model forecasts total energy demand considering the impact of regional energy costs and industrial production growth forecasts by major industry group (SIC). The model then allocates total industrial energy demand by SIC and region and determines the mix of new and existing industrial combustors and alternate fuel-firing capabilities.

To a large extent, steam coal and electricity market penetration are a function of projected growth in total energy demand and the turnover of industrial capital stock. Most existing industrial combustors cannot technically be retrofitted to burn coal (or electricity). Coal and electricity will compete for market share primarily to serve production expansion requirements for some (but not all) processes. Depending upon the expected rate of increase of oil and gas prices, some existing oil/gas combustors could be retired early and replaced with new coal-fired combustors or electric heaters.

The Industrial Gas Demand Model addresses the economic, environmental, technical, and regulatory issues which affect the rate of turnover of capital stock and the capital and

O&M cost differences for coal *versus* oil/gas use, including:

- Unit size and operating rate
- Local, State and Federal air emissions regulations
- Regional fuel price variability
- Technical feasibility constraints which limit the applicability of residual fuel oil as a retrofit option for some existing gas combustors
- Fuel-firing capability of existing units.

Technical constraints on fuel firing capability are more relevant for coal, heavy fuel oil and electricity use in industrial process heat markets. There are opportunities for coal use in process heat applications in the Petroleum Refining, Stone, Clay and Glass, Steel and Aluminum industries. Some are in current use. Others have risks related to design problems, potential materials failure, equipment downtime or safety hazards.

Oil and gas substitutability is a third (but not least important) issue. While coal and electricity compete with oil/gas generally in long-term new capital stock decisions, gas competes with oil in any time frame. Dual oil/gas firing capability has been added to some existing combustors and dual fuel capability is generally being incorporated in designs for new units in order to promote increased flexibility — to be able to react quickly to market changes in fuel prices and supply availability. Therefore, alternate fuel-firing capability is a key factor related to short-term fuel choice decisions between fuel oil and natural gas.

With respect to the short run decision between oil and gas, the model considers:

- Technical constraints limiting retrofits from natural gas to heavy fuel oil,
- Decisions to install new alternate fuel-firing capability,
- Retrofit costs which are specific to unit size, operating rate and combustor type,
- Environmental regulatory requirements which affect capital and operating costs and/or limit the industrial user to a high quality fuel oil.

The Industrial Gas Demand Model includes the major economic, environmental, and technical factors needed to address the key issues affecting natural gas demand in the industrial market.

Scope of Model

The Industrial Gas Demand Model projects demand curves for natural gas for two groups of industrial combustors:

- Boilers
- Non-boilers (or process heat equipment).

The Industrial Gas Demand Model addresses the projected consumption of fossil fuels (natural gas, distillate and residual fuel oil and non-metallurgical coal) and electricity in industrial combustors. Table 3-1 summarizes the coverage of this model with respect to U.S. Department of Energy (DOE) Energy Information Administration end-use categories.

Analytical Framework of IGDM

The Industrial Gas Demand Model is a process engineering model which simulates the effects of specific policies on new and existing technical alternatives through the application of direct engineering information. The model character-

izes industrial energy uses at a very disaggregated level. Based on the characteristics of each combustor (i.e., firing rate, operating rate, pollution control requirements, location), cost estimates are generated for the options of choosing natural gas, distillate fuel oil, residual fuel oil and coal. The cost estimates include capital, operating, maintenance, and fuel expenses for the combustor and pollution control equipment.

For each group of industrial combustors, the model projects the least-cost alternative to natural gas demand and the "break-even" natural gas price. The "break-even" natural gas price is defined to be the fuel price such that the natural gas total life-cycle costs (capital, O&M and fuel) equal the least-cost alternate fuel's total life-cycle costs. The annual fuel consumption and "break-even" natural gas prices are aggregated into two sets of regional industrial natural gas demand curves: boilers and non-boilers. These natural gas demand curves are then passed to the integrating elements of the Energy Overview Model.

Figure 3-2 presents the major features of the analytical framework of the Industrial Gas Demand Model and is discussed in the following sections.

TABLE 3-1
COVERAGE OF INDUSTRIAL FOSSIL FUEL CONSUMPTION
IN THE INDUSTRIAL GAS DEMAND MODEL

Fuel Type	DOE/EIA End-Use Categories		DOE/EIA Publication Reference
	Included	Excluded	
Natural gas	Industrial	Lease and plant fuel Pipeline fuel	Natural Gas Annual
Distillate Fuel Oil	Industrial Off-highway diesel Oil company Farm	Military Railroad Vessel bunkering All other	Petroleum Supply Annual
Residual Fuel Oil	Industrial Oil company	Military Railroad Vessel bunkering All other	Petroleum Supply Annual
Coal	Other industrial	Coke plants	Quarterly Coal Report

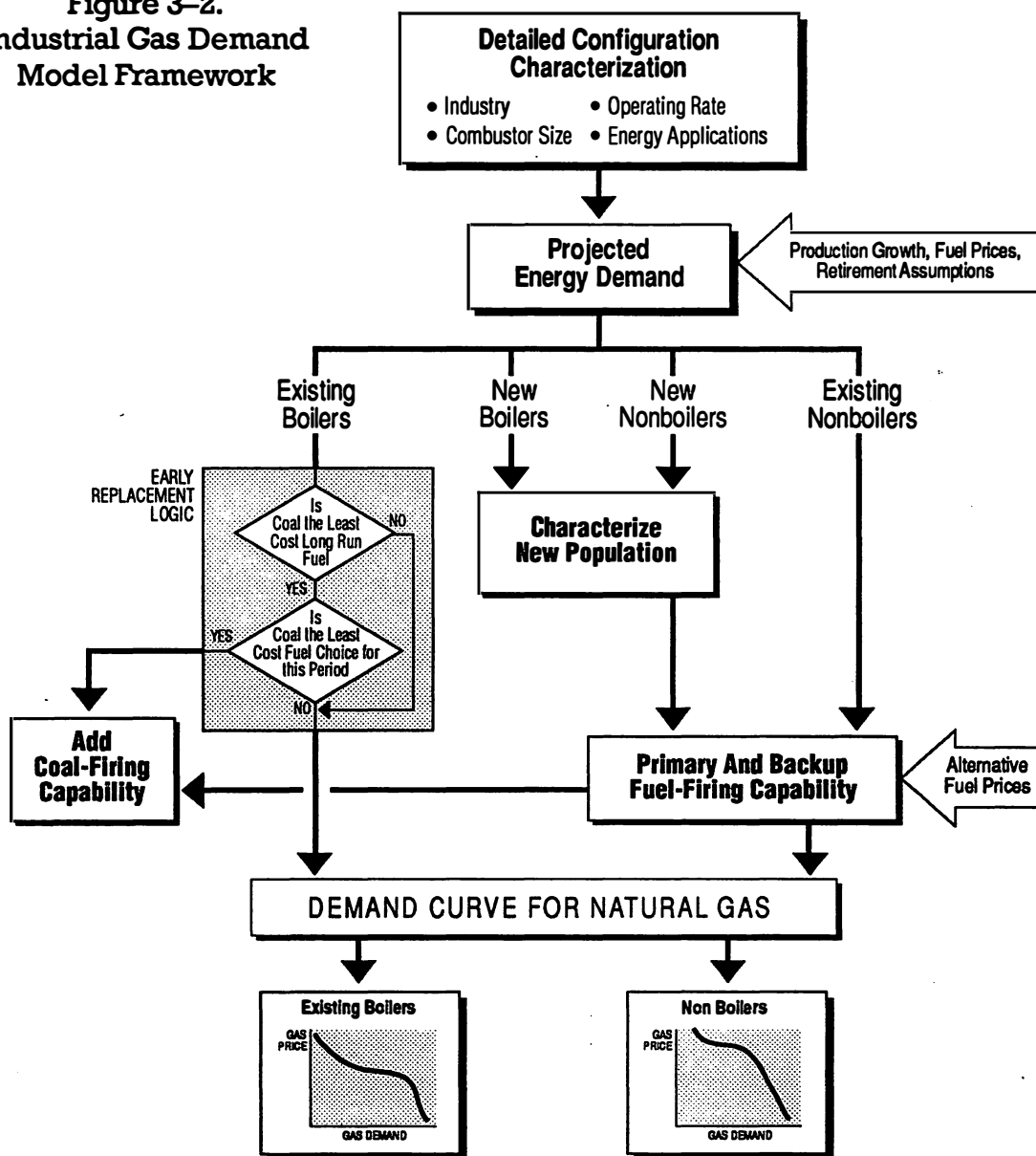
Total Energy and Combustor Population

Industrial production and fuel price elasticities are used in the model to project total industrial energy demand by industry group in IGDM. These are summary relationships developed from projections from EEA's Industrial Technology Use Model (ISTUM). ISTUM covers total industrial energy use — all energy covered in EIA's definition of industrial energy use plus biomass and by-product fuels. The elasticities derived from ISTUM reflect basic energy effi-

ciency improvement trends and changes in the mix of fossil fuels and electricity in comparison to other energy sources.

User-specified inputs for industrial production growth rates and the prices of fuel supply options other than natural gas are input to this segment of the model, which projects energy consumption for each region and industry group. Within each industry group/region, the energy is then broken down into functional use classifications which are retained throughout the analytical framework. These functional

Figure 3-2.
Industrial Gas Demand
Model Framework



uses include boilers and about 50 distinct process heat uses applications (such as furnaces, ovens, kilns, and heaters) plus gas feedstock use and off-highway oil uses. The incremental energy associated with the growth in cogenerated power within the industrial sector is input exogenously into IGDM.¹

Existing Units

The population of "existing" combustors in the base year is identified by type of combustor, Federal region, firing rate, capacity utilization rate and alternate fuel-firing capability. The original base year for the combustor population was the mid-1970's, based on the following data source: DOE's Major Fuel Burning Installation (MFBI) survey (Form No. FEA C-602-S-0) and EEA's Energy Consumption Data Base (industrial energy consumption estimates by fuel type, region, industry group and functional use) which was prepared for DOE. EEA updated the characteristics of the combustor specific population in a more recent study, using primarily confidential information developed from pipeline and gas distributor data bases. The results of this update were summarized in a report for the Department of Energy completed in 1986.

The model has been calibrated to 1989 regional DOE estimates of industrial natural gas, distillate fuel oil, residual fuel oil and non-metallurgical coal demand. Therefore, 1989 is the current base year in the model. The inventory of existing units changes over time in the model due to retirements of the units or, possibly, due to declining industrial output.

Characterizations of New Combustors

The portion of total energy not accounted for by existing units within a functional use category is allocated as new combustor fuel use. New combustors are identified by:

- Type (boiler or one of over 50 types of process heat equipment)
- Size and operating rate
- Federal region
- Applicable air emissions regulations.

Historical data for each industry group are used to assign combustor type, size and operating rate parameters.

The designed primary fuel-burning capability of each new combustor depends on an economic choice comparison of after-tax capital, fuel, and O&M costs discounted over the expected life of the combustor. The fuel choice considers the technical requirements of each process, environmental control requirements, fuel combustion equipment required and associated operating costs, as well as any other regulatory restrictions that have been imposed. The final decision is whether the new combustor will burn oil/gas or coal as a primary fuel.

The Industrial Gas Demand Model solves for both the long run decision regarding the fuel firing capability of new units coming on line and also for the short-term (within 1 year) fuel oil alternative to natural gas. A long-term decision is made to determine fuel choice for the capital investment in the new boiler or process heater. Once the fuel firing capability of new combustors have been determined, the short-term decision section of the model chooses between oil and gas for all combustors, including both new and existing units. This second step in the two-part fuel choice decision, provides the demand response for natural gas and fuel oil to short-term fluctuations in oil and gas prices.

When a boiler or process heater already has fuel oil and gas firing capability, short-term fuel switching can be performed with only operating cost expenses. For other combustors which are not dual-fired, the model considers technical constraints, fuel conversion costs, environmental regulations plus fuel and O&M costs on an after tax basis. For the short-term decision to install fuel oil firing capability, the model assumes a three year payback period is need to recover equipment costs. Effectively, the model at this stage determines the alternative fuel that would be fired (in the short run) as an alternative to natural gas.

Demand Curve Output

For each existing or new combustor, the model calculates the life-cycle costs for the least-cost

¹ The "incremental" energy includes only the extra energy required to generate power and does not include the other energy required to generate steam to satisfy process heat demands. Typically, estimates of cogeneration includes both needs for energy. In IGDM, the energy for process steam is reported under boilers and the extra energy required to generate power is included as cogeneration.

non-gas alternative (distillate fuel oil, one of four sulfur classes of residual fuel oil, high sulfur coal or low sulfur coal). The model subtracts the non-fuel life-cycle costs of natural gas combustion and the residual is the "break-even" marginal gas burner-tip price — i.e., the unit would burn gas at any price below this "break-even" price. Gas demand curves are generated by aggregating the annual fuel demand and marginal gas burner-tip prices for each group of combustors. Separate regional industrial natural gas demand curves are generated for total industrial boilers and total industrial non-boilers. These demand curves are then passed to the integrating framework of the Energy Overview Model.

3.3 Electric Utility Model

The purpose of the Electric Utility Model in the Energy Overview Model is to determine gas consumption in the electric utility sector and to estimate electricity prices for the industrial, commercial and residential sectors: The Electric Utility Model:

- Tracks capital stock changes in the regional powerplant inventory
- Projects long-term fuel choices in new generating units
- Makes short-term oil/gas fuel choice decisions

- Projects regional electricity production costs and fuel consumption
- Projects regional electricity prices by sector through revenue requirement calculations.

There are 23 types of powerplants represented in the model (see Table 3-2). The model retires existing capacity and adds new capacity so as to maintain desired reserve margins.

Logic of Electric Utility Model

Figure 3-3 presents an overview of the Electric Utility Model. The overall logic of the model can be broken up into two parts. The first set of steps, which are shown in the upper area of the figure, are performed once each model period. These steps retire existing plant and add new plant capacity, and thus determine the total installed capacity by load type by region for each period. The second part of the model has steps which may be performed several times within a period, as the Electric Utility Model iterates with the rest of the EOM toward reaching an equilibrium. The steps in the second part include plant dispatching, oil/gas fuel switching, calculation of revenue requirements, and determination of electricity rates by sector. At the end of these steps, gas consumption by electric utilities and electricity rates have been determined and are sent back to the EOM.

TABLE 3-2
ELECTRIC UTILITY MODEL PLANT TYPES

Plant Type	Description	Plant Type	Description	Plant Type	Description
1	Oil-fired steam	10	Combined cycle natural gas	17	Low sulfur subbituminous coal, no scrubber
2	High sulfur bituminous coal with scrubber	11	High sulfur bituminous coal, no scrubber	18	Medium sulfur lignite coal with scrubber
3	Medium sulfur bituminous coal with scrubber	12	Medium sulfur bituminous coal, no scrubber	19	Low sulfur lignite coal with scrubber
4	Low sulfur bituminous coal with scrubber	13	Low sulfur bituminous coal, no scrubber	20	Medium sulfur lignite coal, no scrubber
5	Natural gas-fired turbine	14	Medium sulfur subbituminous coal with scrubber	21	Low sulfur lignite coal, no scrubber
6	Distillate oil-fired turbine	15	Low sulfur subbituminous coal with scrubber	22	Pump hydro
7	Combined cycle distillate	16	Medium sulfur subbituminous coal with scrubber	23	Nuclear
8	Natural gas-fired steam				
9	Hydro, other renewables				

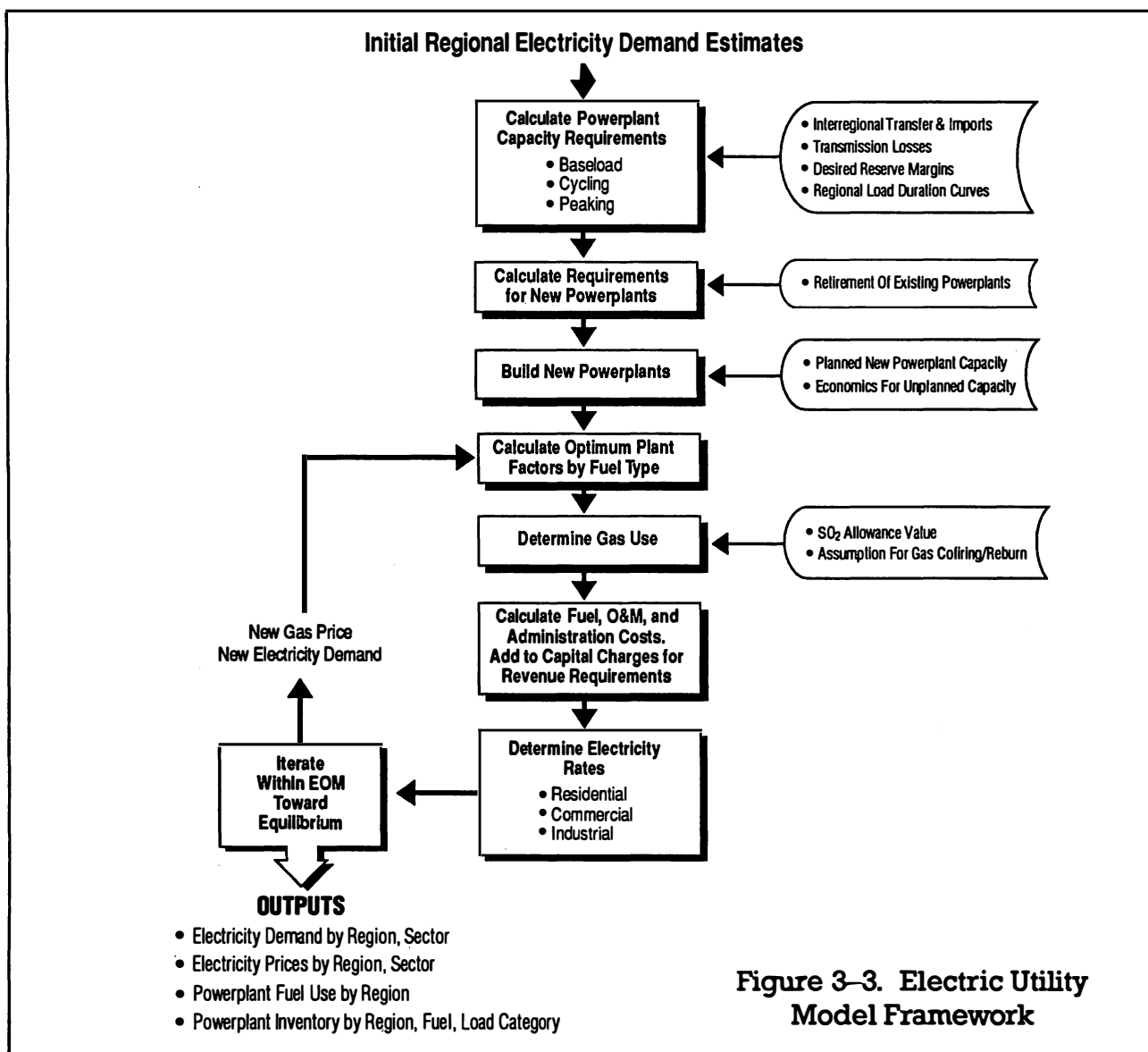
Each of the key steps in the model's logic is described in greater detail below.

Calculation of Powerplant Capacity Requirements

The first step in the model is to take a preliminary estimate of electricity demand from the EOM and to compute the required megawatts of installed capacity by region by generating class (base, cycling, peaking). The preliminary estimate of electricity demand is computed in the EOM as a fixed rate of growth by region from the model's solution demand in the previous period. Generating needs by region are calculated by taking into account how much electricity is transferred across regions and from Canada. The model next takes these generating needs in megawatt hours and

transforms them into megawatts of required capacity by load class. This step includes considerations for transmission and distribution losses, desired reserve margins, average system load factors, and the regional load duration curves.

The model maintains its inventory of existing plants by load class and type. It simulates the process by which older fossil fuel steam plants are demoted from baseload service to cycling over time as new plants are built. Due to the higher operating cost of oil and gas steam units in comparison to coal, the model will first demote oil and gas steam units from base to cycling. Since older baseload plants are moved to fill any gap in capacity requirements for cycling duty, all new steam plants added by the model initially go into baseload service.



Normal Retirements of Powerplants

The inventory of powerplants in the model is derived from DOE's Generating Units Reference File (GURF). This file describes the physical characteristics for all existing generating units and future generating units for which construction should be completed within the next ten years. The existing plants have been sorted into age groups for coal and oil/gas plants and this information has been put into the model. The model may retire plants when their age reaches a specified limit. For most scenarios, a considerable amount of plant refurbishment is assumed and a large portion of the old plants are kept active past their "normal" retirement age. The cost of this life extension is included in the model's capital requirements. In some scenarios, it is further assumed that some of the old units will be "re-powered", i.e., additional capacity added at the time of refurbishment.

Fuel Selection for New Plants

The type of new plants are added in the model is determined in two ways:

- from a list of plants contained in the PLANTS file, and
- based on economic competition.

Typical scenarios for new powerplant capacity include specification by type for all announced plants plus a certain number of unannounced hydro/renewable plants. The remaining capacity is determined in the model by an economic competition between coal and gas.

Specific Assumptions for the Long-term Economic Decision

The economic competition for new, baseload plants which might fire either natural gas/oil or coal is made on the basis of long-term economics, considering the capital cost, non-fuel O&M and fuel costs over an expected 30 year operating life of the new generating facility. The following assumptions are used in the determination of the fuel firing capability of new, baseload generating capacity coming on line after 1996 based on the minimization of life cycle costs for new generating plants.

Size of New Plants: The model simulates costs for both a "large" and a "small" plant size.

New plants less than 400 MW are classified as small. For costing purposes, the small size is represented by a 300 MW unit and the large plant by a 500 MW unit. The distribution of new, baseload plants by size through the year 2000 is based on the pattern of planned capacity additions of natural gas and coal fired units as reported by NERC (the trend now emphasizes the small unit size); after that date it is assumed that, as large scale generating capacity additions are needed, the size distribution of new plants shifts toward the larger unit sizes reflecting the historical experience during periods of rapid electricity growth.

Capital and Non-fuel O&M Costs: Capital costs for the base year (1990) were derived from the 1989 EPRI TAG report, with the adjustment noted below to raise the costs of gas-fired units. A combined cycle plant is used as the representative gas fired unit for both sizes. Although plant cost data can vary by region, the default is to set plant costs data to that for the Midwest region of the U.S., (the East North Central region) as identified in the TAG. Capital (including AFUDC) and O&M costs were assumed to be in 1988 dollars and were escalated for inflation to \$1990. Discussions with utility industry representatives familiar with new plant costs resulted in an upward adjustment of the TAG capital costs for combined cycle gas-fired units to \$700/kw to reflect the costs of new plants now coming on line.

Escalation in Capital Costs: The capital costs for both coal and natural gas fired units may be escalated after 1990 at a real per annum rate. Although historical data on capital costs indicate a rate of escalation which is roughly three percent per annum, it is generally felt that much of this cost increase was due to the rising equipment costs related to environmental control. Given that the scenarios for the impact of environmental costs are defined separately, a future cost escalation of one percent per annum in real terms for new capacity additions is typically used.

Fuel Prices: The cost of fuel for the new gas-fired generating plants is a weighted average of natural gas and distillate oil prices, with the weighting for distillate being a user-specified input. For example, a scenario which assumes that long-term gas wellhead contracts and semi-firm transportation sources will be used for the combined cycle plants might assume

that distillate will be burned for the equivalent of five full days during the year. This reflects a minimal amount of interruptions of natural gas supplies during the year.

Although perfect foresight is assumed for future fuel oil and coal prices, the model does not always assume that utilities have perfect foresight regarding future natural gas prices. The user can specify one of three separate options for expectations regarding future natural gas prices:

- Assumes electric utility planners have perfect price foresight,
- In each year, gas prices in future are assumed to reflect a continuation of the trends in the most recent 3-5 years, or
- Delivered gas prices are assumed to move up over a five year period to reach and then track the predominant residual oil as dictated by that region's environmental requirements.

Treatment of Environmental Factors: Environmental factors are built into the modeling approach at two levels. At the first level, capital and fuel costs of new units reflect the need to comply with environmental requirements such as the New Source Performance Standards. For example, the costs of SO₂ scrubbers has been included in the capital costs of coal fired units. These costs are based on expected implementation of current legislation and do not consider possible changes to environmental legislation in the future.

The second level of costs relates to the anticipated cost of purchasing SO₂ allowances for new coal fired facilities. The costs of purchasing SO₂ allowances are added into the costs of coal, considering the differences in sulfur content of coal being used in various regions. The user must input the cost of SO₂ allowances (\$ per ton) by forecast year.

Solution Algorithm for Gas Market Share: Given the above inputs on capital, O&M and fuel related costs for new natural gas and coal fired generating plants, the model calculates a leverized present value of the total life cycle costs of a new coal plant compared to a new gas plant for each size class in each region for the year when the plant would come on line. All cost inputs are in real terms and a real discount rate (typically 8%) is used in the present value calculation.

These present value costs are then input into a set of market share algorithms (by plant size and region) which determine the gas market share for the economic decision logic. The algorithms are based on logit curves which were calibrated such that the gas market share equals 50% when the costs of a new natural gas-fired plant is equal to the cost of a coal-fired plant.

Considerations for Institutional Factors

There has been some controversy regarding whether or not near-term decisions regarding fuel firing capability in new generating facilities are based on long-term economics (cost minimization over the useful plant life) or whether decisions are biased in favor of natural gas because of "institutional" factors which are not captured in the long run economic logic. Hence, the electric utility model has an option which permits users to base fuel choice decisions on long run economics or institutional factors. Both factors can be included in one model run by specifying the time periods during which each would drive model decisions.

The institutional factors which would tend to bias results in favor of natural gas include:

- A perception of very low natural gas prices in future, because prices are low now, favoring natural gas. In effect, utilities understate future increases in the price of gas until price increases actually begin to occur.
- The combination of excess generating capacity in many regions, the uncertain growth in electricity demand, utility financial problems and a regulatory attitude which makes recovery of capital costs in new plants uncertain, all lead utilities to have a tendency to bring on line oil/gas fired capacity because capital costs per KW are considerably less than for coal.
- In this uncertain environment utilities will delay new construction decisions as long as possible, which also tends to favor the choice of oil/gas fired units since their construction lead time is much shorter than for coal fired units.

This environment may be assumed to persist until near the end of the decade (years 1997-98) when: natural gas prices are clearly esca-

lating (dispelling the perception that natural gas prices will remain near \$2 per Mcf "forever"), excess generating capacity has been worked off in most regions by the slow growth in electricity demand and the need for new capacity becomes more pressing, utility financial woes have eased and regulators, recognizing the need for new generating capacity, adopt attitudes which once again encourage utilities to install more expensive coal fired capacity. At that point the long-term economics of coal *versus* natural gas/oil costs begin to become the dominant factor influencing the choice of fuel firing capability.

During the period when the "institutional/short-term market forces" are relevant, the model can be told to determine the regional market share of natural gas fired capability by selecting the higher of the market shares determined by long-term economics or by institutional constraints.

For instance, the mode of implementing these "institutional" factors and the specific timing could be as follows:

- Prior to the years 1997, fuel firing capacity is determined by announced utility plants,
- For specific years where institutional factors are assumed to drive gas/oil vs. coal decisions (typically through the end of the 90's, the user may impose a "minimum" gas market share which (by default) is set by the gas *versus* coal market shares from planned utility announcements for new generating capacity.
- The environment changes to favor coal for new capacity decisions starting in '97-98; but a decision in 1997-98 to start building a coal plant does not actually affect fuel consumption until that new plant comes on line seven years after the decision to initiate the project. The impact of a gradual perception of the changing economic/institutional environment plus the effect of the long construction lead time is simulating by a phased shift between the years 2000 and 2005 to a point where the long-term, economic logic then becomes the only factor determining the fuel firing capability of new generating plants. In effect, the "floor" gas market share reflecting institutional factors is phased out during this period.

Dispatching of Plants by Fuel Type

The model employs a merit order dispatching algorithm to determine the average annual capacity utilization rate for each plant type. This algorithm does not affect nuclear units, whose capacity utilization rate is specified by year as a model input. Similarly the capacity utilization rates for hydroelectric units are preset in the model.

The model dispatches coal, combined cycle, oil and gas steam units within each load class. It begins by first dispatching the coal units up to their normal or "target" average annual capacity utilization rates. This is usually 64 percent for baseload units and 35 percent for cycling units. The next priority is given to gas-fired combined cycle units. Finally, utilization rates for oil and gas steam units are set such that the remainder of generating needs are met.

The model distinguishes heat rates by unit type and between existing facilities (as of 1990) and new generating plants installed after 1990. It is possible to adjust these heat rates for future technological advances that will be seen as new units are added and existing units are refurbished. For new units, a typical assumption would be a six percent improvement in heat rates for units coming in line in the year 2010 *versus* 1990 with units added over time gradually improving heat rates to achieve the 2010 target heat rate.

Oil and Gas Fuel Switching

The model simulates the switching between oil and gas in steam units and turbines based on minimizing fuel costs within certain user-specified constraints. The model calculates the fraction of energy use to be met by natural gas as function of the price difference between gas and the competing fuel oil. For steam units, the competing fuel is a residual oil of one of four sulfur contents: 0.3%, 0.7%, 1.3%, or 2.0% sulfur. (These are the same designations used in the Industrial Gas Demand Model.) Depending upon environmental regulations, a portion of plants in each region will be designated in the model to burn one of these four types of residual oil. For turbines and combined cycle units, natural gas competes with distillate fuel oil.

The calculation of natural gas market share is done with "fuel switching curves", which indicate how market share changes with the price

of gas and the competing oil product. Figure 3-4 is an illustration of such a curve. The shape of these curves varies among regions based on the region's installed fuel firing capability. The fuel price differential is the price of gas minus the price of the competing oil. The market share corresponding to each value in the fuel price differential is on the vertical axis. The market share of gas has three "steps" which are connected by sloping lines. The upper step represents the highest possible market share, which is reached when gas is the most advantageously priced. This represents a saturation of the market for all units which have the physical capability to burn gas and which are connected to gas supplies. The first sloping line represents the dual-fuel capable units. The next step represents the portion of units which can burn gas but which does not currently have fuel oil capability. Such units are found in large numbers only in the Southwest (model region #6). These units will not switch away from gas until gas has a significant price disadvantage compared to oil. The third step (at 0 percent market share) represents the loss of these gas-only units to oil.

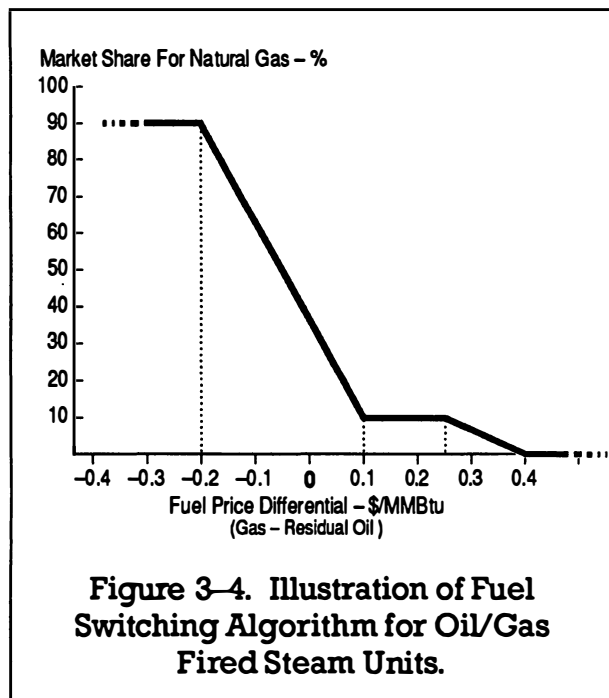
The calculation of market share is performed in the model for steam units separately for each of the four residual fuel oil sulfur content markets within each region. After the 2000, the cost of an SO₂ allowance is factored into the gas-resid switching decision. Market share is calculated

for gas use in turbine and combined cycle units using the fuel price differential with distillate fuel oil.

Calculation of Revenue Requirements and Rates

Electricity rates are determined in the model through a revenue requirement calculation of the total dollar amounts to be recovered each year in each region. As new powerplants are built in the model, their capital costs are added to vintage accounts. These vintage accounts are depreciated separately and decline in their contribution to total rate base over time. Capital related charges (return on capital, depreciation, taxes, and insurance) are calculated from total rate bases for each period and take into account regional variation in the mix of private and publicly owned utility property. Operating costs for fuel, operating and maintenance expenses, and administration are added to capital related charges to derive total revenue requirements.

Total revenue requirements are then translated into rates by customer class: residential, commercial, and industrial. The capital costs are allocated to each class based on historical allotment practices. The variable costs for fuel, operating and maintenance and administration are divided equally among classes on a cents per kilowatt-hour basis. The resulting electricity rates are a sum of the fixed and variable cost components.



3.4. Residential/Commercial Model

Some of the key issues related to the natural gas market in the residential/commercial sector include:

- Building shell energy efficiency improvements
- Combustion efficiency improvements for space heating and cooling and water heating equipment
- Impacts of building energy and appliance efficiency standards
- Effects of changing housing preferences
- Short-term competition with fuel oil
- Importance of emerging technologies (e.g., gas-fired heat pumps, gas pulse combustion furnaces, passive solar)

- Consumer behavioral effects (i.e., comfort versus energy costs)
- Effects of variable climatological parameters (i.e., heating degree-days)
- Rate of increases in housing and commercial building floor space.

Three of these factors directly influence fuel demand — HVAC equipment efficiency, the thermal performance of the structures, and the system operating characteristics. For example, increasing energy prices may prompt a user to reduce fuel consumption by replacing equipment, installing insulation, or lowering his thermostat. The decision to lower the thermostat setting represents a tradeoff between lower fuel bills and higher levels of discomfort for the individuals inside the unit. The decision to increase the thermal integrity of the building structure by methods such as increasing the level of ceiling and wall insulation, adding storm windows, caulking, and other conservation methods represents a tradeoff of higher capital costs today for lower fuel costs in the future. A third tradeoff can be made between combustion efficiency and equipment capital costs such as by installing an electric heat pump.

These factors imply a set of trends gradually altering the nature of gas consumption in the residential and commercial sectors. The overall energy use trends imply a very gradual shift toward more efficient combustion equipment and thermally efficient building shells as the building capital stock is gradually replaced by new structures. Furthermore, the market share for natural gas in space heating functions is subject to competition from electricity, in the form of heat pumps and electric resistance heating. Again, this competition between natural gas and electricity will reflect gradual shifts as the building and combustion equipment stocks are replaced.

EEA has developed a process-engineering model to address these energy issues in the residential and commercial sectors. However, since residential/commercial natural gas trends will shift slowly relative to other sectors of the economy, only a simplified, reduced-form version of the residential/commercial demand model for natural gas is incorporated into the Energy Overview Model. The reduced form version of the model was developed and cali-

brated to insure that forecasts of gas demand were comparable with the results from the large scale, process model of these sectors.

Form of the Demand Curves

The methodology focuses on determining the fuel consumption of average residential buildings and average commercial buildings. Average building fuel consumption is multiplied by regional building stocks to determine total regional fuel consumption. The level of consumption of fuel type i (Q_i) in an individual building will change in response to a change in fuel price j (P_j) or in response to a change in per capita income. The price elasticity of demand for Q_i (E_{ij}) is defined as the proportionate rate of change of Q_i divided by the proportionate rate of change of P_j with other fuel types and income constant:

$$E_{ij} = \frac{\delta(\log Q_i)}{\delta(\log P_j)} = \frac{P_j}{Q_i} \frac{\delta Q_i}{\delta P_j} \quad (3-1)$$

If $i=j$, this represents the own price elasticity; if $i \neq j$, it represents the cross price elasticity of demand. The income elasticity of demand is similarly defined as the proportionate change in the level of Q_i relative to the proportionate change in per capita income (Y) with fuel prices constant:

$$N_i = \frac{\delta(\log Q_i)}{\delta(\log Y)} = \frac{Y}{Q_i} \frac{\delta Q_i}{\delta Y} \quad (3-2)$$

If the price and income elasticities of demand are assumed to be constant for different levels of price and income over an appropriate range, then a functional form for the demand curve may be derived. The functional form for the demand curve is derived directly from the equations defining elasticities. The demand curves for fuel type i and region r may be represented as:

$$\log Q_{ir} = A_{ir} + \sum_{j=1}^n E_{ij} \log P_j + N_i \log Y \quad (3-3)$$

The derivative of $\log Q_{ir}$ with respect to the log of any fuel price or the income will result in the appropriate elasticity.

Proper implementation of the demand curves depends on a thorough understanding of fuel consumption in a residential or commercial building. Fuels within a building are con-

verted by energy technologies into usable energy forms. For example, the primary use of natural gas within a building is for conversion into space heat, hot water, or heat for cooking. A building may react to a fuel price increase two ways: first, fuel consumption may be reduced through decreased use of an energy technology (e.g., reducing the thermostat setting of the space heater) or by increasing the efficiency of the existing units (e.g., installing additional jacket insulation to a water heater). Second, a more cost-effective technology or fuel may be used. For example, a building may switch from an electric furnace to the more efficient electric heat pump or from an oil furnace to a more cost-effective gas furnace.

The nature of fuel consumption in buildings causes new capital stock (i.e., energy equipment in a new building and new equipment replacing retired equipment in an existing building) to respond differently to fuel price changes from existing capital stock (i.e., existing energy equipment in existing buildings). New capital stock may react to fuel price changes by choosing among several options which include decreasing equipment utilization, structural redesign of the building shell, and fuel and technology selection. The existing capital stock has fewer options available to decrease fuel consumption. As a result, new capital stock is more responsive to fuel price changes than existing stock. Thus, keeping track of the changing composition of the capital stock is important when forecasting residential and commercial sector fuel consumption.

Since the same elasticity should not be applied to both new and old capital stock, two demand curves were developed for each fuel in each region. One curve represents new capital stock fuel consumption and the other the existing capital stock fuel consumption. Both have the same functional form as equation (3-1). However, we assumed that the long-run elasticities ($E^{L_{ij}}$, N^{L_i}) would represent behavior of the new capital stock and the short-run elasticities ($E^{S_{ij}}$, N^{S_i}) represent behavior of existing capital stock. New capital stock may be fully designed in response to fuel prices, which include selection of fuel, technology, structural design, and level of utilization. By comparison, existing stock generally is constrained in its price re-

sponse to altering only the fuel and/or technology choice, thus reflecting only a short-run response to price changes.

In effect, this structure leads to a series of demand curves for natural gas. For the residential and commercial sectors separately, there is:

- A demand equation for each demand region
- Each demand equation reflects separately the demand for natural gas and other fuels in
 - new buildings
 - existing buildings
- Each equation is a function of energy prices and income.

As a part of this basic model structure, there is a building stock adjustment algorithm which accounts for the growth in the total building stock and the retirement rate of equipment in older buildings. This stock adjustment algorithm provides a basis for altering the relative importance of new *versus* old building stock over time.

This model logic is based on the premise that the short-run elasticities represent the behavior of the existing capital stock, while the long-run elasticities represent the behavior of the new capital stock.

3.5 Canadian Energy Demand

The EOM's Canadian Demand Model represents consumption in five sectors:

- residential
- commercial
- feedstocks (non-energy)
- industrial
- transportation, and
- electric utility.

Fuels covered include:

- electricity
- oil products
- natural gas
- LPG
- coal
- renewables & others

Canadian energy demand is forecast in the Energy Overview Model in a simpler manner than that used for the U.S. The primary input into the Canadian demand model is a "base-case" projection consisting of Canadian GDP growth, oil prices and energy demand by fuel type and sector. This is typically derived from a forecast of the National Energy Board with adjustments made to backout any fuel switching from gas to oil products.

The EOM's Canadian Demand Model applies income elasticities, price elasticities and fuel switching curves to adjust these "basecase" energy demands to reflect Canadian GDP growth and oil prices specified in the scenario and the gas prices calculated within the EOM. Canadian demand is represented in the seven regions:

- Atlantic
- Quebec
- Ontario
- Manitoba
- Saskatchewan
- Alberta
- British Columbia & Territories

Additionally the model calculates lease and plant gas use and gas used for pipeline fuel.

3.6 User Specifications In Demand Models

A wide variety of assumptions can be made for the demand models in specifying a case. Some of the more important assumptions are listed below.

Economic Assumptions

Several assumptions related to economic growth need to be specified including the U.S. industrial production index, U.S. personal income, U.S. commercial floor space and Canadian GDP growth. Optionally, the user may choose to alter regional and SIC allocation factors used in the model.

Incremental Gas Markets

Incremental markets include natural gas cooling and natural gas vehicles. Consumption in these markets is set by scenario in the model.

Alternate Fuel Prices

Oil product prices used in the model include four grades of residual fuel oil and a distillate oil. Gulf Coast FOB prices for these products are derived from algorithms based on average refinery crude oil prices (RACC) and 1) assumed relationships between RACC and very high sulfur resid (VHSR) and 2) the premium low sulfur resid has to VHSR. The FOB prices are converted to burnertip prices using transportation cost and tax algorithms. The user may change the RACC—VHSR ratios and sulfur premiums in these algorithms.

Coal prices must also be specified in terms of annual growth rates in price for high and low sulfur coals.

Environmental Assumptions

The model includes considerations for all important environmental standards now on the books. Scenarios for additional or revised environmental regulations can be specified for New Source Performance Standards (NSPS) for industrial boilers and State Implementation Plans (SIPs), which primarily affect the sulfur content of residual oil that can compete with natural gas.

The model also requires a scenario for electric utility compliance with the Clean Air Act Amendment's sulfur dioxide caps. This scenario includes amount of coal switching in trillion Btus per year, installation of scrubber capacity in megawatts, use of gas for cofiring and reburn in trillion btus per year and the market value of allowances in dollars per ton. The user may wish to change the standard assumptions EEA recommends for these items.

It is also possible to model other regulations such as a prohibition on residual fuel oil use in a region or a carbon tax on fossil fuels.

New Powerplants

All peaking plants built in the model are assumed to be gas/distillate turbines. Other plants can either be specified by type in the PLANTS file or as plants whose fuel type is determined through economic competition. Typical scenarios for new powerplant capacity include specification by type for all announced plants plus a certain number of unannounced hydro/renewable plants. The remaining capacity is determined in the

model by an economic competition between coal and gas. For this economic competition a number of assumptions may be specified including:

- types of plants for which competition will be allowed
- capital cost and escalation factors for new plants evaluation period, expected utilization rate, capital recovery factor
- logic for determining expected gas prices (e.g., historical extrapolation, perfect foresight)
- adjustments for institutional factors

The output of this step is the fraction of capacity in each region for each year that will be gas.

4. NATURAL GAS TRANSPORTATION AND DISTRIBUTION

4.1 Introduction

There are two major components in the Energy Overview Model's representation of natural gas transportation and distribution:

- The EEA Pipeline Network Model, which simulates transmission line capacities and expansions, solves for flows along pipeline corridors, and determines prices at various nodes, and
- The T&D rates Model, which tracks supply portfolios, calculates cost of service and determines rates.

The former may be thought of as primarily a "physical flows" model while the latter is primarily a "financial" model. Each component is discussed below.

4.2 Gas Pipeline Network Model

The Network Model characterizes pipeline capacities and transmission costs between "nodes" or physical delivery points in the U.S. and Canada. The Network Model uses a non-linear optimization algorithm to determine the pattern of gas flows that minimizes delivered gas prices at each node. These gas flows are limited by capacity and may be made subject to contract minimums. A unique feature of the EEA Gas Pipeline Network Model is its simulation of pipeline capacity expansion decisions

and the resulting impacts on pipeline rate bases. The user may specify potential pipeline projects including their capital cost, fuel losses and rate treatment and allow the model to decide when conditions are right for new capacity to be added.

Structure of the Network Model

The U.S. and Canadian natural gas transmission system is represented by approximately 60 "nodes". These are illustrated in Figure 4-1, which contains a map of the nodes and a legend describing the nodes. Nodes at which gas enters the system will have a description of the source under the heading "SUPPLY" and those at which gas is consumed will have a description of the sink under the heading "DEMAND". For instance, node "N1" is the demand node for the New England states. For some nodes, such as "N32" and "N39", gas neither enters or leaves the network system; such a node is a transshipment point or hub.

As can be seen from Figure 4-1, some EOM demand regions are split into more than one node in order to better represent the relationship of gas supply and demand to the physical pipeline system. For example, Demand Region 4 is split into "N8" for North Carolina, South Carolina and Georgia; "N10" for Florida; and "N11" for Mississippi, Alabama and Tennessee. The factors used to allocate regional demand among the nodes differ by sector. Some Hydrocarbon Supply Model regions also are split into more than one node. An example is the Appalachia Region for which production in New York is put into "N4" and production in other states into "N6".

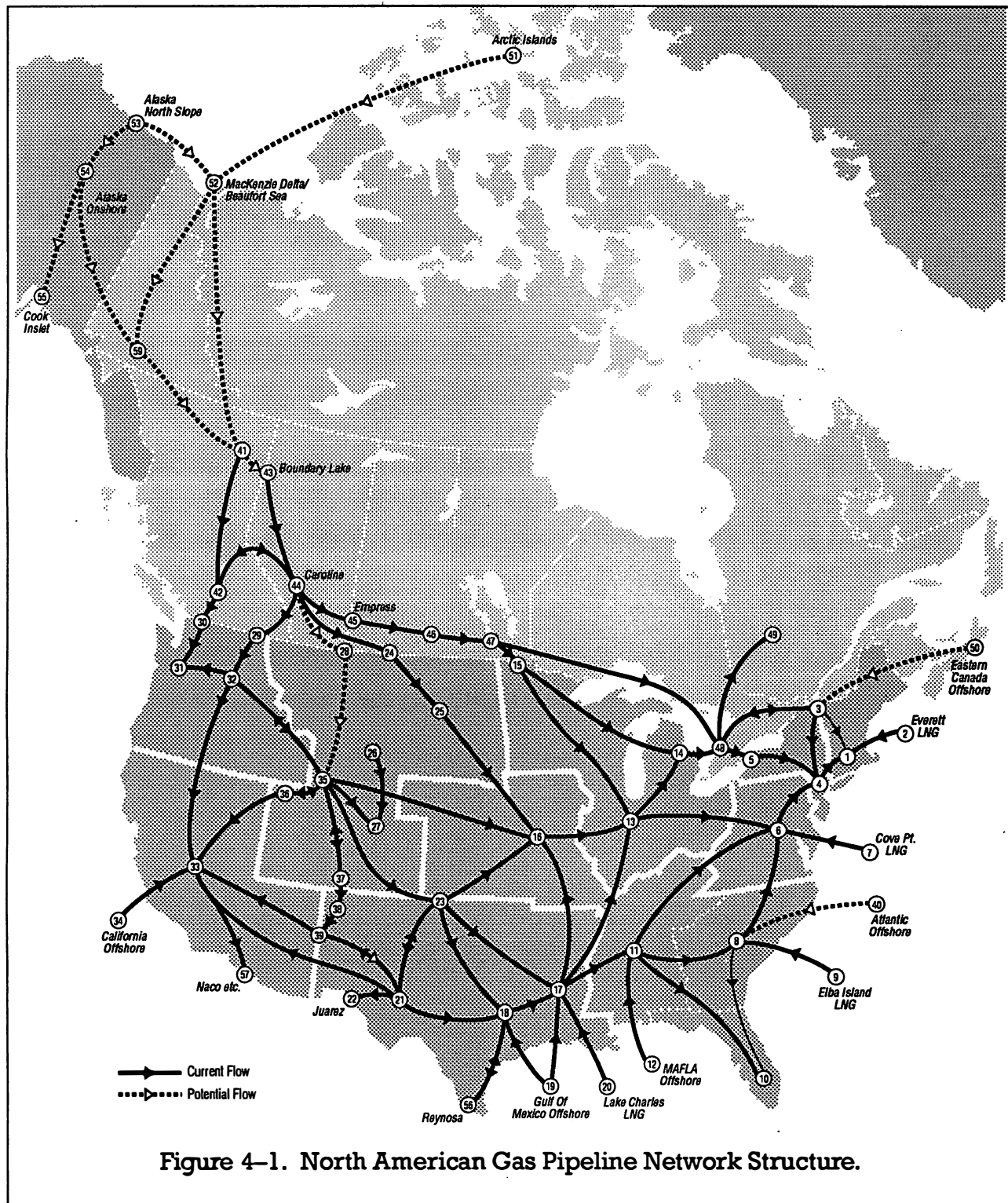
Flows between the nodes are characterized by "corridors" or "arcs", representing the composite of one or more actual pipeline systems. For any given year of an EOM simulation, each corridor has a maximum daily capacity in million cubic feet per day (MMcfd) and an assumed maximum annual capacity, which is computed as the daily capacity times 365 days times the maximum feasible load factor. The maximum feasible load factors are based on the demand and storage characteristics of the markets served by the corridor and may change over time.

The cost of moving gas along any corridor is represented in terms of dollars per Mcf charge

and a percent shrinkage factor. These transmission costs are generally 100 percent load factor rates. The rates may change as new capacity is added to the corridor. Depending on the assumptions used in the EOM simulation, the cost of new pipeline capacity may be "rolled in" to existing rates or priced "incrementally."

Solution for Flows and Prices in the Network Model

There typically will be several trial solutions of the Network Model in a simulation year as the entire EOM is equilibrated. The Network Model is solved on an annual basis with gas demand fixed from the previous iteration of the



demand models.¹ Production from each supply node can vary to up to approximately 96 percent of deliverability. As production in a region increases as a percent of deliverability, so does the average annual spot price for that region. The model seeks to minimize the cost of gas at each node by determining the amount of

gas produced in each supply node and the routes along which gas is transported. The re-

¹ The Network Model may also be solved in a "standalone" mode outside of the EOM. In such cases, the model can be solved monthly. It is also possible to solve the Network Model using demand functions or curves instead of fixed quantities.

Lower-48 Nodes			
NODE	NAME	SUPPLY	DEMAND
N1	NEW ENGL	—	ME, NH, VT, MA, CT, RI
N4	NY/NJ	Appalachia: NY	NY, NJ
N6	MID ATLANTIC	Appalachia: South	PA, DE, MD, VA, WV, KY
N8	SO ATL	—	NC, SC, GA
N10	FLORIDA	MAFLA – Florida	FL
N11	SO. EAST	MAFLA – MS/AL	MS, AL, TN
N12	NORPHLET	Norphlet	—
N13	MIDWEST	Midwest / Appalachia: Ohio	IN, IL, MI, WI, MN, OH
N16	CENTRAL	—	MO, IA, NE
N17	SO. LA	LA Gulf Onshore	AR, LA
N18	E. TEXAS	NE. TX / NO. LA & TX Gulf Onshore	E.TX
N19	Gulf Of Mexico	Gulf Of Mexico	—
N21	W. TEXAS	Permian Basin	W.TX, E.NM
N23	MID-CONT	Mid Continent	KS, OK
N25	GT PLNS Coal Gasification	Great Plains Coal Gasification	—
N26	HSM WL	Williston Basin	—
N27	MOUNTAIN	—	CO, UT, WY, MI, ND, SD
N31	PAC NW	Pacific: OR, WA	OR, WA, ID
N32	NPC / PGT	—	—
N33	SO PAC	Pacific: CA, AZ, NV	CA, AZ, NV
N34	HSM LO	Pacific Offshore	—
N35	OPAL WY	Rockies (HSM FR)	—
N36	HSM OV	Overthrust Belt	—
N37	HSM SJB	San Juan Basin (N)	—
N38	EPNG/SJ	San Juan Basin (S)	W.NM
N39	EPNG/TW	—	—
N40	Atlantic Offshore	HSM AO	—
Canadian/Alaska Nodes			
NODE	NAME	SUPPLY	DEMAND
N41	BC (N)	HSM BC	—
N42	BC (S)	—	BC
N43	Boundary Lake	—	—
N44	Caroline	HSM ASM	Alberta
N45	Empress	—	—
N46	Saskatchewan	—	Saskatchewan
N47	Manitoba	—	Manitoba
N48	Ontario	—	Ontario
N49	Quebec	—	Quebec
N50	Eastern Canada	HSM EC	Atlantic
N51	Arctic Islands	HSM ART	—
N52	Mack / Beaufort	HSM NWC	—
N53	Alaska North Slope	HSM AKO	—
N54	Alaska Interior	HSM AK	—
N55	Alaska Cook Inlet	HSM AKO	Alaska

Canadian Imports	
NODE	IMPORT LOCATION
N3	Phillipsburg / Cornwall
N5	Niagara
N14	St. Clair
N15	Emerson
N24	Monchy
N28	Wild Horse
N29	Kingsgate
N30	Huntingdon

Mexican Border Points	
NODE	IMPORT LOCATION
N22	Juarez
N56	Reynosa
N57	Naco etc.

LNG Imports	
NODE	TERMINAL LOCATION
N2	Everett
N7	Cove Point
N9	Elba Island
N20	Lake Charles

Figure 4–1 (cont'd).
Network Nodal Structure

sults of the solution process are:

- production at each supply node
- delivered-to-pipeline prices at each supply node
- flows through each corridor
- marginal and average prices at each transshipment and demand node

The Network Model uses a nonlinear optimization algorithm to solve for flows and prices. This is an iterative procedure which relies on linear approximations of the differentials of key relationships to develop successive guesses.

Capacity Expansion in the Network Model

The capacities of the pipeline corridors change through the model simulation. These changes are typically a combination of 1) pre-specified expansions for near-term projects already begun or planned and 2) endogenously determined longer-term generic expansions added by the model as needed. In all cases the expansion are entered into the model through the "Pipeline Expansion File" which includes the following variables for each project:

- name and project number
- origin and destination node
- predecessor project number (if any)
- earliest build date
- latest build date, if any
- total capacity in MMcfd, minimum increments in MMcfd
- design load factor in percent
- minimum load factor in percent, representing long-term contract commitments
- capital, O&M costs in dollars
- fuel losses as percent
- rate treatment (rolled-in vs incremental)
- years delay between economic viability and construction

If the fourth and fifth items (earliest and latest build dates) are the same, the model treats the project as pre-specified and does not do an economic test of its viability. It is simply built on the specified date. If the earliest build date

is different from the latest build date, say 1996 *versus* 2000, the model does an economic test on that project in each of the intervening years. If the project is not built by the latest build date, the Network Model automatically will build it in that year. If the latest build date is specified as "9999", the project will be built only when economically viable.

The most important test for economical viability in the model is that the transportation cost of the project be no greater than the expected price difference between destination and origin nodes after the project is built and operated at its design load factor. One way of determining this would be to re-solve the Network Model with the expansion added to determine the resulting post-expansion price difference. However, this approach would be computationally very inefficient given the large number of potential expansions that need to be tested each year. Instead, the Network Model uses an algorithm in which the supply and demand elasticities are "aggregated" at the origin and destinations of the project and the price impacts of building and operating the potential project at its design load factor determined analytically without re-solving the network.

Several user options in the model may be used to simulate the degree of risk that the owners of the pipeline would be willing to bare when making the expansion decision. These options include the amount by which the price differential must exceed new transport rates, the use of incremental rates rather than rolled-in rates for the economic test, the design load factor used in the test, and the time delay between when the project is economic and when it is constructed.

4.3 T&D Rates Model

Although the T&D Rates Model focuses on the role of pipelines as both merchants and transporters of gas, the model also is responsible for simulating gas production and gas distribution to final end-users. The model maintains the master account of gas supplies deliverable to end-use markets in the current period and performs the core accounting functions for reserve production and depletion. The model simulates the distribution of gas from the city-gate to end-users by means of an aggregate local distribution company (LDC) in each demand region. Revenue requirement accounts are maintained for each LDC to set distribution

margins by end-use sector, with margins and burnertip gas prices differing by demand region. LDC's themselves may offer end-users both sales service and transportation of gas purchased on the spot market.

An important element is the model's simulation of pipelines in their roles as both merchants and transporters of gas. Model pipeline manage their long-term supply planning to account for growth of transportation volumes on each system. They may release gas from long-term contracts for spot market sales and will offer transportation services to distributors and end-users under a mix of rates keyed to the quality of the service. Transportation margins are based on cost-of-service with an explicit simulation of the potential for rate discounting due to market pressures.

These processes are simulated by a structural design which explicitly represents these key factors:

Inventory of proven reserves, both under long-term contract and uncommitted (i.e., spot market gas)

- Schedules for gas deliverability, or the physical production capacity of reserves
- Terms and conditions in gas purchase contracts
- Impact of market conditions on the supply strategies of pipelines and distributors
- Costs of service and margin allocations to customer groups

Cost-of-service and reserve accounts are maintained by thirteen pipeline groups as shown in Figure 4-2. Distribution accounts are maintained for 10 composite distribution companies, one for each EOM demand region.

Gas Supply Accounting

The model begins each forecast period with base-year values for reserves committed to long-term contract to pipeline, distributors and end-users. Throughout the forecast period, the accounting system tracks deliverability from these reserves, the production of gas, and the acquisition of new gas supplies. Associated with each cell in this accounting structure are terms and conditions of gas purchase contracts which influence prices paid at the wellhead and the purchase obligations of the buyer. The accounting system also tracks gas supplies not committed by contract to any buyer (uncommitted reserves). Such uncommitted reserves are in many cases being marketed by producers and sold on the spot market. The accounts track deliverability from these reserves and their production for spot sales.

Associated with each block of gas supplies are these physical, regulatory, and contract parameters:

- Remaining reserves
- Deliverability
- Year proven as reserves (vintage)
- Price control status

No.	Model Pipeline	Major Pipelines Included	No.	Model Pipeline	Major Pipelines Included	No.	Model Pipeline	Major Pipelines Included
1	El Paso	El Paso Transwestern	5	Columbia	Columbia / Col. Gulf Texas Gas Texas Eastern Algonquin Consolidated	9	Northern Natural	Northern Natural Panhandle Eastern Trunkline
2	Pacific	Pacific Gas Transmission — All other Canadian sales of gas directly to distribution companies	6	Natural Gas Pipeline	NGPCA Mississippi River	10	ANR	American Natural Resources
3	Mountain	Colorado Interstate Mountain Fuel Northwest Pipeline	7	Tennessee	Tennessee East Tennessee MidWestern National Fuel Supply	11	NW Central	Northwest-Central (Williams) Kansas-Nebraska
4	United	United Southern Natural Florida Transmission Sea Robin Arkla	8	Transco	Transco	12	Intrastate	Total Intrastate Volumes
						13	California	Kern River

Figure 4-2. Model Pipeline Groups For Rate Accounting

- Contract terms
 - Price provisions
 - Daily contract quantity (buyer take requirement)

The T&D Rates Model uses algorithms specific to each region and type of gas for evaluating peak production capacity and deliverability decline rates. A key feature of the formulation is that deliverability is calculated as a function of cumulative gas production, not a function of time. What this means is that future deliverability of gas is influenced by prior market conditions and production levels.

A variety of pricing options and algorithms are provided as a user-specified input with model. Most model scenarios assume that new long-term gas contracts will be market responsive, that is, based on spot prices with a premium of a specified amount or percent.

Import and Supplemental Gas Supplies

In addition to Lower-48, Alaskan and Canadian wellhead supplies, the T&D Rates Model tracks the availability of import and supplemental gas supplies. This component of the model is designed to allow a significant degree of flexibility in introducing both current and future gas supply sources to any of the regional demand markets via the pipeline system. The model tracks four categories of import and supplemental supply:

- Mexican gas imports (or exports)
- Liquefied Natural Gas (LNG) imports
- Synthetic and Substitute Natural Gas (SNG)
- An "open" category to be defined by the user for speculative gas supplies not explicitly covered in the Hydrocarbon Supply Model

The gas supplies available in these categories can be constructed from up to 12 separate, user-specified supply sources including volumes to be supplied from each supply source and assumptions regarding price. In the case of LNG it is also possible to specify a "supply curve" which relates the quantity of imports at each LNG terminal to the gas prices in the EOM.

Supply Planning

Three elements of supply planning are simulated in the model for pipelines, distribution companies and end-users.

Pipelines

The rapid evolution of gas transport markets has placed pressures on the pipeline industry to adjust its supply planning to a smaller role as gas merchants. Pipeline groups in the model respond to this pressure by comparing the level of future sales and system deliverability needed to sustain it. A set of user-inputs (called the supply acquisition strategy) are used to simulate this process.

Distributors

The model also simulates important aspects of distributor supply planning strategies. LDC's in the model obtain a mix of gas from pipeline suppliers and direct (LDC) purchases on the carriage market. This framework is a portfolio approach to citygate supply management which is evolving for gas distributors. LDC's in the model fill their roles as supply planners by re-evaluating citygate supply portfolios as market conditions change. First, distributors may change the mix of pipeline and transport supplies in the portfolio. Second, to hedge against the uncertain availability of spot supplies, LDC's can sign long-term contracts with producers to reduce the risks associated with the spot gas element of the portfolio. Third, LDC's may adjust the mix of transportation service by reserving firm transportation capacity to ensure the capacity to deliver. All of these decisions affect the blend of wellhead prices and transportation costs in the core-market portfolio and are part of user-inputs of the supply acquisition strategy.

End-users

The third element of supply planning in the model concerns end-users. The most important element of this is the contract status of new electric generating plants. For most scenarios it is assumed that new electric power generators — including industrial cogenerators and gas-fired combined cycle units in the electric utility sector — will sign long-term supply contracts and will transport gas under firm transportation agreement. Different assumptions may be set by scenario.

Pipeline and Distributor Costs of Service

The T&D Rates Model estimates transmission costs on each of the thirteen model pipeline groups and distribution costs for one aggregate LDC in each of the 10 Federal regions. The algorithms for setting margins are cost-based in following the concept of utility costs of service. The costs are then allocated to the services provided by the pipeline or distributor to set margins. Market pressures and regulatory structures are allowed to determine the recovery of these costs. A key aspect of the model is its ability to provide outputs on the financial implications to the pipeline industry of the FERC decision to permit selective discounting of transport rates.

Transmission Costs

The transmission costs of service are developed for each model pipeline group from the aggregate pipeline financial statistics published annually by the Energy Information Administration (EIA). The underlying cost of service algorithm estimates year-to-year changes in the overall non-gas costs of pipeline operations based on the following components:

- Additions to rate base from construction forecast in the Network Model
- Fixed costs such as depreciation and return on rate base
- Fixed and variable operation and maintenance (O&M) costs
- Variable costs for compressor fuel which change both with volume and the cost of gas

This approach was taken, rather than the use of fixed pipeline tariffs, to permit a realistic response to costs of service to changes, system throughput and compression costs. Hence, if the volume of gas throughput (sales plus transportation) falls, the cost of some components of pipeline operations are reduced. Per-unit costs, however, will increase because the volume over which total costs are recovered will fall more rapidly.

After evaluating the cost of service for each pipeline group, the model allocates these costs between the sales and transportation services offered to customers. The allocation assigns cost recovery to sales and transport margins based on the mix of each pipeline's merchant

and transport services. As sales volumes decrease over time on a model pipeline, the share of fixed costs to be recovered from sales also decreases.

After allocation of costs, the model pipelines establish a structure of differential rates for differing classes of service. This may be done using Modified Fixed Variable (MFV) or Straight Fixed Variable (SFV) procedures. The transmission margin included in pipeline resale rates is assigned on a fully-allocated basis, meaning that the costs allocated to this service will be fully recovered in providing the service. Pipelines also maintain separate firm and interruptible rates applicable to transportation for distributors and end-users. Firm rates represent the reservation charge applied to firm transportation capacity. Interruptible rates are generally set at 100% load factor derivatives of firm rates. While the pipeline rate structure is cost-based, competitive forces and market pressures may prevent pipelines from fully recovering these costs.

Transportation Rate Discounting

An important feature of the model is its explicit representation of market pressures and their potential impact on pipeline margins. Pipelines are exposed to market risks in two ways. First, the model allows margins on transportation to distributors to be reduced below full-cost recovery to represent the potential discounting pressures of inter-pipeline competition. Second, the FERC structure of ceiling and floor rates for transportation is intended to give pipelines both the incentive and a regulatory approved mechanism to discount interruptible transportation in order to maintain throughput to price-sensitive markets. The model provides internal logic to solve for the pressures on transport margins in these markets. For example, when spot market gas prices rise as the current excess of deliverability is worked off, pipelines may not be able to recover their full margin costs in price-sensitive markets where many end-users may switch to alternate fuels. The model can allow pipelines to discount margins selectively in these markets to retain load.

Under EOM simulation of the Order 436 regime, costs not recovered due to discounting were absorbed by pipelines in their "bottom line" and not passed on to sales and firm trans-

port customers. The resulting revenue under-recovery was reported by the model as a key financial impact parameter. Alternatively, it is possible to set up scenarios wherein all or part of revenues lost due to discounted rates are passed on to sales and firm transport customers. This might better represent the emerging regime under Order 636 in which all fixed costs are allocated to firm customers and the firm transportation rights are auctioned to interruptible users on a periodic basis, i.e. actual firm rates depend on cost offsets from revenue received for interruptible service.

Distribution Costs

Cost-based distribution margins are developed in the model from considerations of revenue requirements by the aggregate distribution company in each demand region and the allocation of margin costs by end-use sector. The treatment of distribution costs differs somewhat from that described above in that no attempt is made to track component costs of distribution companies. Given the large number of distributors and the diversity among investor-owned, municipal, and combined gas-electric utilities, the base year revenue requirements and allocations by end-use sector are developed from state-level data published by EIA. The data are used to infer revenues and the allocation of costs by end-use sector, and are verified by comparison to the more detailed information available for major gas utilities in the Uniform Statistical Reports published by the American Gas Association.

The revenue requirement of each model LDC is the total (non-gas) costs of the distribution system to be recovered annually from end-use customers. The margin structure of the LDC is the set of margins by end-use sector which recover these costs. For example, cost-of-service studies show that residential customers cause gas utilities to incur higher costs per unit of sales because of their temperature-sensitive load profiles (high winter consumption) and relatively small annual volumes. However, policy and political judgments at the state level may modify the allocations in cost-of-service studies — e.g., public law in California mandating the availability of "lifeline" rates. The margins represent the outcome of cost-of-service studies and ratemaking practices at the state level which set average unit margins by customer class. These margins are then adjusted

over the forecast period to maintain full cost recovery by the model LDC.

The structure for distribution costs in the model also provides a representation for the emergence on many distribution systems of transportation rates for end-users who have obtained their own gas supplies. With advent of open-access, industrial and electric utility customers in many regions of the country have purchased low cost spot gas supplies and arranged transportation through the pipeline and distribution system to their plant-gates. The model allows each regional LDC to establish separate transport rates to these end-use sectors and to consider revenues from end-user transport within its overall revenue requirements.

The transport rates are set using the concept of equivalent margin contribution (the non-gas margin component in the LDC sales rate), which currently is the most commonly-used method for establishing rates. Model LDC's may be allowed to "flex" these rates downward to maintain price-sensitive load as occurred in many regions of the U.S. during 1986. The model also provides options for exposing LDC's to market risks for recovery of distribution system costs, leading the lower rates of return and lower costs charged to price-sensitive end-users.

4.4 User Specifications

There are several options available in setting up scenarios for the Network and T&D Rates Models. Some of the important items are reviewed below.

New Pipeline Construction Options

The "Pipeline Expansion File" contains information on the potential pipeline expansion projects. These projects may be changed to simulate different Canadian import policies, U.S. regulatory cases or competitive market conditions.

Decision Logic for New Pipeline Construction

Items related to how decisions are made include the "cushion" in the price differential test; the use of incremental *versus* rolled in rates for the economic test, the design load factor used in the test, and the delay to operation once the test is past. These options may be set to simulate different regulatory or market environments.

Supply Portfolios

Various scenario items may be set to determine how LDCs and end-users design their supply portfolios and how pipelines react. The key variables are the degree of long-term contracts *versus* reliance on spot and the fractions of firm *versus* interruptible transportation services.

Gas Pricing Provisions

Assuming that new contracts are to be market responsive, the key input is the price premium paid over spot. Other provisions having gas prices tied to oil or coal prices or with fixed escalators may also be simulated for all or part of the market.

Rate Setting

Key items here include MFV *versus* SFV and the degree to which revenues lost due to discounting interruptible service are recovered from firm shippers (stated in Order 636 terms, how interruptible revenues offset firm costs).

Trends in Cost of Service

The cost of new capacity is included in the "Pipeline Expansion File", and may be changed to reflect technological advances that reduce construction costs or stricter environmental regulations that could increase costs. It is also possible to change other components in the cost-of-service calculation to reflect financial conditions, pressures to reduce cost from incentive rate regimes, higher labor productivity, and so on.

5. SOLUTION PROCEDURE AND PRICE DETERMINATION

5.1 Introduction

The purpose of this chapter is to explain the methodology used in the Energy Overview Model (EOM) to solve for natural gas prices and demands. This will include an explanation of the workings of the EOM's Seasonal Module, which balances supplies and demands on a monthly basis.

5.2 Overall EOM Logic Flow

The overall logic flow of the EOM operating in the Equilibrating Mode is illustrated in Figure 5-1. The simulation starts by initializing guesses for current year gas demands and the "marker gas price", i.e., the average annual Texas/Gulf Coast spot price. The Hydrocarbon Supply Model then is executed to determine drilling activity and reserve additions for that year. Together with reserves carried forward from previous years, this establishes total reserves and, thus, available deliverability from the U.S and Canada.

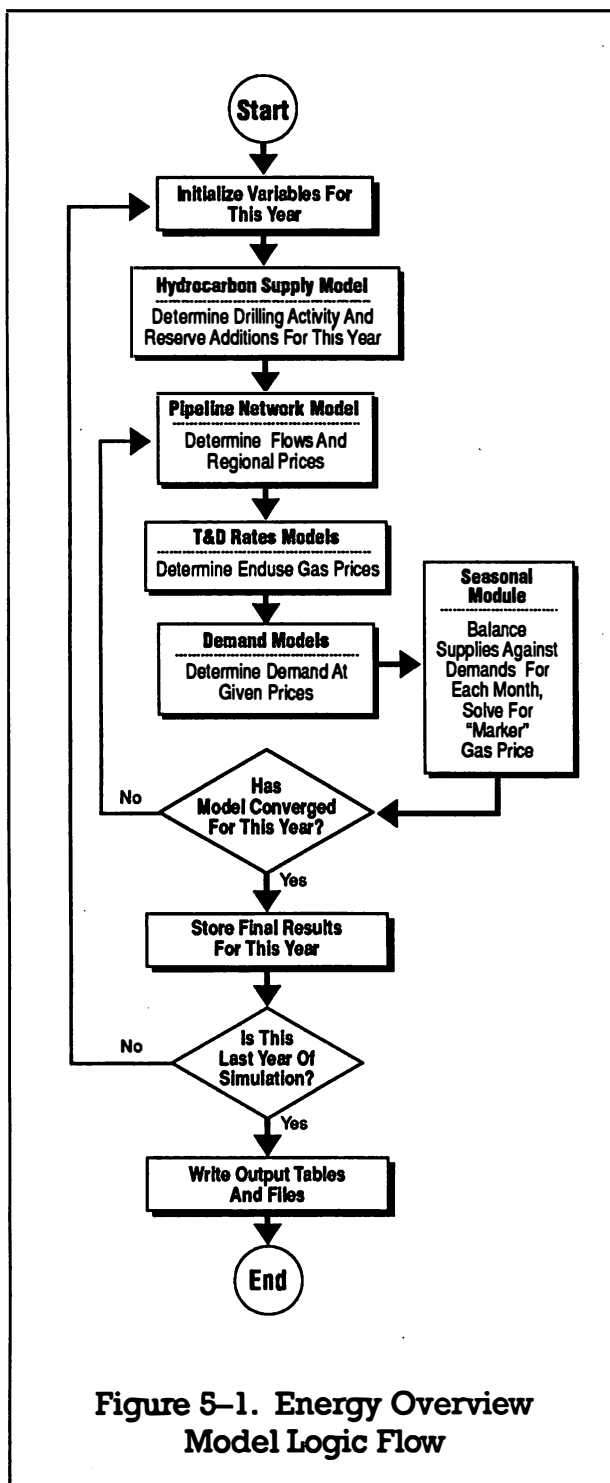


Figure 5-1. Energy Overview Model Logic Flow

The Gas Pipeline Network Model then is solved to determine flows and spot prices at each node given deliverability in each supply region, the initial guesses for demand and the marker gas price. This includes taking into account LNG and SNG volumes. Next the T&D Rates Model takes all gas volumes and prices and calculates end-use gas prices. This is the point where long-term *versus* spot premiums and other contract pricing term come into play.

The next step is to feed these end-use prices to the demand models to update the guess for natural gas demands (and other fuels). If gas demand volumes are within tolerances, the model has "converged" for that year, and the model proceeds to the next year.¹ If convergence has not been reached, the revised demand levels are put back into the Pipeline Network and T&D Rate Models to determine a new set of end-use gas prices, the Demand Models are run again with these new gas prices, and convergence is checked once more.

Part of this iteration process toward reaching convergence for the year is the operation of the Seasonal Module, which breaks out demand and supplies by month. The Seasonal Module determines storage patterns, the degree of monthly fuel switching (if any) needed to balance the market, the feasible wellhead capacity utilization rate and monthly prices in the Texas/Gulf Coast spot market. The monthly prices from the Seasonal Module are averaged into an annual average price, which is the basis for determining regional spot and long-term contract prices in the EOM.

5.3 Seasonal Module.

All parts of the Energy Overview Model operate on an annual basis with the exception of the Seasonal Module, which works on a monthly basis. The Seasonal Module takes results from other parts of the model, seasonalizes them and determines what should be a consistent set of monthly results. Through the iteration process, the monthly and annual results are made consistent with each other. What this means is

that annual gas demands are consistent with monthly fuel-switching patterns, annual spot gas prices are averages of monthly spot prices, and annual wellhead capacity utilization rates are consistent with monthly demand, production and storage patterns.

In brief, the procedure involves the following steps within each annual solution period (see Figure 5-2):

- 1) Annual demand for gas is computed by region and sector in the EOM demand models based on the current guess for the annual average spot gas wellhead price.
- 2) Based on the results from the EOM demand models for each within-year iteration, maximum potential demand for gas is computed in the Seasonal Module on a monthly basis using user-specified monthly profiles.
- 3) Annual volumes of Canadian imports, LNG, Alaskan gas, supplementals, storage gas and Lower 48 deliverability are converted in the Seasonal Module to available monthly supplies based on user-specified profiles.
- 4) Available monthly supplies are balanced against monthly potential demand in the Seasonal Module at a national level to determine takes on Lower 48 gas and the amount (if any) of potential demand that cannot be served. The monthly takes are aggregated into the annual wellhead capacity utilization rate (CU) which the EOM targets for the next iteration.
- 5) Prices are determined in the Seasonal Module for each month. The pricing logic assumes that in months in which all potential demand is being satisfied, prices are set by gas-on-gas competition as represented by an historically-fit pricing model based on take rates (i.e. when takes are low, gas prices are low). For months in which all potential gas demand cannot be met and some fuel switching is needed to balance the market, prices are set by using a monthly aggregate gas price/demand curves.
- 6) The final monthly prices are then averaged into an annual price which is used in the next iteration of the EOM.

Monthly Supply Profiles

Monthly national profiles are established within the Seasonal Module for all sources of gas. In most cases the monthly volume is found by

¹ The criteria are that 1) national demand is within one-half of one percent of supply 2) regional demands are within one percent of the previous iteration and 3) Lower 48 wellhead capacity utilization in the Network Model is within 0.001 of that desired by the Seasonal Module.

multiplying the annual quantity by monthly allocation shares which sum to one. For two sources of gas, Canadian imports and LNG, the monthly allocation is made by assuming that the historical patterns will hold up to certain level, and that a new, flatter pattern will exist for incremental quantities above that. For example, Canadian imports up to 1,400 bcf are assumed to have the historical, heavily winter peaking load shape. For amounts above 1,400 bcf per year, a flatter profile is assumed. For LNG the "cutpoint" is usually assumed to be 670 bcf per year, above which additional volumes enter with a flatter profile.

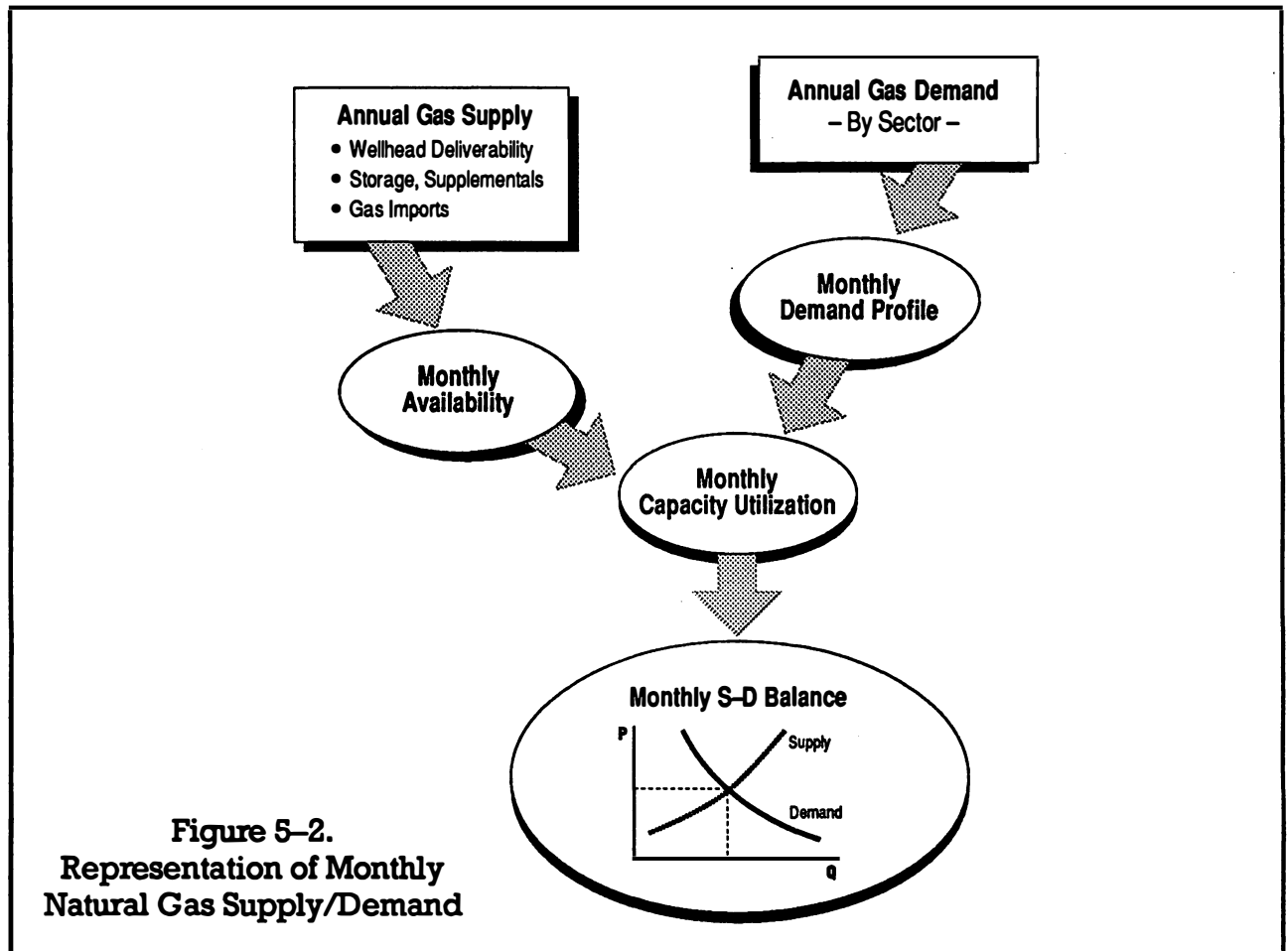
Patterns are also used for monthly gas storage injection and storage withdrawal. As with the other profiles, the basic patterns are based on recent historical averages. Within certain bounds, the storage profiles are allowed to change in the model to allow more injection in low price months and more withdrawal in high price months.

Lower 48 annual deliverability is tracked in the EOM in "cells" defined by vintages, NGPA/con-

tract categories, type of gas and pipeline group. Deliverability within each cell is calculated as a function of cumulative production. In the Seasonal Module, the sum of annual deliverability for all cells is divided evenly among the months. A ceiling is specified for the maximum amount of this monthly deliverability that can be produced in any month to take into account such factors as well maintenance shut-ins, freeze offs, transportation bottlenecks and market inefficiencies which make impossible the exact matching up of all available sellers with all available buyers. The monthly capacity utilization ceilings supplied by in the Seasonal Module typically results in an average of 96 percent takes on an annual basis. If the user wishes to run the model with a different maximum annual capacity utilization rate, the monthly capacity utilization ceilings in the Seasonal Module may be changed.

Monthly Demand Profiles

The Seasonal Module maintains monthly profiles for national demands by sector and mod-



fies these to reflect changes in demand composition and fuel switching. Separate monthly gas consumption profiles are determined for:

- electric utility steam units
- electric utility turbine units
- electric utility combined cycle units
- industrial boilers
- industrial non-boilers
- industrial cogeneration
- residential "conventional" demand
- residential "unconventional" (e.g., gas cooling) demand
- commercial conventional demand
- commercial "unconventional" (e.g., NGV) demand

The internal algorithms adjust the monthly profiles away from historical patterns by sub-sector (e.g., utility steam units, and industrial boilers) as fuel switching takes place. This reflects the preponderance of the initial losses in the winter months. In scenarios where fuel switching progressively increases, the additional fuel switching will be reflected as load loss in the shoulder, then summer months. The profiles for "normal" residential and commercial gas demand are not adjusted in the model from historical patterns over time. However, the profiles of "incremental demand" exogenously specified for natural gas vehicles or gas cooling will reflect the appropriate seasonal patterns.

Fuel Switching Effects

The effects of fuel switching are represented in the Seasonal Module by first calculating for each month the sub-sectoral "Historical Potential" gas market. This is the total annual gas and oil consumption times a historical monthly gas market share. (Note that this process is applied only to the fuel switchable markets — not to the residential or commercial sectors.) For industrial boilers, for instance, January gas consumption normally is 0.077 of the annual oil and gas consumption. This represents what consumption would be in January in the absence of any "abnormal" fuel switching.

The Seasonal Module also calculates a monthly gas consumption profile using the EOM demand models' annual gas consumption times the historical monthly gas profiles (i.e. is the monthly

profile as a fraction of gas-only consumption.) The Seasonal Module then takes the larger of the two values for each month and calls that the "Final Potential" monthly gas demand. The reason this is done is that the "Historical Potential" monthly gas consumption, which is based on historical gas market shares, might understate monthly gas demand in sub-sectors where the gas market share is growing over time.

The "Final Potential" demand is calculated by sub-sector and then added up to arrive at total potential gas demand each month. This is then compared against available supplies for each month. For Lower 48 gas, available supplies are the monthly deliverability times the maximum monthly capacity utilization ceiling. If monthly supplies exceed potential demand, it is assumed all demand is met and the Lower 48 monthly CU is solved for at a level below its ceiling. If potential monthly demand exceeds supplies, the wellhead CU is set to the monthly ceiling and the "market loss" is computed as the difference between potential demand and supply. When a gas market loss is needed to balance a month in the Seasonal Module, the loss is allocated by sub-sector based on the EOM demand model results. After each month is solved, the monthly CUs are then averaged to arrive at the annual CU that will balance the market.

Monthly Gas Prices

Monthly Gulf Coast onshore spot gas prices are computed in the Seasonal Module based on Lower 48 take rates and gas market losses, if any. (See Figure 5-3)

The pricing logic assumes that in months in which all potential demand is being satisfied, prices are set by gas-on-gas competition as represented by a historically fitted pricing model based on take rates (i.e. when takes are low, gas prices are low). For months in which all potential gas demand cannot be met and some fuel switching is needed to balance the market, initial monthly prices are set by using a monthly aggregate gas price/demand curves. In order to ensure a smooth transition between the two price setting logic methods, the Seasonal Module uses a weighting logic in the "transition zone".

In months in which some market is being lost (these are the months in which Lower 48 takes are at the CU ceiling), spot gas prices are calculated using the model's demand curves.

This is done by first calculating annual demand curves for each fuel switchable sub-sector (e.g., industrial boilers) relative to a Gulf Coast spot gas price. These curves are then converted to a percent of the sub-sector market. In the Seasonal Module the sub-sector curves are aggregated up to a monthly demand curve using the size of the potential gas market for each sub-sector for each month. Because the monthly curves in the Seasonal Module are generated from the EOM's demand models, shifts in gas markets due to economic growth, oil prices, fuel oil sulfur regulations, acid rain allowance costs etc. are properly accounted for in calculating monthly gas demand and prices.

5.4 User Specifications

The important user specifications for the models pricing logic are contained primarily in the Seasonal Module. These are explained below.

Lower-48 Capacity Utilization Ceilings by Month

Maximum fraction of monthly deliverability that can be taken each month. The average of these numbers determines the annual maximum take level toward which the model can solve.

Import and Alaskan Profiles

Monthly patterns for Canadian and LNG imports and Alaskan gas whereby one monthly profile is used below a certain cutpoint and another (usually flatter) profile above the cutpoint.

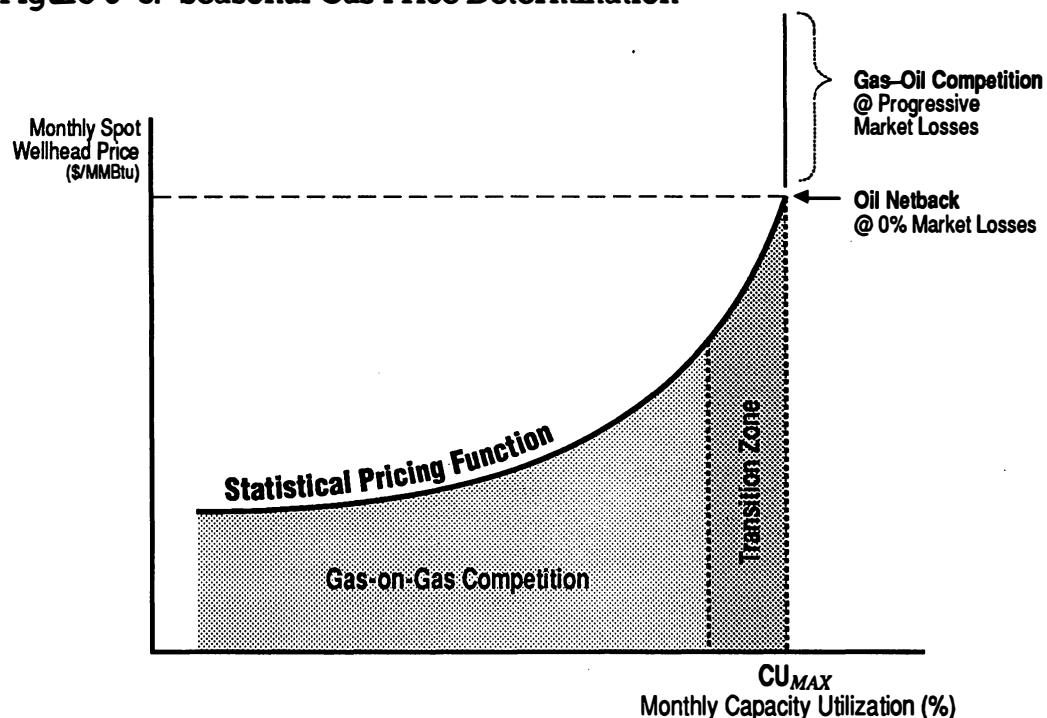
Demand Profiles

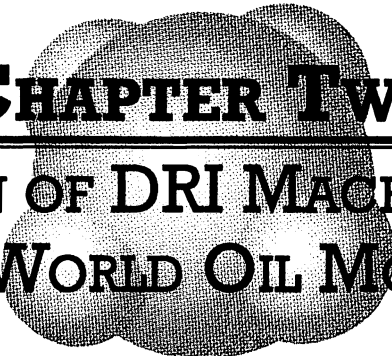
Monthly demand fraction for incremental gas markets such as gas cooling, natural gas vehicles.

Growth in Storage Capacity

Annual working gas capacity in trillion Btus. This is usually set to match growth in firm gas demand. Note that utilization of storage capacity is solved for by the model.

Figure 5-3. Seasonal Gas Price Determination





CHAPTER TWO

DESCRIPTION OF DRI MACROECONOMIC AND WORLD OIL MODELS

DRI/McGRAW-HILL WORLD OIL MODEL DOCUMENTATION

Introduction

The World Oil Model is the tool with which DRI/McGraw-Hill forecasts world oil supply/demand balances. Included among the outputs of the model are F.O.B. prices of crude oil, world oil supplies, and oil demands. The World Oil Model integrates the best available information and insights provided by a variety of very detailed, structural energy models of the United States, seventeen European nations, Japan, and Canada into its supply/demand framework. The oil demand equations in the model are adjusted to reproduce the forecast behavior of these country-specific structural energy models. Additionally, the macroeconomic inputs to the World Oil Model are taken directly from the forecasts prepared by DRI/McGraw-Hill's United States, European, Canadian, Japanese, Asian, Latin American, and Middle East and African macroeconomic services.

The model includes detail for crude oil and natural gas liquids production for 25 countries and regions and oil consumption for 11 separate countries or regions. For a complete listing of the items included as part of the World Oil Model forecast, please refer to the Retrieval Code Index in Appendix C, or in the latest International Oil Bulletin. The historical sources of this data are the U.S. Department of

Energy, International Energy Agency, Organization for Economic Cooperation and Development, as well as various country-specific and oil industry sources.

World Oil Model Structure

The DRI/McGraw-Hill World Oil Model was designed as a support tool for forecasting the world F.O.B. price of internationally-traded crude oil, oil supplies by producing countries, and oil demands by consuming countries, consistent with a balance in world oil markets. The model is comprised of econometrically estimated behavioral equations and accounting identities, and is simulated quarterly from the current quarter to the fourth quarter of 2005. The overall model structure is illustrated in Exhibit 1.

The simulation procedure generally employed is as follows:

- The model user provides a forecast "estimate" for the average F.O.B. price of internationally-traded crude oil. This price is termed an "estimate" since it is subject to analysis of the simulation results.
- World crude oil prices are translated in the model to real oil prices in local currency units using individual countries' exchange rates and inflation.
- Baseline projections for real national output, consistent with baseline world oil

prices, are adjusted endogenously to reflect the economic effects of changes in world oil prices from their baseline projections.

- Oil consumption for each country is modeled as a function of the country's real domestic economic output and its real domestic fuel price (which is based on local exchange rates and inflation).
- Oil stocks follow a seasonal pattern with adjustments upward or downward in response to trends in consumption levels and changes in desired inventory coverage, given relative movements in oil prices.
- Oil production for non-OPEC countries is adjusted endogenously in the model as a "lagged" response to changes in world oil prices relative to the DRI/McGraw-Hill base case. OPEC production for each member country remains an exogenous specification for the user to determine during post-solution analysis.
- The model represents world oil surpluses or shortfalls through increases or decreases in total non-Communist world oil

inventories, with the magnitude of world inventory changes used to establish the feasibility of the user's crude oil price and production estimates.

- Given the user's alternative oil price assumption (or other change in model specification), the user's subsequent analysis of the results will result in an acceptable simulation, or lead the user to further changes in crude oil prices, economic growth, exchange rates, inflation rates or other specifications as necessary to achieve a satisfactory world oil supply-demand balance.

The model endogenously determines oil consumption in the major 7 and "other" developed countries (comprising the OECD). Consumption forecasts for the non-OPEC developing nations and for OPEC countries are also forecast exogenously within the model. Base case production forecasts are entered exogenously for producing countries or groups of countries. Crude oil production for all non-OPEC countries then responds through a lag function to changes in oil prices. Exhibit 2 identifies the geographic detail included in the model.

EXHIBIT I
WORLD OIL MODEL STRUCTURE

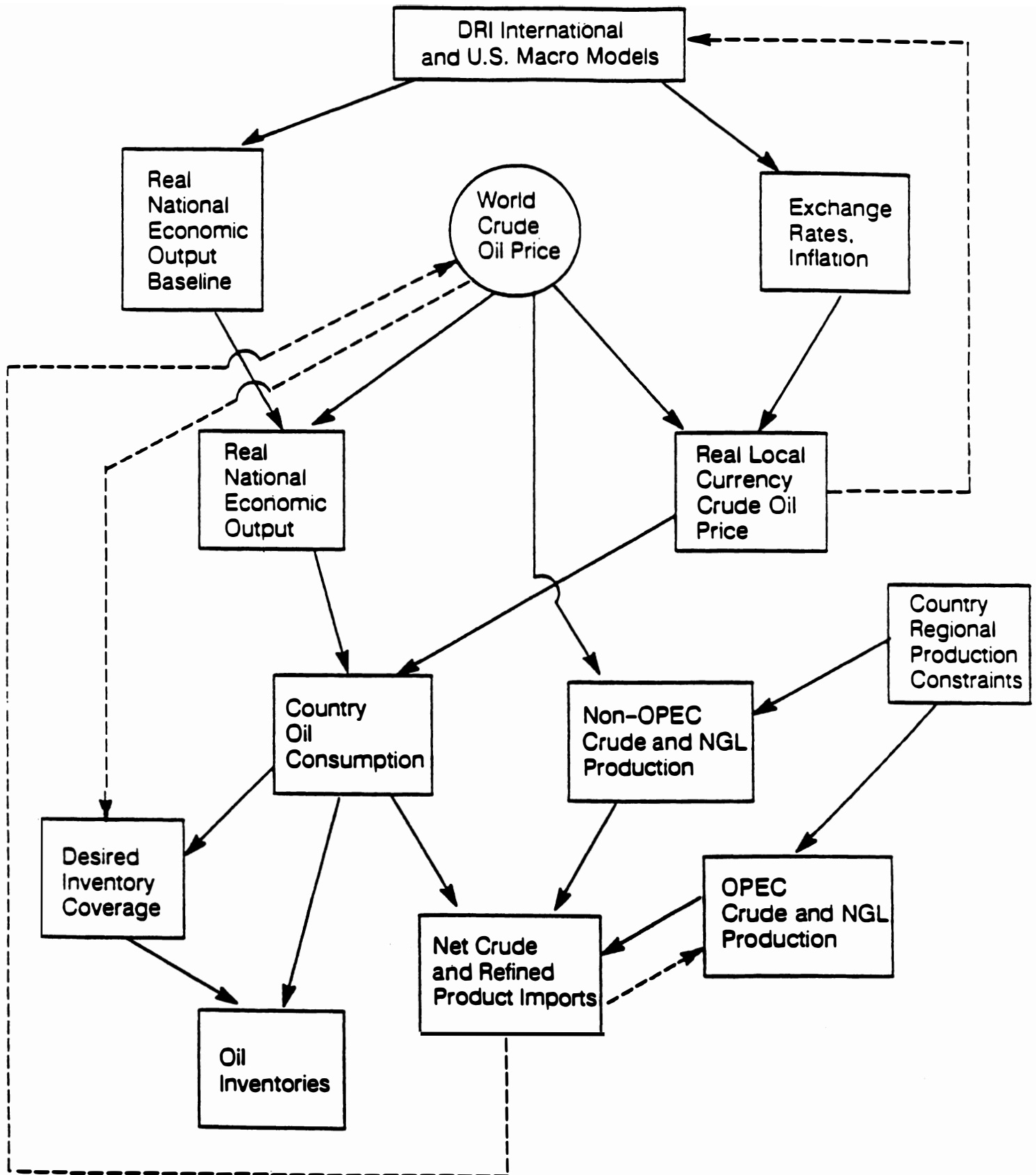


EXHIBIT 2
GEOGRAPHIC DETAIL

Oil Consumption

United States	Germany
Canada	Italy
Japan	OECD Except Major Seven
United Kingdom	Non-OPEC Less-Developed Countries
France	Communist Areas

Crude Oil Production

United States	Gabon
Canada	Saudi Arabia
Japan	Kuwait
United Kingdom	Iran
France	Iraq
Germany	United Arab Emirates
Italy	Qatar
Norway	Neutral Zone
Mexico	Venezuela
Other non-OPEC	Equador
Algeria	Indonesia
Libya	Communist Areas
Nigeria	

PHILOSOPHY AND PROPERTIES OF THE DRI MODEL OF THE U.S. ECONOMY

Since 1968, Data Resources has worked to advance the science of economic forecasting and policy analysis and, in doing so, to deliver substantial information to business and government. The newest version of the DRI Model of the U.S. Economy remains firmly in this tradition by:

- Responding to the constructive criticisms of both economics and econometric models that have arisen during the 1980s with a new, robust tool;
- Offering users a choice of user-friendly technology environments—timesharing and personal computers—on which to use this tool;
- Rigorously checking all equation specifications, coefficients, and model simulation properties; and
- Backing this effort with an extensive program of documentation and professional support.

Because of the enormous complexity of the economy, an economic model is a necessity for business planning, government policy analysis, and academic instruction. Financial, spending, production, wage-price, and international trade decisions all feed into each other. Significant lags and leads complicate the understanding of these cause-and-effect chains, and hence make difficult the prediction of future behavior and the interpretation of current conditions. Model design must realistically incorporate this complexity but also support a reliable, user-friendly tool.

While the DRI Model covers a large number of variables, the investment DRI has made in the economic structure of the Model and in developing its new, convenient PC environment make this large Model easier and less costly to use on real, client-specific issues than competing, smaller models. There is no need to accept the shortcomings of smaller models: forecast insensitivity, insufficient sectoral detail, or crudeness in integrating scenario assumptions. We firmly believe a solid, large model is a cost saver because it, rather than the user, automatically performs many preparatory calculations and many reliable translations of aggregate outputs into firm- or sector-specific detail.

As any example, consider estimation of the impacts of the large-scale defense budget reductions proposed by Secretary Cheney in late 1989. Financial, industrial, and government clients need to interpret the impacts of the manpower and procurement cutbacks on the outlook for specific industries as well as the broad macroeconomic repercussions. The detailed structure of the Model greatly facilitates inputting these changes and then automatically, reliably produces the required, targeted outputs without any additional user effort.

The Federal budget details of the DRI model—separately identifying defense department payroll and materials purchasing—allows the user to easily and accurately inject the budgetary shift. In this case, it is clear that spending cuts concentrated on procurement as opposed to, for example, NATO personnel will have decidedly stronger impacts on specific durables goods industries in the U.S., will mean less for the U.S. trade balance, and will produce a sharper, quicker reduction in overall economic activity. Moreover, the careful weighting of specific final demands in the industrial production block of the model guarantees that a reliable answer will automatically be generated for each of sixty forecasted industrial production indexes (disaggregated to a 2- to 4-digit standard industrial classification code level). These changes will, in turn, generate reasonable shifts in detailed producer price indexes, filling-out the sales impact analysis.

Most smaller models would not recognize the difference between manpower and procurement expenditures or, even if such input details were recognized, they do not have the built-in output detail. The user must invent all the supportive analytical structures, crudely patch them onto the core model, and then hope that the missing interactions are insignificant.

The Model's Theoretical Position

Econometric models built in the 1950s and 1960s were largely Keynesian income expenditure systems that assumed a closed domestic economy. High computation costs during estimation and manipulation, along with the underdeveloped state of macroeconomic theory, limited the size of the models and the richness of the linkages of spending to financial conditions, inflation, and international developments. Since that time, however, computer

costs have fallen spectacularly; theory has also benefited from four decades of postwar data observation and from the intellectual attention of many eminent economists.

An Econometric Growth Model: The DRI Model incorporates the best insights of many theoretical approaches to the business cycle: Keynesian, neoclassical, monetarist, supply-side, and rational expectations. In addition, the DRI Model embodies the major properties of the long-term growth models presented by James Tobin, Robert Solow, Edmund Phelps, and others. This structure guarantees that robust long-run properties will temper short-run cyclical developments.

In growth models, the expansion rate of technical progress, the labor force, and the capital stock determine the productive potential of an economy. Both technical progress and the capital stock are governed by investment, which in turn must be in balance with post-tax capital costs, available savings, and the capacity requirements of current spending. Thus, for example, monetary and fiscal policies will influence the short- and the long-term characteristics of such an economy through their impacts on national saving and investment.

A modern model of output, prices, and financial conditions is melded with the growth model to present the detailed, short-run dynamics of the economy. In specific goods markets, the interactions of a set of supply and demand relations jointly determine spending, production, and price levels. Typically, the level of inflation-adjusted demand is driven by prices, income, wealth, expectations, and financial conditions. The capacity to supply goods and services is keyed to a production function combining the basic inputs of labor hours, energy usage, and the capital stocks of equipment and structures. The "total factor productivity" of this composite of tangible inputs is linked to accumulated expenditures on research and development. Prices adjust fully to gaps between current production and supply potential and to changes in the cost of inputs.

For financial markets, the model predicts exchange rates, interest rates, stock prices, loans, and investments interactively with the preceding variables. The Federal Reserve sets the supply of reserves in the banking system and the fractional reserve requirements for de-

posits. Private sector demands to hold deposits are driven by household disposable income, business cash flow, expected inflation, and by the deposit interest yield relative to the yields offered on alternative investments. Banks and other thrift institutions, in turn, set deposit yields based on the market yields of their investment opportunities with comparable maturities and on the intensity of their need to expand reserves to meet legal requirements; in other words, the contrast between the supply and demand for reserves sets the critical short-term interest rate for interbank transactions, the federal funds rate. Other interest rates are keyed to this rate, plus expected inflation, Treasury borrowing requirements, and sectoral credit demand intensities.

The labor market has three basic components. The supply of labor positively responds to the perceived availability of jobs and, albeit weakly, to the wage level. Demand for labor is keyed to the level of output in the economy and the productivity of labor, capital, and energy. Because the capital stock is largely fixed in the short run, a higher level of output requires more employment and energy inputs. Such increases are not necessarily equal to the percentage increase in output because of the improved efficiencies typically achieved during an upturn.

Wages, the price of labor, are adjusted to bring demand and supply into balance. Excess supply is obviously registered by a high unemployment rate, which reduces the rate of increase in wages. The expansion of wages in a fully employed economy is set by the growth in the expected value of output per hour: wages will increase more rapidly the greater the expected expansion rates of labor productivity and output prices. Tempering the whole process of wage and price determination is the exchange rate; a rise signals prospective losses of jobs and markets unless costs and prices are reduced.

Monetarist Aspects: The model pays due attention to valid lessons of monetarism by carefully representing the diverse portfolio aspects of money demand and by capturing the central bank's role in long-term inflation phenomena. The private sector may demand money balances as one portfolio choice among transactions media (currency, demand deposits, some savings deposits), investment media

(bonds, stocks, short-term securities), and durable assets (homes, cars, equipment, structures). Given this range of choice, each medium's implicit and explicit yield must therefore match expected inflation, offset perceived risk, and respond to the scarcity of real savings. Money balances provide benefits by facilitating spending transactions and can be expected to rise nearly proportionately with transactions requirements unless the yield of an alternative asset changes. Now that even demand deposit yields can float to a limited extent in response to changes in Treasury bill rates, money demand no longer shifts quite as sharply when market rates change. Nevertheless, the velocity of circulation (the ratio of money demand to nominal spending) is still far from stable during a cycle of monetary expansion or contraction. Thus the simple monetarist link from money growth to price inflation or nominal spending is therefore considered invalid as a rigid short-run proposition.

Equally important, as long-run growth models demonstrate, induced changes in capital formation can also invalidate a naive long-run identity between monetary growth and price increases. Greater demand for physical capital investment can enhance the economy's supply potential in the event of more rapid money creation and hence higher inflation. The yield on currency is fixed and the yield on demand deposits will only partially reflect added inflation, but physical capital is a near-perfect inflation hedge; a higher inflation economy can be a more capital-intensive economy with a greater productive potential. In the DRI Model, both prices and quantities can therefore change in response to monetary policy initiatives. If simultaneous, countervailing influences prevent an expansion of the economy's potential, however, the model will (within a decade) translate all money growth into a proportionate increase in prices rather than in physical output.

"Supply-Side" Economics: Since 1980, "supply-side" political economists have pointed out that the economy's growth potential is sensitive to the policy environment. They focused on potential labor supply, capital spending, and savings impacts of tax rate changes. The DRI Model embodies supply-side hypotheses to the extent supportable by available data, and this is considerable in the many areas that supply-side hypotheses share with long-

run growth models. These features, however, have been fundamental ingredients of our model since 1976.

Rational Expectations: As the rational expectations school has pointed out, much of economic decision-making is forward looking. For example, the decision to buy a car or a home is not only a question of current affordability but also one of timing; the delay of a purchase until interest rates or prices decline has become particularly common since the mid-1970s when both inflation and interest rates were very high and very volatile. Consumer sentiment surveys, such as those conducted by the University of Michigan Survey Research Center, clearly confirm this speculative element in spending behavior.

However, households can be shown to base their expectations, to a large extent, on their past experiences: they believe that the best guide to the future is an extrapolation of recent economic conditions and the changes in those conditions. Consumer sentiment about whether this is a "good time to buy" can therefore be successfully modeled as a function of recent levels and changes in employment, income, interest rates, and inflation. Similarly, inflation expectations (influencing financial conditions) and market strength expectations (influencing inventory and capital spending decisions) can be modeled as functions of recent rates of increase in prices and spending.

This largely retrospective approach is not, of course, wholly satisfactory to pure adherents to the rational expectations doctrine. In particular, this group argues that the announcement of macroeconomic policy changes would significantly influence expectations of inflation or growth prior to any realized change in prices or spending. If an increase in government expenditures is announced, the argument goes, expectations of higher taxes to finance the spending might lead to lower consumer or business spending in spite of temporarily higher incomes from the initial government spending stimulus. A rational expectations theorist would thus argue that multiplier effects will tend to be smaller and more short-lived than a mainstream economist would expect.

These propositions are subject to empirical evaluation. Our conclusions are that expectations do play a significant role in private sector

spending and investment decisions; but, until change has occurred in the economy, there is very little room for significant changes in expectations in advance of an actual change in the variable about which the expectation is formed. The rational expectations school thus correctly emphasizes a previously understated element of decision-making, but exaggerates its significance for economic policy-making and model building.

The DRI Model allows a choice in this matter. On the one hand, the user can simply accept DRI's judgments and let the model translate policy initiatives into initial changes in the economy, simultaneous or delayed changes in expectations, and subsequent changes in the economy. On the other hand, the user can manipulate the clearly identified expectations variables in the model, i.e., consumer sentiment, inflation expectations, and interest rate volatility. For example, if the user believes that fear of higher taxes would subdue spending, he could reduce the consumer sentiment index. Such experiments can be made "rational" through model iterations that bring the current change in expectations in line with future endogenous changes in income, prices, or financial conditions.

Theory As a Constraint: The conceptual basis of each equation in the DRI Model was thoroughly worked out before the regression analysis was initiated. The list of explanatory variables includes a carefully selected set of demographic and financial inputs. Each estimated coefficient was then thoroughly tested to be certain that it meets the tests of modern theory and business practice. This attention to equation specification and coefficient results has eliminated the "short circuits" that can occur in evaluating a derivative risk or an alternative policy scenario. Because each equation will stand up to a thorough inspection, the DRI Model is a reliable analytical tool and can be used without excessive iterations. The model is not a black box: it functions like a personal computer spreadsheet in which each interactive cell has a carefully computed entry and thus performs logical computations simultaneously.

Major Sectors

The DRI Model captures the full simultaneity of the U.S. economy, forecasting 1,200 concepts spanning final demands, aggregate supply, prices, incomes, international trade, in-

dustrial detail, interest rates, and financial flows. Chart 1 and Table 1 summarize the structure of the eight interactive sectors (noted in Roman numerals). The following discussion briefly presents the logic of each sector and the significant interactions with other sectors; full details appear in subsequent chapters.

Spending—Consumer: The domestic spending (I), income (II), and tax policy (III) sectors model the central circular flow of behavior as measured by the national income and product accounts. If the rest of the model were "frozen," these blocks would produce a Keynesian system similar to the models pioneered by Tinbergen and Klein.

Consumer spending is divided into three durable goods categories (autos and parts, furniture, and "other"); five nondurable goods categories (food, clothing and shoes, gas, fuel, and "other"); and eight service categories (housing, transportation, three household operation subcategories, medical, financial services, and "other"). In nearly all cases, real expenditures are motivated by real income and the price of a particular category relative to the prices of other consumer goods. Durable and semidurable goods are also sensitive to household net worth, current financing costs, and consumer speculation on whether it is a "good time to buy." The University of Michigan Survey of Consumer Sentiment monitors this last influence, with the index itself modeled as a function of current and lagged values of inflation, unemployment, and the prime rate.

Spending—Business Investment: Business spending includes six fixed investment categories (autos, office equipment, other producer durables, public utility structures, mining and petroleum structures, and buildings and other structures) and five inventory spending categories (farm, manufacturing, wholesale, retail, and "other"). Equipment and non-utility, non-mining, structures spending is determined by the effective post-tax capital costs, capacity utilization, and replacement needs. The cost terms are sophisticated blends of post-tax debt and equity financing costs (offset by expected capital gains) and the purchase price of the investment good (offset by possible tax credits and depreciation-related tax benefits). This updates the well-known work of Dale Jorgenson, Robert Hall, and Charles Bischoff.

Chart 1
Overview of the DRI/McGraw-Hill Model

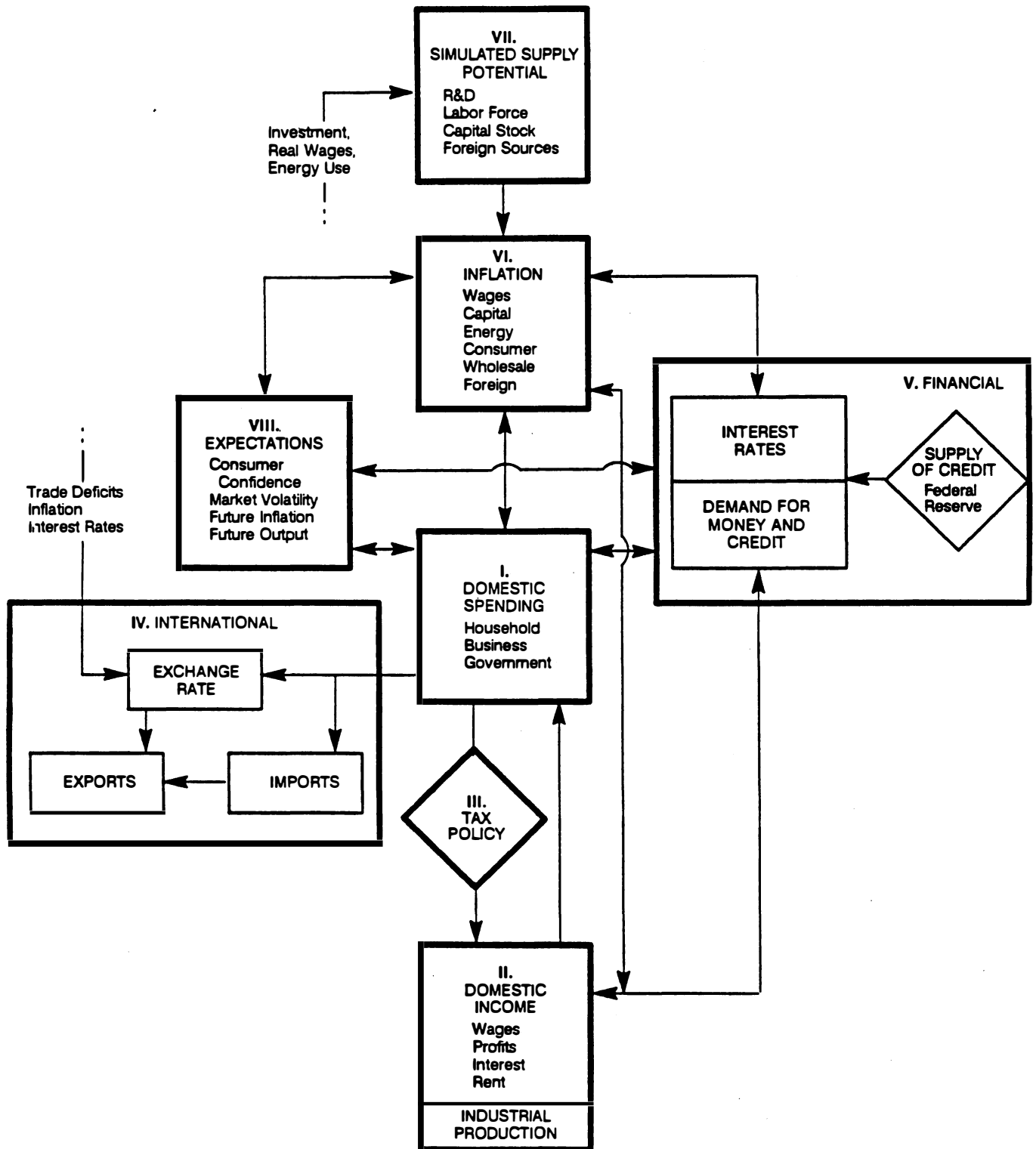


Table 1
Model Variables

Sector	Basic Behavioral (Stochastic)	Identities And Special Monitors	Exogenous	Total
I. Private Domestic Spending				
A. Consumption	17	32	6	55
B. Business Spending	7	43	23	73
C. Housing	12	22	8	42
D. Inventory Accumulation	9	17	1	27
II. Production and Income				
A. Wages	2	3	1	6
B. Corporate Profits & Depreciation ..	4	41	75 *	120
C. Industry Detail				
1. Production	61	98	4	163
2. Capacity, Operating Rates	1	2	1	4
3. Employment	28	7	0	35
D. Interest, Rent, Entrepreneurial, Misc	8	2	2	12
III. Government				
A. Federal	3	33	32	68
B. State and Local	11	15	6	32
C. Aggregates	0	18	1	19
IV. International Transactions (Goods & services, prices & quantities)				
A. NIPA & Census Exports & Imports ...	31	68	26	125
B. Exchange Rates, Foreign Interest Rates, Activity	1	7	7	15
C. Current Account (including Investment Income) and Net International Investment Position	7	19	14	40
V. Financial				
A. Monetary & Financial Aggregates ...		28	14	64
B. Interest Rates	22	8	3	33
C. Household & Mortgage Flow of Funds	10	9	1	20
D. Stock Market	4	2	0	6
VI. Inflation and Productivity				
A. Producer Prices	11	40	14	65
B. Deflators and CPI	33	51	6	90
C. Wages & Productivity	3	7	2	12
VII. Supply				
A. Nonresidential Capital Stocks	0 **	33	7	40
B. Labor Supply, Employment, & Hours .	4	2	2	8
C. Energy	4	12	13	29
D. Aggregate Supply	0	4	0	4
VIII. Expectations				
A. Consumer	1	0	0	1
B. Financial	1	3	0	4
IX. Population	0	0	8	8
X. Aggregates & Miscellaneous	4	27	9	40
Total	321	653	286	1260

* Includes 69 tax depreciation rates for calculating the book value of the capital stock.

** Investment spending is included in business spending (I.B.).

Given any cost/financing environment, the need to expand capacity is monitored by recent growth in national goods output. Public utility structure expenditures are motivated by similar concepts except that the output terms are restricted to electricity and gas utility output rather than total national goods output. Net investment in mining and petroleum structures responds to movements in real domestic oil prices and to the energy demands of the economy.

The fixed investment equations are more sensitive to changes in the economy than in pre-1985 models because of their new, Bischoff-based specification. Most noteworthy is the greater sensitivity to interest rates. The estimated structure, with a clear separation of output and capital cost influences into change and level components, has clearly enhanced the accelerator properties of the model. This, we believe, definitely improves its cyclical sensitivity but not at the expense of its long-run properties; its long-run properties remain robust because replacement needs are constrained to match the depreciation rates used to create corresponding capital stocks, and the capital stocks determine consistent estimates of capacity. These capacity measures, when contrasted with current and expected output, drive investment, wage, and price decisions.

Inventory demand is the most erratic component of GNP, reflecting the procyclical, speculative nature of private sector accumulation during booms and decumulation during downturns. The forces that drive the four non-farm stock categories are changes in spending, short-term interest rates and expected inflation, surges in imports, and changes in capacity utilization or the speed of vendor deliveries. Surprise increases in demand lead to an immediate drawdown of stocks and then a rebuilding process over the next year; the reverse naturally holds for sudden reductions in final demand. Inventory demands are sensitive to the cost of holding the stock, measured by such terms as interest costs adjusted for expected price increases and by variables monitoring the presence of bottlenecks. The cost of a bottleneck that slows delivery times is lost sales: an inventory spiral can therefore be set in motion when all firms accelerate their accumulation during a period of strong growth but then try to deplete excessive inventories when the peak is past.

Spending—Housing: Residential construction is typically the first sector to turn down in a recession and the first to rebound in a recovery. Moreover, the magnitude of the building cycle is often the key to that of the subsequent macro-economic cycle. This is as true today as in past decades, although changes in financial market regulation have altered this sector's behavior. Up until the 1980s, surges in housing were produced by "disintermediation," i.e., cyclical losses and gains of deposits at thrift institutions (which were bound by the Regulation Q deposit-yield ceiling) to alternative investment media as market interest rates rose or fell. With the removal of such ceilings, mortgage lenders—as well as homebuilders and buyers—can now obtain construction funds if they are willing to pay a competitive interest rate. Buyers are thus being priced out of the market by a high yield rather than rationed out by an absence of funds.

The housing sector of the DRI Model reflects this change, explaining new construction as a decision primarily based on the after-tax cost of homeownership relative to disposable income. This cost is estimated as the product of the median home price and the mortgage rate, plus operating costs and property taxes. "Lever variables" allow the model user to specify the extent to which mortgage interest payments and property taxes produce tax deductions that reduce the effective cost.

Due to the change in financial regulations, the equations for single- and multi-family housing are based only on data from 1978 through 1989. This brief estimation interval could potentially create problems for long-term forecasting except that the equations also include a careful specification of demographic forces. After estimating the changes in the propensity for specific age-sex groups to form independent households, the resulting "headship rates" were multiplied by corresponding population statistics to estimate the trend expansion of households. The housing equations were then specified to explain current starts relative to the average increase in trend households over the past three years. The basic phenomenon being scrutinized is therefore the proportion of the trend expansion in households whose housing needs are met by current construction. As noted earlier, a primary determinant of this proportion is housing affordability; another

significant ingredient is the gap between the actual stock of homes and the trend level of households. Actual construction spending in the GNP accounts is the value of construction "put-in-place" in each period after the start of construction (with a lag of up to six quarters in the case of multi-family units), plus additions, alterations, and brokerage fees.

Spending—Government: The last sector of domestic demand for goods and services, that of the government, is largely exogenous (user-determined) at the federal level and endogenous (equation-determined) at the state and local level. The user sets the real level of federal nondefense purchases of goods and services, defense purchases, transfer payments, and grants to state and local governments. The model calculates the nominal values through multiplication by the relevant estimated prices. Changes in interest payments are determined by changes in the debt (the current deficit) and changes in the average interest rate as debt is expanded or rolled over.

The presence of a large and growing deficit imposes no constraint on federal spending. This contrasts sharply with the state and local sector where legal requirements for balanced budgets mean that declining surpluses or emerging deficits produce both tax increases and reductions in spending growth. State and local purchases of goods and services are also driven by the level of federal grants (due to the matching requirements of many programs), population growth, and trend increases in personal income.

Production: The industrial production sector includes 60 standard industrial classifications (SIC). Production is a function of various cyclical and trend variables and a "generated" output term, i.e., the input-output (I-O) relationship between the producing industry and both intermediate industries and final demand. In other words, generated output terms are carefully constructed averages of the activity levels in the markets to which the industry sells. The cycle and trend variables correct for changes in I-O coefficients that are implied by the changing relationships between buyers and sellers. This structure guarantees a reliable transformation from the basic final demand indicators into detailed, market-specific production indicators. The model performs these calculations automatically during each

solve command, delivering immediately useful information for business planning without additional effort by the user.

Income: Domestic spending, adjusted for trade flows, defines the economy's value-added or gross national product. Because all value-added must accrue to some sector of the economy, the expenditure measure of GNP also determines the nation's gross income. The distribution of income among households, business, and government is determined in sectors II and III of the model.

Pre-tax income categories include private and government wages, corporate profits, interest, dividends, rent, and entrepreneurial returns. Each pre-tax income category except corporate profits is modeled as a function of wages, prices, interest rates, debt levels, and capacity utilization or unemployment rates. Profits are logically the most volatile component of GNP on the income side. When national spending changes rapidly, the contractual arrangements for labor, borrowed funds, and energy imply that the return to equity holders is a residual that will soar in a boom and collapse in a recession. The model reflects this by calculating wage, interest and rental income as thoroughly reliable near-identities (e.g., wages equal average earnings multiplied by hours worked) and then subtracting each non-profit item from national income to solve for profits.

Taxes: Since post-tax rather than pre-tax incomes drive expenditures, each income category must be taxed at an appropriate rate; the model therefore tracks personal, corporate, payroll, and excise taxes separately. Users may set federal tax rates; tax revenues are then simultaneously forecast as the product of the rate and the associated pre-tax income components. However, the model automatically adjusts the effective average personal tax rate for variations in inflation and income per household, and the effective average corporate rate for credits earned on equipment, utility structures, and R&D. With the exception of corporate profits and social insurance tax rates, state taxes are fully endogenous: the Model makes reasonable adjustments automatically to press the sector toward the legally-required approximate budget balance. The average personal tax rate rises with income and falls with the government operating surplus. Property and sales taxes provide the bulk of state excise

revenue and reflect changes in oil and natural gas production, gasoline purchases, and retail sales, as well as the government surplus. The feedback from expenditures to taxes and taxes to expenditures works quite well in reproducing both the secular growth of the state and local sector and its cyclical volatility.

International: The international sector (IV) is a critical, fully simultaneous block that can either add or divert strength from the central circular flow of domestic income and spending. Depending on the prices of foreign output, the U.S. exchange rate, and competing domestic prices, imports capture varying shares of domestic demand. Depending on similar variables and the level of world gross domestic product, exports can add to domestic spending on U.S. production. The exchange rate itself responds to international differences in inflation, interest rates, trade deficits, and capital flows between the U.S. and its competitors. In preparing forecasts, DRI's U.S. Economic Service and the World Service collaborate in determining internally consistent trade prices and volumes, interest rates, and financial flows.

The latest Model incorporates refinements in three key areas of the foreign sector. First, additional export and import details for business machines have been added as a natural counterpart to the addition of the office equipment component of producers' durable equipment spending. The business machines detail allows more accurate analysis because computers are rapidly declining in effective quality-adjusted prices relative to all other goods, and because such equipment is rising so rapidly in prominence as businesses push ahead with new production and information processing technologies.

Second, investment income flows are now explicitly modeled. The stream of huge current account deficits incurred by the U.S. during the 1980s, and the prospects for continued large deficits in the years ahead, have important implications for the U.S. investment income balance. As current account deficits accumulate, the U.S. net international investment position and the U.S. investment income balance deteriorate. While the DRI/McGraw-Hill Model has always included detail on merchandise trade flows, the growth in the U.S. foreign debt now requires comparable detail on investment income flows and the corresponding balance sheet

items. U.S. foreign assets and liabilities have therefore been added to the model, with the current account deficit determining the path of the net investment position. Investment income flows are modeled as rates of return on the corresponding foreign asset and liability categories. U.S. earnings from abroad are broken down by U.S. asset holder, while foreign earnings in the U.S. are broken down by U.S. liability holder. The more detailed treatment of receipts and payments ensures that the U.S. investment balance responds correctly to changes in the U.S. foreign debt and interest rates.

Third, the reactions of overseas prices, interest rates and GDP to U.S. development have been made robust and automatic. In the case of a dollar depreciation, for example, U.S. activity may expand at the expense of foreign activity and U.S. inflation may rise while the rate in other countries slows.

Financial: The use of a detailed financial sector (V) and of interest rate and wealth effects in the spending equations recognizes the importance of credit conditions on the business cycle and on the long-run growth prospects for the economy.

Interest rates, the key output of this sector, are modeled as a term structure, pivoting off the federal funds rate, the discount rate, and the Treasury bill rate. As noted earlier, these short-term rates depend upon the balance between the demand and supply of reserves to the banking system. The supply of reserves is the principal exogenous monetary policy lever within the model, reflecting the Federal Reserve's open market purchases or sales of Treasury securities. Banks and other thrift institutions demand reserves to meet the reserve requirements on their deposits and the associated (exogenous) fractional reserve requirements. The private sector in turn demands deposits of various types, depending on current yields, income, and expected inflation.

Longer-term interest rates are driven by shorter-term rates as well as factors affecting the slope of the yield curve. In the DRI Model, such factors include inflation expectations, government short- and long-term borrowing requirements, corporate financing needs, and the recent volatility of interest rates. The expected real rate of return varies over time and across the spectrum of maturities. An

important goal of the financial sector is to capture both the persistent elements of the term structure and to interpret changes in this structure. Twenty-six interest rates are covered in order to meet client needs regarding investment and financing allocation strategies.

Inflation: Inflation (VI) is modeled as a carefully-controlled, interactive process involving wages, prices, and market conditions. Equations embodying a near accelerationist point of view produce substantial secondary inflation effects from any initial impetus such as a change in wage demands or a rise in foreign oil prices. Unless the Federal Reserve expands the supply of credit, real liquidity is reduced by any such shock; given the real-financial interactions described above, this can significantly reduce growth. The process also works in reverse: a spending shock can significantly change wage-price prospects and then have important secondary impacts on financial conditions. Inspection of the simulation properties of the DRI Model, including full interaction among real demands, inflation and financial conditions, confirms that the model has moved toward central positions in the controversy between fiscalists and monetarists, and in the debates among neoclassicists, institutionalists, and "rational expectationists."

The principal domestic cost influences are labor compensation, nonfarm productivity (output per hour), and foreign input costs; the latter are driven by the exchange rate, the price of oil, and foreign wholesale price inflation. This set of cost influences drives each of the eighteen industry-specific producer price indexes, in combination with a demand pressure indicator and appropriately weighted composites of the other seventeen producer price indexes. In other words, the inflation rate of each industry price index is the reliably-weighted sum of the inflation rates of labor, energy, imported goods, and domestic intermediate goods, plus a variable markup reflecting the intensity of capacity utilization or the presence of bottlenecks. If the economy is in balance—with an unemployment rate near 5%, manufacturing capacity utilization steady near 80-85%, and foreign influences neutral—then prices will rise in line with costs and neither will show signs of acceleration or deceleration.

Supply: As noted above, the "supply-siders" have not been neglected in the DRI

Model; indeed, substantial emphasis on this side of the economy (VII) was incorporated as early as 1976. Full employment or potential national output is estimated within a production function framework, with explicit labor, business capital, energy, and research and development inputs. Total factor productivity of labor, capital, and energy is driven by research spending and trends to reflect technological progress. Taxation (and other government policies) influences labor supply and all investment decisions, thereby linking tax changes to changes in potential GNP. An expansion of potential first reduces prices and then credit costs, and thus spurs demand. We do not, however, agree with extremist supply-siders that tax cuts will pay for themselves: while they can make a significant difference in per capita living standards, tax reductions do increase the deficit and thus imply higher interest rates unless federal spending is simultaneously lowered.

Expectations: The contributions to the Model and its simulation properties of the rational expectations school are as rich as the data will support. The principal nuance relating to expectations (Sector VIII) in the DRI Model is an endogenous volatility factor influencing interest rates. Volatility, as measured by the difference between the monthly minimum and maximum values of the Treasury bill rate, increases significantly with Federal Reserve "changes of regime," shifts in wholesale price inflation and oil price shocks. Volatility adds moderately to the level of short-term rates and, by increasing the risk of investment, has an even greater impact on long-term rates. The presence of this variable allows users to achieve (and to enhance at will) the types of non-Keynesian influences stressed by the rational expectations theorists. The same may be said of the other expectational variables in the model: consumer sentiment (in household durables and semidurables), inflation expectations (in interest rates and capital spending), and growth expectations (in business investment).

Quantitative Properties and Policy Lessons

To demonstrate the interrelationships of the sectors and their responses to traditional policy initiatives, two basic shocks were introduced into simulations of the 1990-95 trend outlook: the first is a \$20 billion deficit reduction

package that increases taxes and cuts real expenditures (with the change in each tax and expenditure component proportional to its 1988 level); the second is a sustained reduction in nonborrowed reserves attributable to Federal Reserve sales of Treasury securities in the open market (Chart 2). The cut in reserves has been scaled to have the same full model impact on real GNP as the fiscal policy shock for quarters five to eight of the simulations: this interval was selected because the peak GNP impacts occur four quarters after the introduction of the fiscal shock and seven quarters after the credit restraint.

The six graphs presented as Chart 2 summarize the direct and indirect changes in fiscal and monetary policy indicators present in the two shock simulations. Note that the indirect effects are substantial, and that these have been reliably, automatically calculated by the Model.

For example, pure monetary restraint does raise federal spending (interest costs) and substantially cuts federal tax receipts (lower nominal GNP and particularly weak profits). These impacts on the deficit are much greater than the savings from generally lower inflation: as a result, within two years, a 0.5% reduction in money supply raises the federal government's annual deficit by \$10 billion.

Fiscal restraint, on the other hand, produces a significant reduction in interest rates even though the Federal Reserve is presumed not to have increased the supply of reserves to the banking system through open market purchases of Treasury securities. Moreover, the public's demand for money (often mistakenly referred to as "the money supply") is reduced without any Fed action because weaker income and spending discourages usage of currency and checks to a greater extent than the lower interest rates encourage such usage.

A switch to either restrictive monetary or fiscal policy produces a sharp cycle in the economy. There are notable differences in the responses, however (Charts 3A, 3B; Tables 2, 3). First, as just noted, the greatest impact on real GNP from the composite fiscal shock occurs within one year while the greatest impact from the monetary shock does not occur for two years. The quick fiscal response is logical given the immediacy of the cuts in government purchases and the evidence of relatively

prompt private sector responses to lower after-tax income. In contrast, changes in monetary policy affect spending with several delays: lower reserves induce higher long-term credit costs with a lag; higher interest rates in turn inhibit housing and consumer durables with a one- to four-quarter lag, and then business fixed investment with a longer lag. The feedbacks to these reactions cause the full GNP impact to build for almost two full years before the benefits of lower inflation begin to bring the economy back toward equilibrium.

Second, the relative strength of specific GNP components is quite sensitive to the type of policy restriction. Fiscal restraint has sharp and immediate negative impacts on consumption and imports; investment initially drops due to weaker output but then recovers strongly in response to lower interest rates. Housing is first trimmed modestly due to lower income but then leads the way to a general recovery in response to lower interest rates. Inflation is reduced slightly as the gains from weaker labor and product markets are offset by the costs of a lower exchange rate. The exchange rate declines as U.S. interest rates fall more than foreign rates.

Monetary restraint significantly curbs all sectors within two years, with housing and business capital spending cut back promptly and significantly. Inflation drops in response to weaker demand, and a stronger foreign exchange value of the dollar. By the second year (1991), nominal GNP is 0.4% lower with one-quarter of this reduction due to lower prices (down 0.1%) and three-quarters due to lower output (down 0.3%). By year three (1992), the lower spending level implies nominal money and credit demand reductions which are roughly proportional to the initial credit supply restraint; interest rates thus retreat back to baseline levels and the real economy begins to bounce back. This convergence of output is completed by year five (1994), and a small positive cyclical carry-over can be seen in year six (real GNP 0.1% above the baseline). These patterns resemble monetarist conclusions that real output losses are largely transitory and that the price level will drop by about the same percentage as the decline in the nominal supply; but these findings are tempered by the growth model lesson that capital

Chart 2
Simulation Results: Indicators of Policy Changes

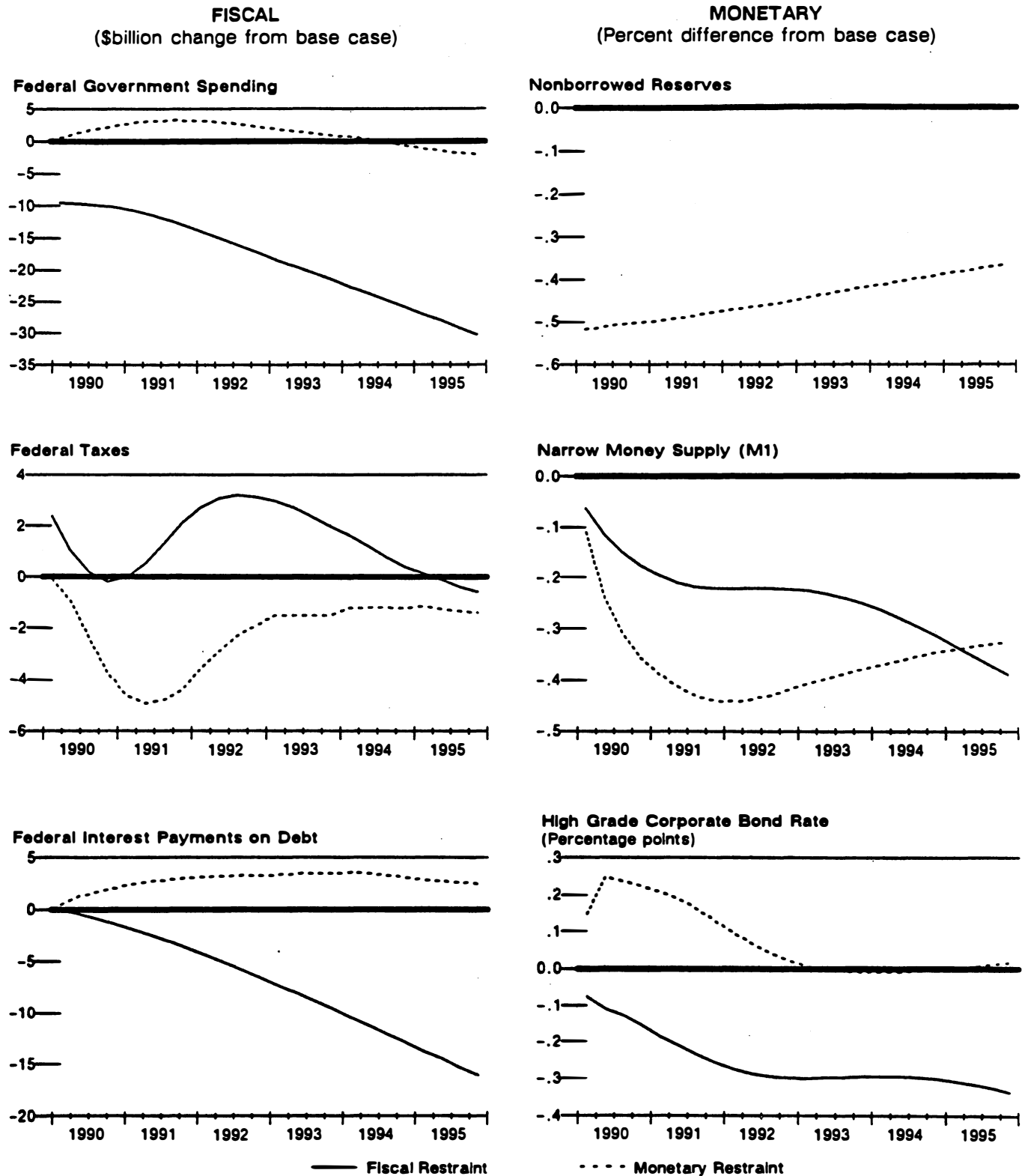


Chart 3A

Simulation Results:

Macroeconomic Responses to Fiscal and Monetary Policy Changes

(Percent difference from base case)

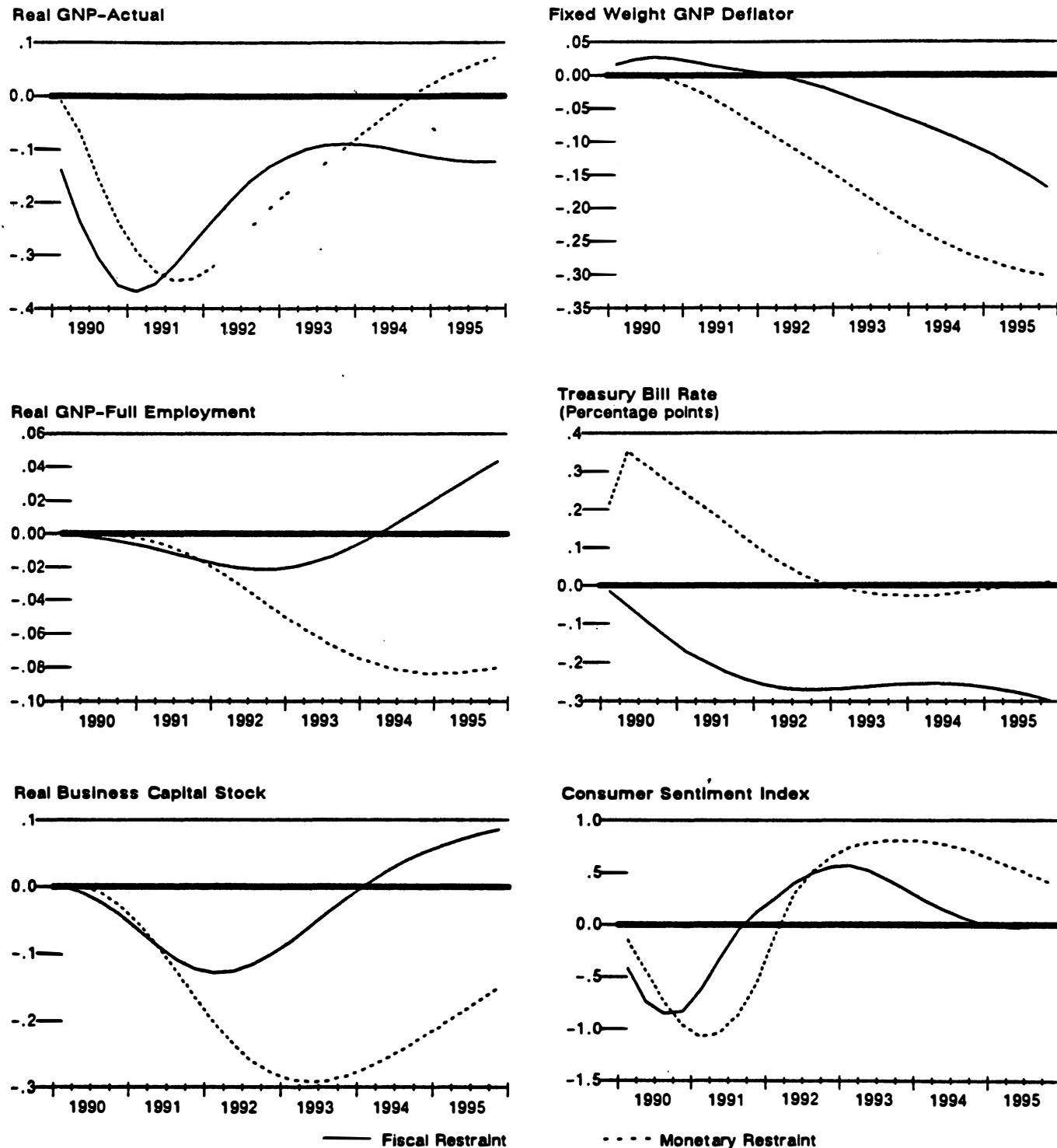


Chart 3B

Simulation Results:

Macroeconomic Responses to Fiscal and Monetary Policy Changes

(Percent difference from base case)

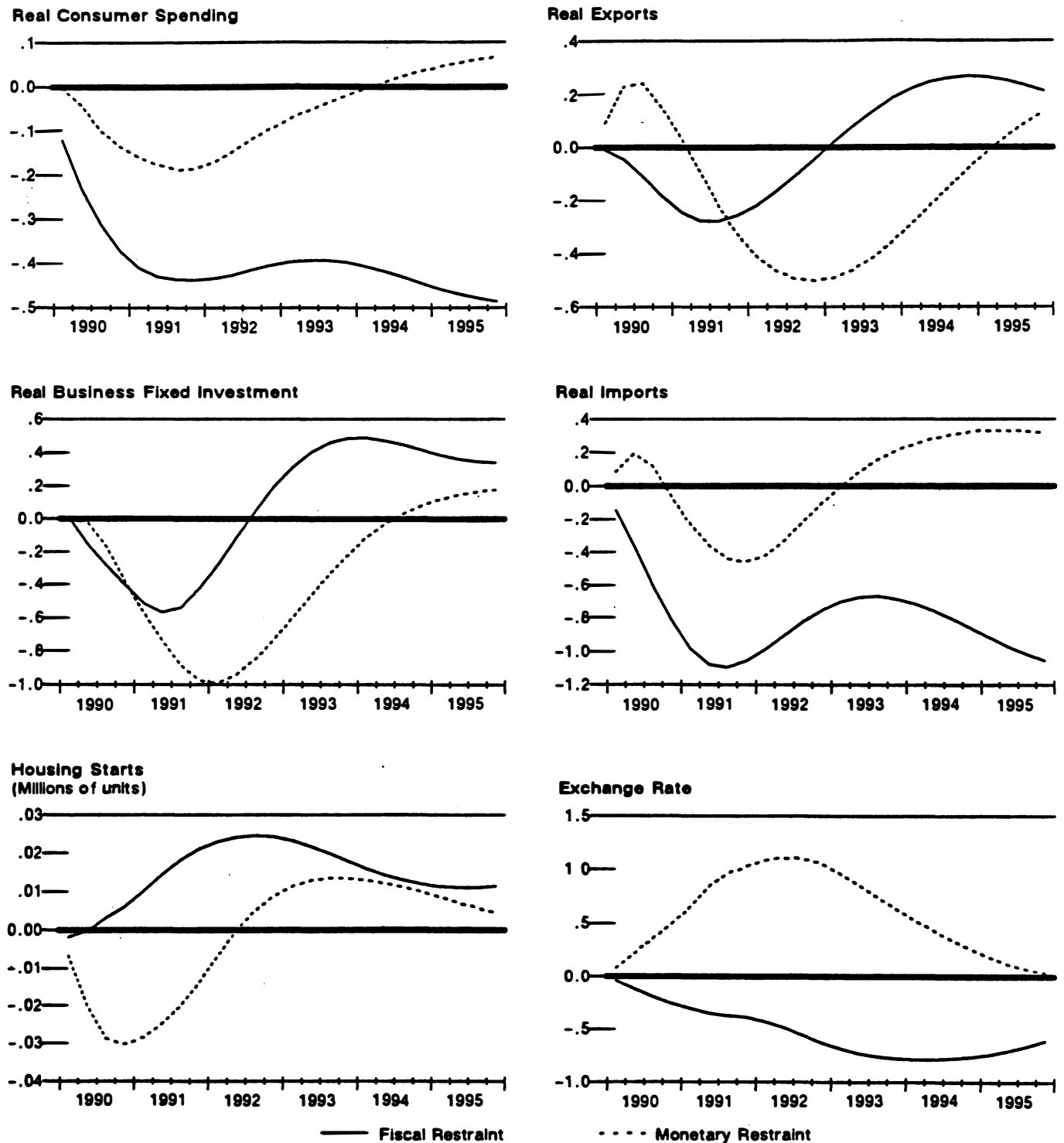


Table 2
Impacts of a Fiscal Restraint Package
 (Percent difference from baseline unless otherwise indicated)

	1990	1991	1992	1993	1994	1995	1990-95
Supply							
Business Capital Stock.....	0.0	-0.1	-0.1	0.0	0.1	0.1	0.0
Number of Homes.....	0.0	0.0	0.0	0.0	0.1	0.1	0.0
Full-employment Real GNP.....	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Actual Non-farm Output per Hour	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1	-0.1
Demand (Inflation-adjusted)							
Consumer Spending.....	-0.3	-0.4	-0.4	-0.4	-0.4	-0.5	-0.4
Fixed Investment.....	-0.2	-0.3	0.2	0.5	0.5	0.4	0.2
Residential.....	-0.1	0.3	0.9	0.9	0.6	0.5	0.5
Nonresidential.....	-0.2	-0.5	0.0	0.4	0.5	0.4	0.1
Equipment.....	-0.3	-0.6	0.0	0.4	0.4	0.2	0.0
Structures.....	0.0	-0.3	-0.1	0.4	0.8	1.1	0.3
Exports.....	-0.1	-0.3	-0.1	0.1	0.2	0.2	0.0
Imports.....	-0.5	-1.1	-0.9	-0.7	-0.8	-1.0	-0.8
Real GNP.....	-0.3	-0.3	-0.2	-0.1	-0.1	-0.1	-0.2
Nominal GNP.....	-0.2	-0.3	-0.2	-0.2	-0.2	-0.3	-0.2
Wages and Prices							
Hourly Wages.....	0.0	-0.1	-0.2	-0.2	-0.3	-0.3	-0.2
Consumer Prices.....	0.0	0.0	0.0	0.0	0.0	-0.1	0.0
Producer Industrial Prices.....	0.0	-0.1	0.0	0.0	-0.1	-0.1	-0.1
Financial Conditions							
Standard & Poor 500 Index.....	0.0	0.9	1.5	1.4	1.2	1.4	1.1
Prime Rate*.....	-0.06	-0.20	-0.27	-0.26	-0.24	-0.27	-0.22
Mortgage Rate*.....	-0.17	-0.32	-0.40	-0.41	-0.41	-0.44	-0.36
Corporate Bond Rate*.....	-0.12	-0.22	-0.29	-0.30	-0.30	-0.32	-0.26
Post-tax Profits.....	-4.0	-2.3	0.1	-0.1	-1.3	-1.6	-1.5
Corporate Cash Flow.....	-1.2	-0.7	-0.1	-0.1	-0.2	-0.1	-0.4
Money Demand (M2).....	-0.2	-0.2	-0.2	-0.3	-0.3	-0.4	-0.3
Exchange Rate.....	-0.2	-0.4	-0.5	-0.7	-0.8	-0.7	-0.5
Other Indicators							
Unemployment Rate*.....	0.08	0.14	0.09	0.04	0.04	0.06	0.08
Employment.....	-0.1	-0.2	-0.1	-0.1	-0.1	-0.1	-0.1
Industrial Production.....	-0.4	-0.5	-0.2	0.0	-0.1	-0.1	-0.2
Capacity Utilization Rate (Mfg)	-0.4	-0.5	-0.1	0.0	-0.1	-0.2	-0.2

Difference, billions of dollars

Federal Budget							
Receipts.....	5	4	6	6	5	3	5
Personal Taxes.....	3	2	2	2	2	1	2
Corporate Taxes.....	-2	-1	1	1	0	-1	-1
Expenditures.....	-10	-12	-16	-20	-24	-29	-18
Interest.....	-1	-3	-6	-8	-12	-15	-7
Budget Balance.....	14	16	22	26	29	32	23

*Difference in percentage points.

Table 3
Impacts of a Monetary Restraint Package
(Percent difference from baseline unless otherwise indicated)

	1990	1991	1992	1993	1994	1995	1990-95
Supply							
Business Capital Stock.....	0.0	-0.2	-0.3	-0.3	-0.2	-0.2	-0.2
Number of Homes.....	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Full-employment Real GNP.....	0.0	0.0	0.0	-0.1	-0.1	-0.1	0.0
Actual Non-farm Output per Hour	-0.1	-0.1	-0.1	0.0	0.0	0.0	-0.1
Demand (Inflation-adjusted)							
Consumer Spending.....	-0.1	-0.2	-0.1	0.0	0.0	0.1	-0.1
Fixed Investment.....	-0.3	-1.0	-0.8	-0.2	0.1	0.2	-0.3
Residential.....	-0.8	-1.4	-0.5	0.3	0.4	0.4	-0.3
Nonresidential.....	-0.1	-0.8	-0.9	-0.4	0.0	0.2	-0.3
Equipment.....	-0.2	-0.9	-0.8	-0.3	0.1	0.2	-0.3
Structures.....	-0.1	-0.6	-1.1	-0.9	-0.5	-0.2	-0.6
Exports.....	0.2	-0.2	-0.5	-0.4	-0.2	0.1	-0.2
Imports.....	0.1	-0.4	-0.3	0.1	0.3	0.3	0.0
Real GNP.....	-0.1	-0.3	-0.3	-0.1	0.0	0.1	-0.1
Nominal GNP.....	-0.1	-0.3	-0.3	-0.3	-0.3	-0.3	-0.3
Wages and Prices							
Hourly Wages.....	0.0	-0.1	-0.2	-0.3	-0.3	-0.4	-0.2
Consumer Prices.....	0.0	0.0	-0.1	-0.2	-0.3	-0.3	-0.2
Producer Industrial Prices.....	0.0	-0.2	-0.3	-0.3	-0.3	-0.2	-0.2
Financial Conditions							
Standard & Poor 500 Index.....	-1.6	-2.0	-0.7	-0.1	-0.1	0.0	-0.7
Prime Rate*.....	0.34	0.23	0.04	-0.04	-0.04	-0.01	0.09
Mortgage Rate*.....	0.26	0.22	0.08	0.00	-0.01	0.01	0.09
Corporate Bond Rate*.....	0.21	0.17	0.06	0.00	-0.01	0.01	0.07
Post-tax Profits.....	-2.4	-3.8	-0.7	1.0	1.2	0.5	-0.7
Corporate Cash Flow.....	-0.6	-1.0	-0.3	-0.1	-0.2	-0.4	-0.4
Money Demand (M2).....	-0.3	-0.4	-0.4	-0.4	-0.3	-0.3	-0.3
Exchange Rate.....	0.3	0.9	1.1	0.8	0.4	0.1	0.6
Other Indicators							
Unemployment Rate*.....	0.03	0.12	0.11	0.05	-0.01	-0.05	0.04
Employment.....	0.0	-0.2	-0.2	-0.1	0.0	0.1	-0.1
Industrial Production.....	-0.2	-0.6	-0.4	-0.2	0.0	0.2	-0.2
Capacity Utilization Rate (Mfg)	-0.2	-0.6	-0.3	0.1	0.3	0.4	0.0
Difference, billions of dollars							
Federal Budget							
Receipts.....	-2	-6	-5	-4	-3	-3	-4
Personal Taxes.....	0	-1	-2	-2	-2	-2	-1
Corporate Taxes.....	-2	-4	-1	1	1	0	-1
Expenditures.....	2	3	3	1	0	-2	1
Interest.....	1	3	3	3	3	3	3
Budget Balance.....	-4	-10	-8	-5	-3	-1	-5

*Difference in percentage points.

formation losses will also occur, and these imply persistent real production restraints and hence real income losses.

An important goal of the DRI Model is the provision of policy insights and guidance. Restrictive monetary policy is clearly the strategy of last resort for slowing the economy, even if inflation is the highest priority problem. The long-term consequences of restricted credit growth are clearly adverse: business investment and housing are significantly weaker, entailing a permanent reduction in the nation's capital stock and labor productivity. Also important is the real appreciation of the dollar, leading to expanded imports and lost exports. The best cure for inflation is a carefully targeted reduction in federal spending.

These results starkly point out that the worst possible mix is a pairing of stimulative fiscal and restrictive monetary policy. Both policies serve to increase federal deficits, drive up the exchange rate and international trade deficits, and reduce long-term business capital formation and housing construction. If these lessons can be taught to Washington, business performance can be substantially improved.

Broad Model Management Techniques

Although the Model is large and accurately reflects the complexity of the U.S. economy, user management of the model need not be time-consuming or complex. Once the user has read this overview and the basic software documentation, he or she should be ready to perform serious, full-blown analyses of business and policy situations. Greater expertise can be developed through utilizing the "Simulation Tips" or the detailed sectoral presentations in the Model Documentation Manual, reading the appropriate sections of the comprehensive Software Manual, or by attending DRI seminars; however, one need not master the nuances of all equations before feeling very comfortable using the model to produce useful forecasts and alternative scenarios for your organization.

Each user is always provided with the DRI baseline forecast, and most users regularly or intermittently subscribe to standard DRI alternatives. These all come with "modelnotes" de-

scribing the choices DRI senior economists have made in managing Model forecasts of private sector behavior or in setting policy variables. The motivations for additional, user-specific scenarios typically fall into one or two comparable categories: presumed differences in the cyclical condition of private sector variables or in monetary and fiscal policies. Only a small set of variables normally need to be managed to orchestrate a new cyclical scenario, not the full set of 321 behavioral variables. Likewise, only about a half-dozen fiscal levers need to be understood to implement a presumed shift of federal policy assumptions.

1. The consumer sentiment index (with a mnemonic of "JATTC") is the most direct and appropriate variable to be manipulated to reset broad consumer behavior; it will materially influence the durable (auto and furniture), nondurable (clothing and gasoline), and service (transportation and finance) categories that really do change with shifts in consumer willingness to spend. The other categories will respond to changes in income flowing from shifts made elsewhere in the Model.
2. Single- and multi-family housing starts (HUSTS1 and HUSTS2&) should be modified to reflect greater or weaker forecasts of residential construction for any given level of interest rates and household income.
3. The two largest categories of capital spending, buildings (ICNRB&O82) and basic machinery (IPDENROTHR82), can be adjusted to temper the basic DRI forecasts. The inventory cycle can be shifted by manipulating any component, but retail stocks (INVTR82CH) are usually the first to display a cyclical excess and to be reduced.
4. Each of the detailed import and export categories can be adjusted by changing just the two aggregate trade adjustment factors (EX82ADD and M82ADD) because the Model will automatically spread these adjustments appropriately across the individual merchandise categories.
5. Higher inflation stemming from a presumption of greater cost pressures should be implemented by changing wages (ECIWSPNS), oil prices (PCOF), foreign local-currency wholesale prices (WPIW),

or the exchange rate (EXCH); greater "demand-pull" inflation will automatically arise if the final spending categories are increased, or if the user adjusts the purchasing manager index of delivery bottlenecks (RDELYSLOW).

6. A change in the profit or personal income outlook usually implies a change in the GNP outlook, achieved by one of the final demand or inflation manipulations described immediately above. Any other change is, by definition, almost always a disagreement about the distribution of income. Remembering that profits are the residual income component, a change in the profit forecast is usually best achieved by modifying the wage or price forecast first, and then adjusting the number of hours worked. The hours forecast will be appropriately changed if nonfarm output per hour (JQ%MHNF) is adjusted; this approach ensures that consistent answers are obtained for national output, productivity, and hours worked.
7. Tighter credit conditions will flow throughout the model in response to an increase in the federal funds rate (RMFEDFUNDNS); the yield curve can be made steeper by increasing interest rate volatility (VOLA).
8. The largest discretionary federal expenditure categories are military hardware (GFML082), transfer payments

(VGF@PERHI82), and grants-in-aid to states or local government (VAIDGF@SL82). Federal taxes should usually be manipulated through the tax rates on personal income (RTPGF) and corporate profits (RTCGFS). Excise tax changes are neatly handled through the taxes on gasoline (GASTAXF) or all other items (DMYTXGF).

In almost all cases suggested above, the user has the choice of either (a) holding the targeted variable on a path precisely differing from the original simulation by the magnitudes, proportions, or growth rates selected by the user, or (b) allowing Model feedbacks to make further adjustments. Changing a variable directly by name (e.g., JATTC or RMFEDFUNDNS) will make the rigid shift. Changing the constant term in the equation determining the variable will allow for subsequent feedback effects; such changes are accomplished by adjusting "add-factors" which are represented in the Model as the variable name preceded by an "&" (e.g. &JATTC or &RMFEDFUNDNS). Of course, variables which are themselves rigid policy choices or external assumptions do not have add-factors and must be managed by direct changes; in the eight sections above, these variables are federal expenditures, the statutory corporate tax rate, the two excise tax levers, and the aggregate trade adjustment factors.

THE DRI ENERGY MODEL

The DRI Energy/Economic Modeling System was designed to analyze the impacts of major energy issues on the energy sector and the feedback effects from energy markets on the U.S. economy. The system is composed of:

- DRI's Macroeconomic Model of the U.S. Economy
- DRI's Energy Model

In the Energy/Economic Modeling System, the simultaneity between energy and the economy is dealt with through iterative solutions of the DRI Macroeconomic and Energy Models. The macro Model defines the economic environment in which the energy markets are operating. Projections of real GNP growth, inflation, industrial production, employment, income, housing, vehicle sales, etc., are provided to the Energy Model by the Macro Model. Also feeding into the Energy Model is a complete array of present and expected future energy regulations which impact the pricing and/or availability of domestic energy supplies and assumptions regarding the technical or efficiency characteristics of the energy-using capital stocks. With these inputs, the Energy Model first determines world oil and natural gas prices. The system then solves for the prices, demands, and supplies of the major energy sources in the U.S. The major forecasts for prices and demands are given by consuming sector and by region of the country.

Energy Model

The Energy Model develops the prices and the demands for the major fuels and for electricity in the residential, commercial, industrial, and transportation sectors on a regional basis for the total U.S. Exhibit A displays the eleven regions of the Energy Model. The model also translates the electricity demands into the generation requirements and determines the fuel consumption and costs (average electricity price) associated with the generation process in the electric utility sector of the Model. Exhibit B summarizes the interactions within the Energy Model. Pricing in the Energy Model and demands by sector are discussed below.

Energy Prices

Oil: The Energy 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.

Crude oil prices are projected for imported and domestic oil. Imported oil prices are based upon the analysis using the World Oil Model. Domestic wellhead prices by supply source reflect the world oil price and the quality of the source. Average domestic and acquisition crude oil prices are calculated as supply-weighted averages of these prices.

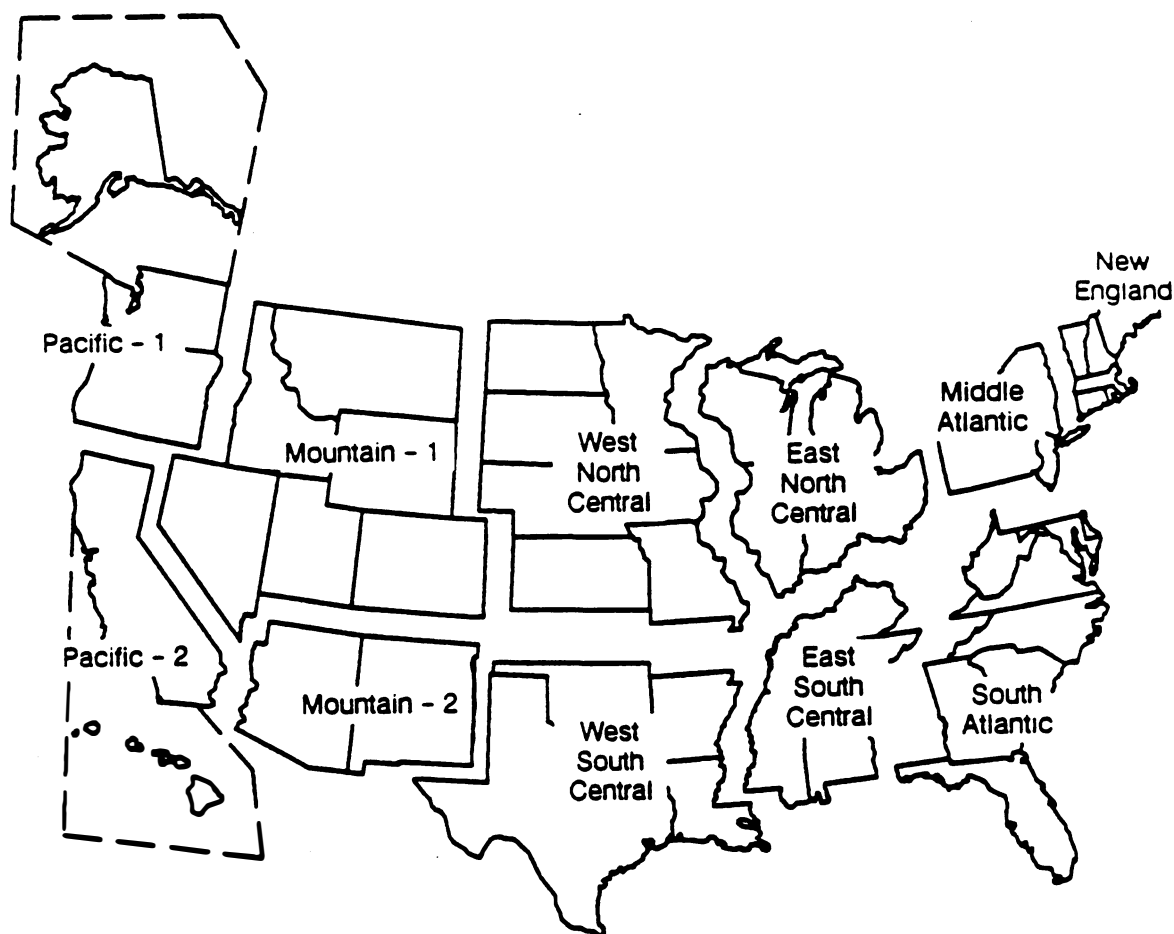
Petroleum product prices are based upon the average refiner acquisition price of crude oil and assumptions regarding refiner markups which insure that product revenues cover refiners costs. Gasoline prices incorporate additional assumptions with respect to federal, state and local taxes, and retailer markups.

Natural Gas: Natural gas prices within the model reflect (1) policy assumptions regarding the pricing of spot versus contract gas, of Canadian and Mexican imports, and of LNG and SNG supplies, (2) the regional transportation and distribution markups to each consuming sector, and (3) a market demand/supply balance for the long-term.

First, the natural gas prices by spot and contract markets are developed. Second, the regional average pipeline acquisition cost is computed as a volume weighted average of all gas sources, domestic and supplemental. Third, retail industrial, residential, commercial, and electric utility prices are developed by adding regional transportation and distribution markups to pipeline acquisition costs.

Electricity: Electricity prices to residential, commercial, and industrial customers are modeled regionally based upon the average cost of generating the electricity. Utilities' costs are the equivalent of their revenue requirements. Hence, utilities revenue requirements relative to kilowatt hour demands define the average electricity prices in each of the regions.

CHART 1
ENERGY DEMAND REGIONS



Energy Demands

The consumption of electricity, natural gas, and oil in the residential, commercial, and industrial sectors is determined through a two-step decision process. The first step is the *stock* decision. This entails a) the decision to purchase the capital which provides an energy service: given demographic (production) trends and existing stocks, *how many* furnaces (boilers) are required for new homes (plants) or to replace exhausted units, and b) the decision as to the characteristics of the capital stock being chosen: *what types* of equipment are to be installed, (electric, natural gas, oil, coal) and what are the structure thermal integrities or new equipment efficiencies which characterizes the stock. Decisions at this stage determine the size and the fuel efficiency characteristics of the energy service capital stock, and limit the flexibility in the sectors' fuel mix and conservation potentials. The second step in

the process is the *utilization* decision for the selected energy-service capital stocks. Utilization varies as a function of economic factors and climate.

The final BTUs of energy consumed by energy type are therefore based upon the capital stocks, their efficiencies, and their utilization of these stocks.

Residential: The economic forecasts from the DRI Macroeconomic Model set the stage for the energy service demands in the model. Housing stocks, real disposable income, and population define a demand for such energy services as heating, cooling, and refrigeration.

The model determines the levels and the energy use characteristics for 10 residential stocks providing energy services. Stocks are defined based upon existing stock characteristics and new investment decisions. New

[illegible]

investment decisions for space conditioning, for example, are based upon detailed life cycle cost analyses. Less involved analyses support the investment decisions for the other energy services.

Life cycle costs are defined as the sum of equipment and installation costs plus the present discounted value of the energy costs associated with the service equipment. Costs are evaluated for competing space conditioning systems in both the new housing and the replacement market. In analyzing the replacement market, the model keeps track of the space conditioning system vintages. Life cycle costs in the replacement market include conversion costs when evaluating the decision to switch to an alternative system.

The model acknowledges four caveats which preclude a determination of new and replacement systems based solely upon average life cycle cost calculations. These include:

1. Housing access to natural gas main extensions.
2. The inherent bias toward the existing system when replacing a retired system.
3. Market imperfections due to first-cost bias in the investment decision.
4. Variations in energy costs, household size, thermal integrity, preference, etc., within any given region.

Caveats 1 and 2 are handled through adjustments to system installations costs. Caveat 3 is dealt with through the discounting techniques in the life cycle cost calculations, and caveat 4 is acknowledged by associating probability distributions about the mean life cycle cost estimates.

After the stock decision is made, the utilization of the stock is determined. Utilization varies with the efficiency of the capital stock, economic factors and climate. Economic factors include real disposable income per capital and the real energy service costs. The impact of climate on the utilization of space conditioning systems is accounted for by deviations in heating and cooling degree days from their norms.

Commercial: The structure of the Commercial Submodel parallels that of the Residen-

tial Submodel. Energy consumption by the sector is determined by analyzing the energy service requirements associated with the commercial square footage forecasts. The model considers six energy services within the commercial sector. Energy service-per-square-foot coefficients translate square footage forecasts into energy service (stock) requirements. New energy service requirements (investments) are determined by the growth in square footage, and hence service stock. New investments are allocated across each equipment type in each energy service, and are rolled in with the existing stock to define the fuel and efficiency characteristics of the current stock of energy service equipment.

Stock utilization is defined as the commercial sector's electricity, gas and oil consumption relative to the levels of equipment or service stocks fueled by the respective energy types. Utilization is modeled as a function of equipment operating costs, heating and cooling degree days, and building utilization rates.

Industrial: The model determines industrial energy consumption through a detailed analysis of the energy service requirements associated with the industrial production forecasts from the DRI Macroeconomic Model. Energy service refers to the end use provided by the energy in the industrial process. A maximum of nine services are associated with production in each of eleven industries or industry groupings. Four of the energy services -- process steam, machine drive, direct heat, and indirect heat -- can be provided by more than one equipment type (i.e. fuel type). The model determines investment and stocks by fuel type based upon the life cycle costs associated with the alternative fuel types, as in the Residential and Commercial Submodels.

New investment requirements for each energy service are segmented into four size-utilization classifications, reflecting the operating characteristics of the industries supporting the investment. Technical constraints on coal usage due to environmental, space limitation, and/or product contamination considerations further segment the markets into coal and non-coal capable submarkets.

The model determines actual energy consumption as the utilization of the energy

service capital stock. Utilization is defined for the three major energy types -- coal, oil/natural gas, and electricity -- as energy consumption per unit of energy service stock, and is modeled as a function of the real price of energy services, industrial capacity utilization, and technological change. The combined demand for oil and natural gas is split between the two fuels based upon the composition of petroleum supplies, the service characteristics of the demand, and the relative prices of the two fuels.

Transportation: The Transportation Submodel projects demands by automobiles and by trucks for fuel types; gasoline, diesel and alternative fuels. The model incorporates a detailed analysis of the vehicle stock, the economic and technical characteristics affecting the utilization of the vehicle stock, and the efficiency ratings of the stock. Stock efficiency ratings translate projected miles traveled into fuel demand. The six major outputs of the Transportation Submodel are:

1. Vehicle (automobile or truck) sales by fuel type
2. Vehicle stocks by fuel type
3. Vehicle stock efficiencies
4. New vehicle efficiencies
5. Vehicle miles traveled
6. Motor fuel demands by fuel type

Automobile and truck sales from the Macroeconomic Model are disaggregated by fuel type. Vehicle stocks and 'effective' vehicle stocks by fuel type are computed as the summation of current and lagged vehicle sales, adjusted by the survival rates associated with each vintage for the former and by the survival and typical usage rates for the latter. Stock fuel efficiencies are computed based upon the new efficiency associated with each vintage and the usage rate associated with each vintage. New vehicle efficiencies are positively related to the real price of gasoline and negatively related to exogenous projections of vehicle weight.

Miles traveled by automobiles (trucks) are functions of real income per capita (real GNP per truck), and real fuel costs per mile. Real fuel costs per mile reflect the gasoline price, price inflation, and the average efficiency of the

automobile or the truck stock. Total fuel demand by vehicle type is derived by dividing the miles driven for each vehicle type by the vehicle's stock efficiency estimate. The total is then apportioned into gasoline and diesel fuel demand based upon the fuel composition of the "effective" vehicle stocks.

Electric Utility: Total electricity generation requirements by region are determined by adjusting the electricity demands within each region for transmission losses and interregional power transfers. The model determines the means by which utilities satisfy their generation requirements, i.e., their generation mix, based upon the existing capacity mix and relative fuel prices. Electricity is generated from the following sources:

1. Solar and Geothermal
2. Hydropower
3. Nuclear
4. Coal
5. Natural Gas
6. Oil

Generation of electricity from solar, geothermal, hydropower and nuclear energy sources is based upon their respective regional capacity levels and specified utilization rates. As these power sources have lower variable costs than those of plants using fossil fuels, it is assumed that these plants will be utilized up to their maximum potentials.

The remaining generation requirement must then be satisfied by fossil fuels. It is assumed the coal facilities will be utilized, whenever possible, over oil and natural gas facilities because of their lower variable operating costs. Hence, generation from coal is determined based upon coal capacity levels and maximum utilization rates.

Peaking demand and any base or immediate load generation requirements not met by the above low-variable operating sources, must be provided by more costly oil and natural gas generation. This generation requirement is distributed between residual fuel oil and natural gas based upon the relative prices of the fuels.

Generating capacity additions are exogenous inputs to the model in the initial years of

the forecast. These future plants are known to exist due to the long planning horizons for new generating plant construction. In the later years, plant capacity additions are determined by the model. The model solves for the "optimal" capacity requirements in later years, in each utility planning region, based upon the region's "expected" generation requirements for

the year. "Optimal" capacity is defined as that which would assure a desired reserve margin for the region while "expected" generation is calculated based upon the growth in generation in previous years. If the "optimal" capacity calculation implies an increase in generating capacity greater than a specified magnitude, capacity is added to the region.

REGIONAL INFORMATION SERVICE METHODOLOGY

Overview

DRI/McGraw-Hill uses a fully integrated approach to forecasting economic activity at the national, regional and state levels. DRI's U.S. Quarterly Model determines the national economy's growth path; regions and states compete with each other for available growth. The Regional Information Service uses a system of quarterly models to forecast over 50 concepts for each state and region. The principal indicator of sectoral economic activity is employment, which is forecasted for 20 manufacturing and 10 nonmanufacturing industries. Wage rates and major components of personal income are modeled, as well as homebuilding activity, population, labor force and unemployment rates.

Simulation of DRI's regional models involves a two-stage process. The core model is first solved for levels of activity in nine regions: New England, Middle Atlantic, South Atlantic, East North Central, East South Central, West North Central, West South Central, Pacific Northwest and Pacific Southwest. The sum of regional economic activity is constrained to sum to the national total. In the second stage, nine regional models are solved to obtain forecasts for the states within each region, constraining state forecasts to add up to regional totals.

The regional modeling system is based on the premise of regional and state competition, rather than a simple allocation of national economic activity based on fixed relationships. Competition centers around factors influencing a firm's locational decisions. The decision to move between regions is driven by:

- Proximity to markets and suppliers,
- Costs considerations such as wages, energy prices, housing prices and taxes,
- Quality of labor-education and degree of unionization,
- Climate, and
- Quality of life.

Within a region, the forces affecting business location are more limited. States are essentially competing for a share of the business

drawn to that particular region. Business taxation and relative costs are key attributes in determining a state's ability to compete with its neighbors.

DRI's regional models are export base models. The principle underlying the export base structure is that regional growth is generated primarily when locally produced goods and services are sold to customers outside the region. The inflows of income produced by such inter-regional transactions will then generate a multiplier effect on the local economy. In contrast, intra-regional transactions only redistribute income. Those industries which sell their products to markets outside the region constitute the export base. In DRI's regional models, the export base is composed of manufacturing, mining, federal governments, and some portion of other service-related sectors.

Manufacturing Employment

The manufacturing sector is examined in detail, because of its importance in each area's economic base. All of the 20 two-digit SIC industries are analyzed separately, in a pooled time-series cross-sectional framework. This technique makes possible the inclusion of a variety of cross-sectional concepts which could not be used in a conventional time-series regression. These include climate and attractiveness, which do not change over time, and other variables such as unionization, education, personal and business taxes, which change so rarely or so gradually that they are not distinguishable from a time trend in the absence of cross-sectional methods.

Three categories of explanatory variables are used. The first major type of variable explaining these movements relates to the mix of activities within each two-digit SIC sector. Where DRI's national model forecasts at the three-digit level, the historical mix in each region has been used to construct an indicator of the relative growth that the region can expect simply on the basis of differences in three-digit mix.

In addition, another variable has been designed to measure differences in the amplitude of the business cycle in each industry among regions; this allows implicitly for the effects of different three-digit mix even when there are no reliable forecasts of the separate three-digit markets.

Thirdly, the model looks at relative costs of doing business, including wage rates, tax burdens, energy prices (using electricity prices as a proxy), unionization and education of the labor force, and home prices. Most of these are examined both in terms of the impact of existing inter-regional differentials, and also in terms of the effect of different rates of change, in order to distinguish between variables whose effects persist over time, and those which matter only when they change.

Finally, it is clear that a significant factor in many business and personal decisions is the underlying quality of life; the model looks at climate (measured by heating degree days), top personal tax rates, and a general measure of attractiveness (the indicator used is the proportion of total employment dependent on tourism). Some of the concepts used in RIS may be relevant both to business costs and to the quality of life; specifically, the climate will affect the cost of space-heating for business, and home prices will have an impact on the quality of life for individuals as well as on the price that businesses have to pay both for property and for people.

Not all of these variables are significant in every industry or within every region, but in total they all have a substantial impact on the location of manufacturing jobs. The forecasts of theme come from other DRI services (e.g., electricity prices for the energy service), or are assumptions which can be changed by the user (e.g., unionization, tax rates), or are endogenous to the RIS model (e.g., wage rates, home prices, market demand).

Industrial Production

Data on industrial production by industry has not been available at the state level for a number of years, since budget cuts caused the Bureau of the Census to cease publishing the state results for the annual Survey of Manufacturers. DRI has therefore developed production indices based on national input-output data and state employment statistics. The assumption is made that output per employee is the same in all states at the 432-sector level of detail from DRI's input-output table. This is then combined with data from County Business Patterns on employment by four-digit SIC codes, to generate measures of output per employee by state for two-digit manufacturing industries; these differ from state to state because of the different

four-digit mix within each two-digit sector. These two-digit productivity series are then applied to the two-digit employment forecasts from the RIS model to provide levels of industrial output, which are then indexed to a base of 1.0 in 1973 (first quarter).

Non-Manufacturing Employment

Certain elements of non-manufacturing employment are also part of an area's economic base. Mining employment is driven by information from DRI's Coal, Steel and Drilling services, and by the model's own forecast of construction activity. Federal government employment, which is distributed largely on the basis of population, can also be viewed as part of the economic base. Most non-manufacturing sectors, however, are principally driven by the local economy. Construction is entirely oriented towards local demand, being driven by indexes of residential and nonresidential construction activity. The residential index depends on single- and multi-family housing starts in recent quarters; the nonresidential index is a function of positive changes in total nonconstruction employment (representing the demand for new work places), and of the overall level of employment (representing the normal demand for maintenance and alterations of existing structures). State and local government employment is determined by tax revenues, using average business and non-business tax rates in relation to total personal income in the state. The other non-manufacturing sectors are:

- Transportation, communications, and utilities;
- Trade;
- Finance, insurance, and real estate;
- Services.

All of these are primarily driven by local needs, but each contains components that serve wider markets. International and national banking and insurance, many business services, and a wide variety of activities related to tourism, are all examples of economic-base elements within non-manufacturing. The proportion of each of these four sectors which is export-oriented has been estimated by means of a minimum-requirements test. For each sector, the proportion of total employment was calcu-

lated for every state and region, and the lowest proportion was used as an indicator of the amount of, for example, service employment which is "needed" by a region. Any employment above that proportion is treated as export-oriented, and is tied in the model to demand in the rest of the region and the rest of the country.

Wages and Incomes

The largest component of personal income is wages and salaries; the model therefore focuses on wage rates, identifying separately hourly wages in manufacturing, and average annual wages and salaries in manufacturing and in non-manufacturing by one-digit SIC sector (the same level of disaggregation as for employment). Average hourly wage rates are forecast using a measure of national wages adjusted for each state's two-digit manufacturing mix. Regional wage rates grow at the rate determined by industry mix, with some tendency to convergence, and also with a pressure for faster growth if total employment is growing faster than in the rest of the country. Non-manufacturing wages follow manufacturing, except that in general they are somewhat more sensitive to transitory labor-market conditions.

For wages, equations were estimated at the national level for average annual wages and salaries in each sector, using forecasts of hourly wage rates from DRI's Cost Forecasting Service where appropriate, and relative sectorial growth in other cases. These national average annual wage rates were then used to generate regional and state forecasts, by imposing the same relative rates of growth. For example, if construction wages in the nation are forecast to grow 10% faster than the average for non-manufacturing in the third quarter of 1985, then this same relationship will be assumed to hold in each region. This does not imply that construction wages will be forecast to grow at the same rate everywhere, since average non-manufacturing wages are forecast for each state and region based on a complex set of factors reflecting economic activity in the area, and these can and do differ substantially from place to place. A constraining procedure is also used to ensure that the total amount of wage and salary disbursements implied by these wage rates is consistent with the national and regional forecasts.

Non-wage income is divided into two aggregates, taxable and non-taxable. The equations for these include terms relating to each major component of non-wage income:

- Other labor income;
- Transfer payments (federal and state & local);
- Residence adjustment;
- Non-farm proprietors' income;
- Property income (dividends, interest, and rent).

Each term looks at the relevant national variable, and at a regional concept which can be viewed as driving the particular type of income. Farm proprietors' income is treated separately, using DRI's forecasts of state production and cash receipts from crops and livestock.

The final critical category of income in regional analysis is the residence adjustment; this is required because official estimates of wage income are based on data collected by place of work, while income is defined as place of residence. The adjustment thus represents an addition to income if many residents commute across state lines to work, and a negative number if many of the state's jobs are held by residents of other areas. The specification of the equation for the residence adjustment therefore depends upon the sign of the concept over history; where it is negative, it is estimated as a proportion of total wages and salaries in the state (or region); where it is positive, it has been estimated as a proportion of total wages and salaries in neighboring states or regions to which it appears that area residents commute. Generally, commuting is to and from contiguous areas, which can be easily identified by finding major metropolitan areas that lie across or close to state lines (e.g., New York City); occasionally, specific events cause "commuting" over long distances, such as Texas to Alaska during the construction of the trans-Alaska oil pipeline.

Population and Labor Force

Population in the RIS model is estimated using a pooled time-series cross-sectional technique similar to the manufacturing sector. This ensures that regional population forecasts will add up to the total given by the DRI macroeconomic

model (actually, the Census Bureau's middle projection); all movements of population are therefore balanced, with no people appearing out of thin air (or disappearing).

The main determinant of differential population growth is employment. In the RIS model, people for the most part follow jobs. There is an additional element of migration in response to relative wage rates, and also a non-economic components due to climate and attractiveness; this is largely a reflection of the increasing trend towards retirement in the sun-belt. It seems that in general people move towards fast-growing regions, rather than away from depressed ones, so that there is more movement when the overall economy performs more strongly. This effect is captured in the model by the particular coefficients on relative employment and wage rate growth.

The labor force is forecast as a fraction of total population, taking into account the broad national demographic changes in labor-force participation rates; the regional equations also include a measure of business recessions, to capture what is known as the "discouraged worker" phenomenon -- people who cannot find work eventually stop looking.

The unemployment rate is forecast on the basis of labor force and total employment. This equation is not an identity, because the employment statistics are on an establishment (place of work) basis, and exclude agriculture and self-employment, while the labor force and unemployment rate data come from Current Population Survey. This is a household (place of residence) survey, and counts all forms of employment (including even temporary absence from a job due to strikes).

Housing

Housing is modeled in the RIS system using a modified stock-adjustment method. First, a time series was created for the total stock of homes (including mobile homes) by state, using the 1960, 1970, and 1980 Census, together with data on housing starts and mobile home shipments. The implied depreciation rate, which is affected by the actual history of conversions as a proportion of stock, is subject to the forecasters' judgment regarding likely future conversion rates.

Second, an equation was estimated for the actual stock, using population aged 18 to 64, and a composite measure of affordability. This includes average regional household income, interest rates, and regional home prices. This equation was then solved over history, to yield an estimate of the desired, or trend, housing stock.

Total housing starts are estimated on the basis of the gap between the desired and actual stocks, together with affordability (both a long-term moving average and short-term variations around the moving average). Also included is a speculation variable, modeled as the latest four-quarter increase in the desired stock (demand). Thus if demand has been increasing rapidly, builders may keep on building, even after the underlying demographics have turned down. In states where this is an important term in the equation, relatively large cycles may be observed in housing starts.

Total housing starts are divided into singles and multi based both on trends in the national mix, and on regional average incomes. It is assumed that single-family homes are the generally preferred form of housing, and that higher incomes will bring more singles, other things being equal.

Retail Sales

The RIS models include retail sales (durables and nondurables) for the nine regions. Details have now been added for all those states for which data are published, using each state's share of the region's disposable personal income to forecast changes in its share of regional retail sales. Estimates were also made of the implied retail sales in the non-reporting states, so as to ensure that the state and regional forecasts are both realistic and consistent. The state forecasts, like the existing regional series, are broken down into durables and nondurables, since sales in these two major categories respond to different influences, particularly in terms of their behavior over the business cycle.

Consumer Prices

Consumer prices indices do not exist at the state level, despite a widespread need for information on relative inflation in different parts of the country. DRI already forecasts those CPIU's that exist for major metropolitan

areas, and has now extended the coverage by using available data on consumer expenditure by region to construct state indices.

These are not based on local price information, but instead utilize information on typical household budgets in the four Census Regions, by size class of metropolitan area. This makes possible the calculation of different weights for the components of the CPI in each state, depending on its Census Region and the sizes of the metropolitan areas in the state.

These weights are applied to the national components of the CPI, except that state home prices are used for housing costs. The indices also include the existing forecasts of the 28 published metropolitan CPIU's, weighted by the population of the area relative to its state. The entire system of state and metropolitan indices thus represents a consistent set of indicators of relative rates of inflation; it must be noted, however, that they do not measure relative living costs at one point in time, since they do not embody state-by-state statistics.

DRI TRANSPORTATION SECTOR MODEL METHODOLOGY

The Transportation Sector of the U.S. Energy Model is a tool for forecasting vehicle demand for oil or, more specifically, motor fuels. With this model, DRI/McGraw-Hill tracks the stock, usage, and fuel efficiency characteristics of cars and three classes of trucks.

It is a vintage capital stock model, formulated algebraically rather than econometrically. For each vehicle category included, the model endogenously forecasts the capital stock, miles traveled, fuel use, and both new car and fleet-wide fuel efficiency for both gasoline- and diesel-fueled vehicles. The model is capable of examining dynamic adjustments to policies acting through traditional macro-economic variables, as well as policies directly affecting technological characteristics of the vehicle stock.

This model is premised on the notion that the demand for motor fuels is derived from the demand for travel and consumer's preferences toward particular vehicles. Consumers determine the level of travel as well as the vehicle stock composition through their purchase decisions. The stock composition, associated efficiency characteristics, and vehicle usage patterns thereby determine the level of fuel consumption. Both vehicle purchase patterns and travel decisions are derived within the model as functions of economic activity and fuel prices.

Vehicle Sales

The process of determining fuel consumption begins with consumers' vehicle purchase decisions, particularly the timing of the purchase and the type of vehicle bought. These decisions are based upon the prevailing macroeconomic environment and the price of fuels. Total sales of imported cars, domestic cars, light trucks (0 to 10,000 lbs.), medium trucks (10,001 to 33,000 lbs.), and heavy trucks (>33,000 lbs.) are obtained from DRI's Automotive and U.S. Macroeconomic Services. These sales figures are then disaggregated between gasoline- and diesel-fueled vehicles.

To accomplish this disaggregation, the diesel percentage of sales in each vehicle class is defined exogenously, based on historical

patterns and expected future behavior. We apply these diesel percentages to their respective classes, yielding the diesel-fueled share of vehicle sales for each class. The gasoline-fueled share is then calculated as total sales, less diesel-fueled sales, for each vehicle class.

Although DRI's base case forecast for gasoline-diesel sales splits are determined through off-line analysis, changes in these shares occur endogenously in the model and are functions of the prices of gasoline and diesel fuel relative to their respective base case levels. Once completed, the sales pattern summarizes the level of vehicle sales within four classes of vehicles across two fuel-use categories.

Vehicle Stock

Once purchase decisions are determined, the vehicle stock in any given year is defined as a function of past sales patterns and the technological characteristics of those sales, as embodied in the survival probabilities associated with specific vehicle age groups. The vehicle stock in a particular class in any given year depends upon the number of vehicles sold in each of the previous N years (with N being 10 for cars, 14 for light trucks, 13 for medium trucks, and 12 for heavy trucks), and the probabilities that these vehicles will still be on the road in that year. For each vehicle class, a set of survival probabilities is determined empirically that reconciles previous year vehicle sales data with the historical vehicle stock. Thus, a fixed percentage of cars or trucks sold in any given year is expected to be in the stock at some time in the future. This percentage declines with greater vehicle age.

The product of sales and survival rates for each discrete age category is then summed to give the stock from year 1 to year N . Added to this is the stock of old vehicles, or all vehicles older than the N th year for each class. A certain percentage of each previous years' old stock (beginning with the last historically observed old stock) is assumed to be scrapped each year. This exogenously specified scrapage rate is based on past historical behavior and future expectations. Additionally, the previous years' N th old cars are added to the old stock so that retirements of and additions to the old stock occur simultaneously, though at varying rates.

Vehicle Miles Traveled

The total number of miles traveled by the stock of vehicles of a particular class and fuel-using type is determined as the product of the number of vehicles in that class' stock and the number of miles traveled per vehicle in that stock. Miles per vehicle traveled depends in large part upon the vehicle's age and class; the older the vehicle, the fewer miles it is driven each year, on average. Thus, miles traveled per vehicle varies across two dimensions: (1) the class of vehicle and (2) the age of the vehicles within that class.

In the transportation sector, baseline forecasts of usage rates (miles traveled per vehicle) by class and age are based upon changing economic conditions and vehicle operating cost per mile driven. Although the baseline miles per vehicle estimate may differ across vehicle ages and classes, it is not allowed to vary across fuel-type within a particular class or across age groups within that class. Miles traveled per vehicle class and age are allowed to change over time in accordance with historical patterns.

Total miles traveled per vehicle class is derived from the number of miles per vehicle and the total number of vehicles in the stock. Total miles traveled for a particular class is simply the sum of the number of vehicles of a particular age multiplied by the miles traveled per vehicle in the age group.

Vehicles usage rates are dependent primarily upon real costs per mile-driven and real per capita disposable income for cars and real GNP for trucks. The real cost per mile is defined by dividing real fuel prices (cents per gallon) by the vehicle efficiency (miles per gallon).

The usage rates for cars vary over the forecast according to changes in retail gasoline prices or per capita disposable income change. For light trucks, the basic formulation is the same. In the case of medium trucks, we assume that miles traveled per vehicle are a function of the weighted average of real diesel fuel costs per mile and real gasoline costs per mile and real gross national product. Heavy truck usage rates are a function primarily of real GNP. Changes in real diesel fuel costs impact heavy truck usage rates mainly through their influence on GNP and truck sales.

Fuel Consumption

Fuel consumption for a particular vehicle class and fuel type is derived by summing the result of vehicle sales times survival rate times usage rate divided by average miles per gallon (MPG) for each discrete age category including the stock of old vehicles. Total consumption by fuel type is the sum of fuel consumption for each of the four vehicle classes. Total motor fuel consumption is the sum of gasoline plus diesel fuel.

New-Vehicle Efficiency

Since fuel consumption is the product of miles driven and vehicle efficiency, an accurate estimation of new-vehicle fuel efficiencies is a critical component of the transportation sector model. As new vehicles are purchased and old ones retired, vehicle stock average efficiency changes. In a recent effort to improve the accuracy of this critical forecast element, DRI employed two alternative methods to analyze the responsiveness of new-vehicle MPG to changing prices, economic conditions and government policies.

The econometric approach estimated the relationship between new vehicle MPG and demographics as well as changes in real fuel prices. This method is included explicitly in the DRI Transportation Sector model. The second approach examined the cost to manufacturers of installing fuel saving technologies, and the incentives for consumers to switch market segments in response to higher gasoline prices or gas-guzzler taxes. The combination of traditional econometric analysis of the key historic price, economic and demographic variables and an engineering assessment of the technological costs and constraints to fuel economy improvement in each vehicle segment has yielded an improved method of forecasting new vehicle fuel efficiency.

In the econometric analysis, changes in the new domestic car MPG were regressed on changes in demographics and current and lagged changes in the logarithmic value of real gasoline prices. Furthermore, different MPG responses were estimated for positive and negative price changes.

A demographic filter variable was created to explain variations in new car MPGs due to shifts in the age distribution of the car-buying

population. Car buyers in the 20-24 age group, for example, tend to buy smaller, more fuel efficient cars than buyers in the 35-40 population segment, where families usually dictate the need for a larger car; younger buyers also tend to have fewer cars per household. To approximate this demographic impact on MPG choice, we derived a weighted average of approximated 1989 MPG preferences. Weights are based on population shares within 10 age groups, adjusted by approximate vehicle ownership percentages within each group. While a one-to-one relationship is expected between the actual on-road new car MPG and the demographic variable, the coefficient on demographics in the regression analysis was constrained to 1.15 since the EPA-rated MPG is typically 15% higher than the on-road new car fuel-economy.

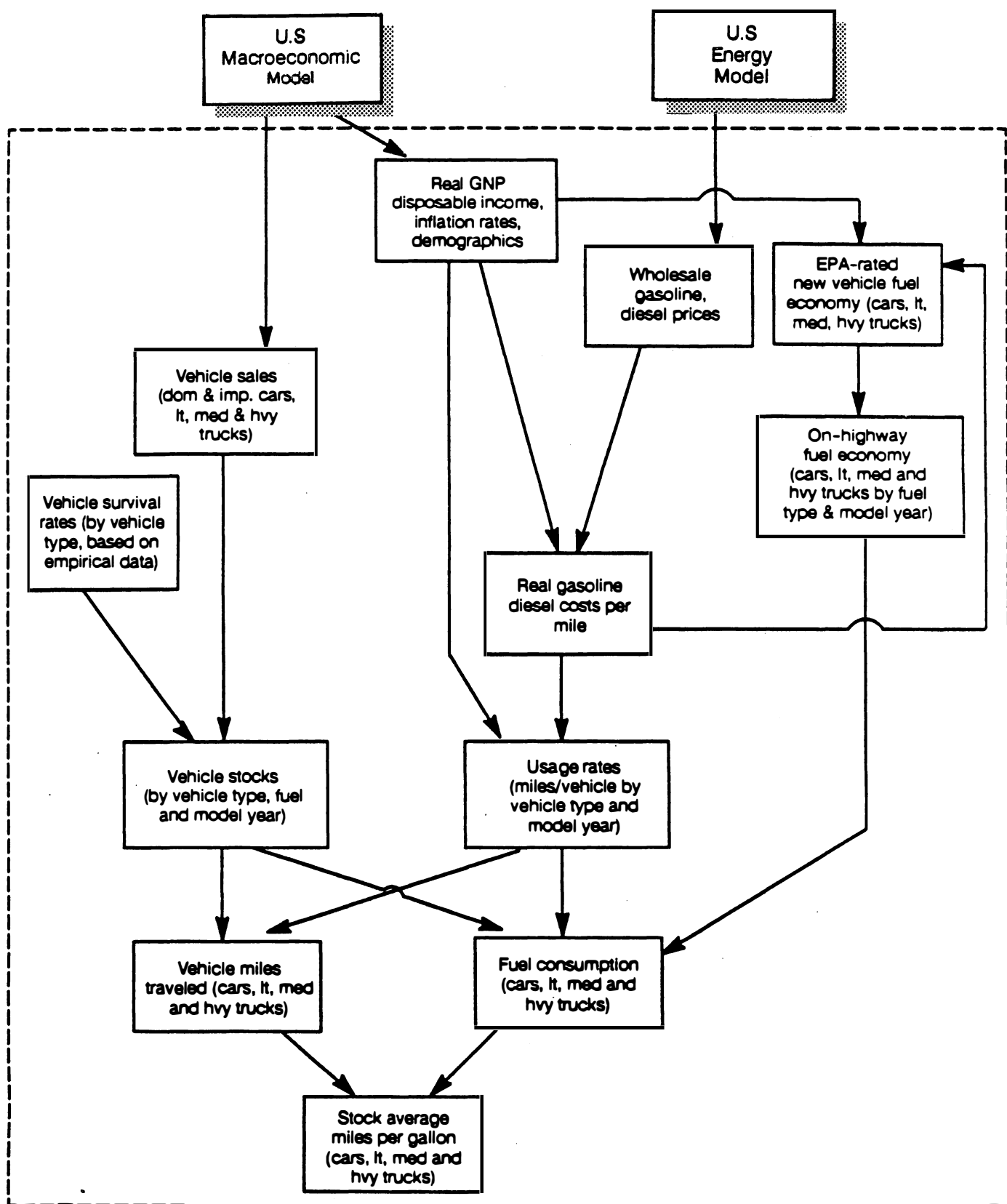
Modeling changes in MPGs as a function of changes in the log of the real gasoline price provides a structure in which continued improvements in MPGs in response to continued

price increases become increasingly more difficult. To the same MPG improvement as when real gasoline prices rose from \$0.50 to \$1.00, for example, would require prices to rise from \$1.00 to \$2.00 or from \$2.00 to \$4.00.

The regression structure also allows the MPG response to price changes to vary depending on whether prices are increasing or decreasing. Intuition suggests that true technological advances simulated by increasing prices will not be abandoned when prices decline.

The constant term of the regression suggest new car efficiency improved 0.5 MPGs per year over the 1970-89 period, independent of demographics or price changes. MPG changes resulting from price increases are 3 times as large as from price decreases. MPGs response to price changes in the current year and in 3 previous years. A 50% increase in the real gasoline price results in a 4.2 MPG gain within four years; a 50% cut in prices produces a 2.4 MPG drop.

CHART 1
DRI U.S. ENERGY MODEL TRANSPORTATION SECTOR STRUCTURE
 (on-highway section)



CHAPTER THREE

MODEL ASSUMPTIONS FOR REFERENCE CASES

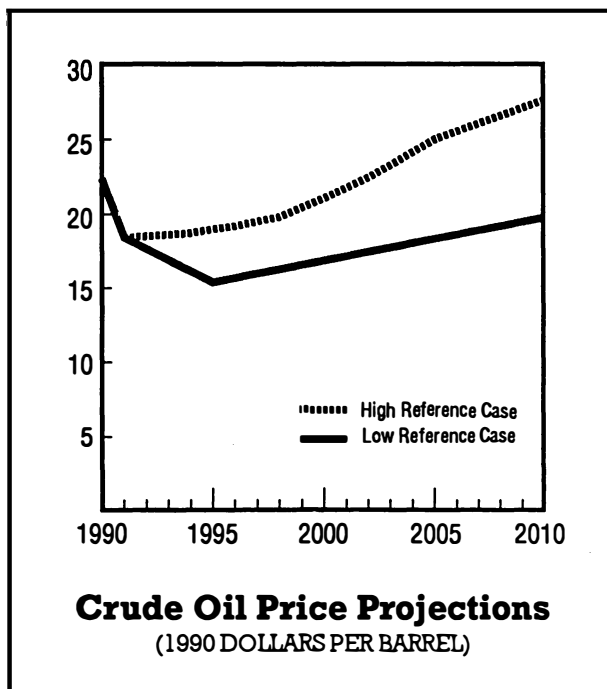
WORLD AND U.S. OIL PRICES

Crude Oil Prices

- Energy Overview Model uses two price series for crude oil
 - U.S. Refiner's Acquisition Cost of Crude (RACC)

– Lower-48 producers' wellhead oil price

- U.S. RACC price is used as basis for fuel oil product prices. RACC price projections for the NPC Reference Cases were prepared by DRI/McGraw-Hill.



U.S. Refiners Acquisition Cost of Crude

Year	High Reference Case		Low Reference Case	
	RACC (\$90/BBL)	Ann. Growth Rate (%)	RACC (\$90/BBL)	Ann. Growth Rate (%)
1990	\$22.32	—	\$22.32	—
1991	18.38	—	18.38	—
1995	19.01	0.9%	15.50	-4.2%
2000	21.10	2.1%	17.00	0.5%
2005	25.14	3.6%	18.50	1.7%
2010	27.85	2.8%	20.00	1.6%

- Lower-48 wellhead price is based on historical relationship to RACC:

Lower-48 WHD = $0.96 \times (\text{U.S. RACC}) - \$0.03/\text{BBL}$

Lower-48 wellhead price used in producer investment analysis

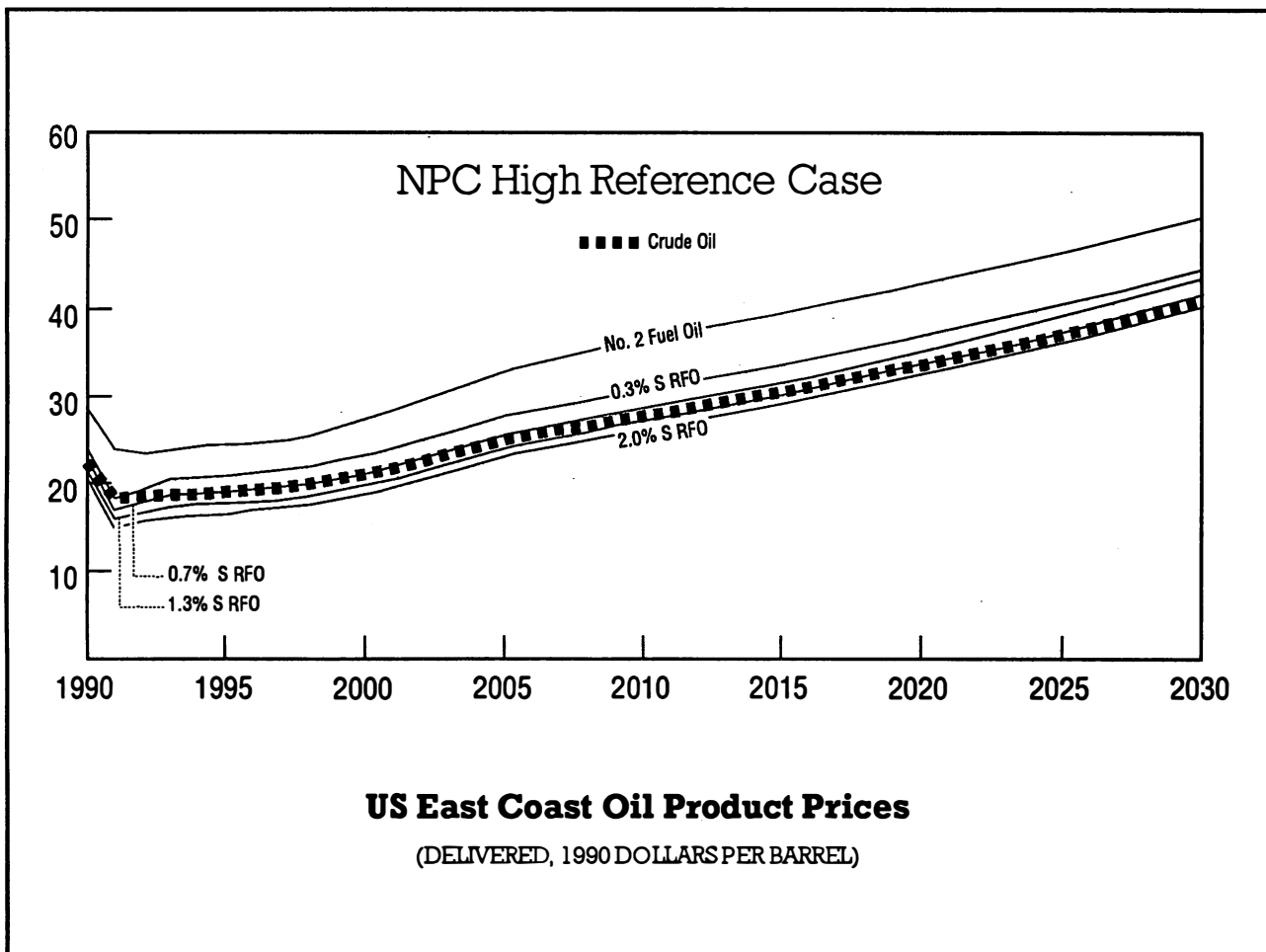
Fuel Oil Product Prices

- Alternative fuel oils represented in Energy Overview Model by 4 grades of residual fuel oil and by distillate:
 - High Sulfur RFO = 2.0%S and 1.3%S
 - Low Sulfur RFO = 0.7%S* and 0.3%S
- Fuel oil prices reflect price as delivered to end-user's "burnertip," including purchase price, delivery charges, and ad valorem taxes when applicable.
- Specified by sulfur grade for each year in forecast period:
 - Separate specifications for U.S. East Coast versus Region 9 (California, Arizona, and Nevada)
 - Regional variability added to determine final prices in each of the 10 demand regions.

*This class represents 0.5%S in Region 9 (California, Arizona, and Nevada).

Fuel Oil Price Scenario

- General outlook for world oil markets in NPC Reference Cases:
 - Growing oil product demand and refinery runs worldwide
 - Shift toward lighter product barrel, reduced demand for high sulfur products
 - Potential for declining value of high-sulfur fuel oils and possible trend toward increased low/high sulfur product price differentials over time
- Low-sulfur (0.3% S) residual fuel oil price projections prepared by DRI/McGraw-Hill for each Reference Case. Stated as New York Harbor Spot Cargo Prices.
- High-sulfur product price projections developed from DRI 0.3% S series assuming low/high sulfur price differentials of \$4-5/BBL as specified by NPC Demand & Distribution Group.



Delivered Fuel Oil Prices

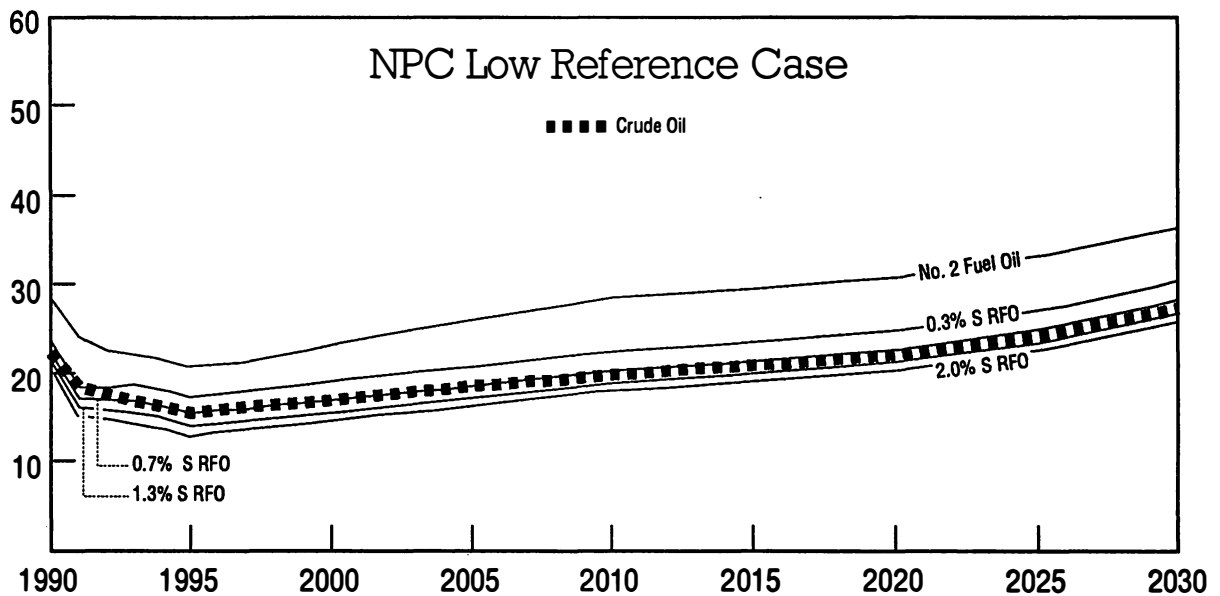
- Delivered oil product prices estimated by EEA from wholesale-level product price projections by sulfur-content plus regional transportation cost algorithms
- Model distinguishes two classes of fuel oil prices:
 - Large end-user price, applicable to electric utilities and largest industrials taking direct delivery by waterway
 - Retail industrial price for product supplied through oil jobbers, applicable to most of industrial sector
- Retail industrial prices start at \$0.80/BBL above large end-user price based on terminaling and land transportation costs for oil jobbers. A distribution cost curve for residual fuel oil is reflected for increasing consumption levels.

Comparison Of Crude Oil And Oil Product Price Projections

(\$1990 PER BARREL)

	1995	2000	2010
Crude Oil			
NPC High Reference Case	19.01	21.10	27.85
NPC Low Reference Case	15.50	17.00	20.00
Low Sulfur (0.3%) Residual Fuel Oil*			
NPC High Reference Case	20.94	23.41	30.84
NPC Low Reference Case	17.29	19.14	22.68
High Sulfur (2.0%) Residual Fuel Oil*			
NPC High Reference Case	16.50	18.95	26.41
NPC Low Reference Case	12.84	14.65	18.22
Low/High Sulfur Premium			
NPC High Reference Case	4.44	4.46	4.43
NPC Low Reference Case	4.45	4.49	4.46

* Delivered to larger end-users from New York Harbor (East Coast) Market. DRI wholesale level projections adjusted to delivered basis by EEA.



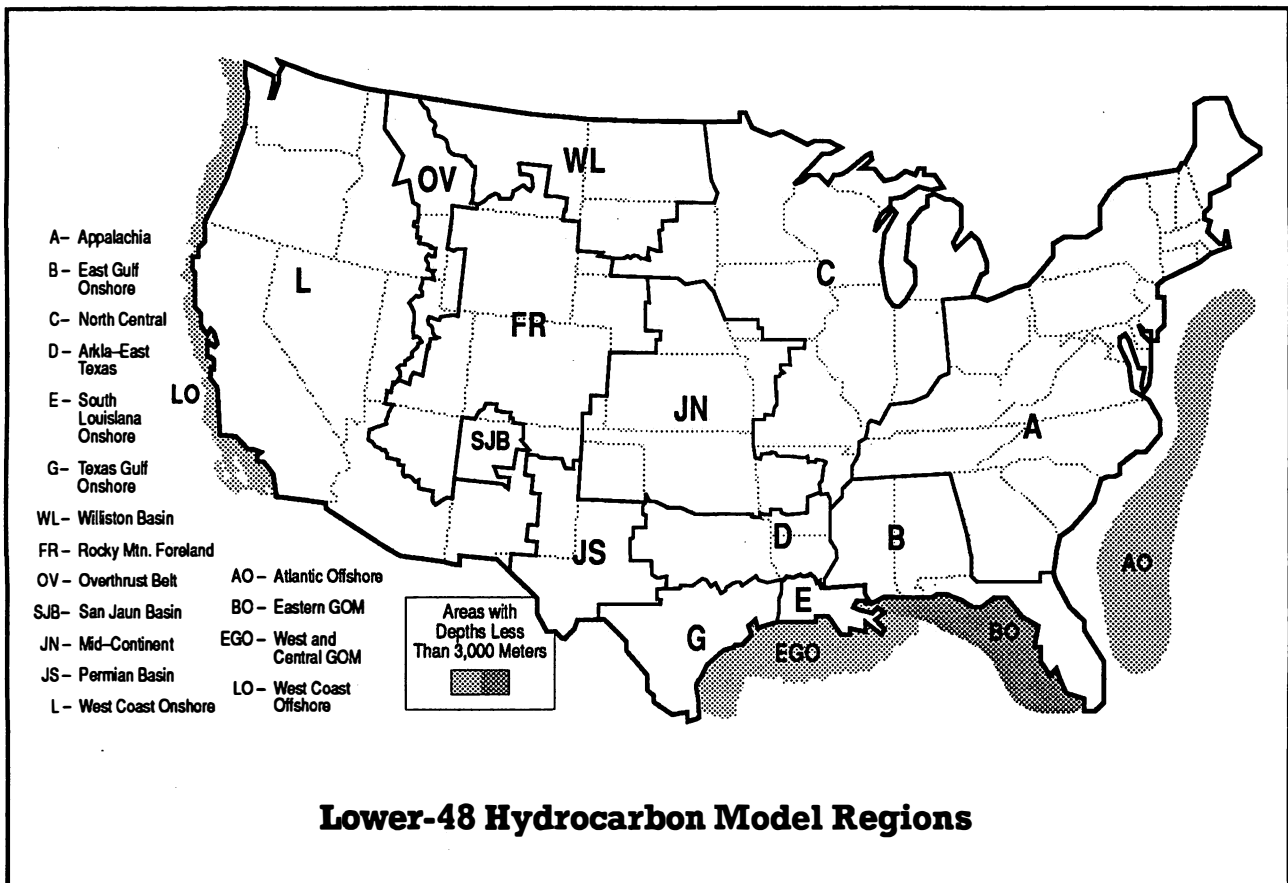
US East Coast Oil Product Prices

(DELIVERED, 1990 DOLLARS PER BARREL)

NATURAL GAS SUPPLY

Characterization Of ED&P Process

- New Field Exploration
 - Regional, by depth interval
 - Remaining resource base stated in terms of number, size and type of remaining fields
 - Pattern of discovery determined by EEA's "double exponential" find-rate equation
 - Representation of development stage includes number, timing and productivity of producing wells in each field
- Normal Reserve Appreciation in Existing Fields ("Probables")
 - Regional, by depth interval
 - Represented independently for oil versus gas fields
 - Characterized by old field exploratory drilling findrates, development drilling recoveries and well production profile
 - Model maintains inventory of probables, which turn over each year as resource is proved and new fields are discovered



- Unconventionals: Coal Bed Methane, Devonian Shale, Antrim Shale, Tight Gas, In-fill Drilling
 - Represented in "Enhanced Recovery Module"
 - Each "cell" in the ERM is for a specific area/formation/depth.
 - Characterized by average well productivity, decline rates, drilling costs, depletion effects, etc.
 - Up to three technology scenarios can be specified for each cell. Market shares are exogenous or endogenous (e.g., based on IRR or level of experience).
- Alternative Resource Base Options
 - New Fields: low, middle and high scenarios provided for each region/depth
 - Old Fields: specified as any fraction of default values
 - Unconventionals: specified as any fraction of default value for each "cell"

Recoverable Lower-48 Resource Base As Of 1/1/91

(TCF)

NPC Reference Cases

Resource Category	Current Technology	Advanced Technology
High Perm Nonass.	326.4	359.0
Low Perm Nonasso.	53.6	80.4
Asso.- Diss.	48.9	53.8
Total New Fields	428.9	493.2
High Perm Nonass.	166.0	182.6
Low Perm Nonasso.	30.4	33.5
Asso.- Diss.	18.4	20.2
Total Appreciation	214.8	236.3
Shale	37.1	57.2
Coalbed Methane	62.4	97.8
Tight Gas	148.4	235.2
Low Btu Gas	15.0	15.0
Undiscovered Total	906.7	1134.7

Lower-48 Gas Resource Summary By Region:

Base Technology

(TECHNICAL RECOVERY, DRY BCF AS OF 1/1/91)

		A	B	C	D	E	G	WL	FR	SJB
Undiscovered Nonassociated										
1. High perm	New Fields	19,990	10,036	6,137	11,227	14,760	36,548	1,315	18,972	870
	Old Fields	922	4,166	1,951	7,189	18,838	25,904	246	2,276	289
	Total	20,912	14,202	8,088	18,416	33,598	62,452	1,561	21,248	1,159
2. Low perm	New Fields	3,386	0	0	4,211	0	7,143	386	26,414	1,305
	Old Fields	0	0	0	4,224	0	5,501	275	7,297	6,473
	Total	3,386	0	0	8,435	0	12,644	661	33,711	7,778
3. Devonian Shale		26,626	0	10,523	0	0	0	0	0	0
4. Coalbed Methane		9,440	6,527	0	0	0	0	0	24,879	21,590
5. Tight		10,545	0	0	18,982	0	5,751	0	89,930	0
6. Low Btu Gas		0	0	0	0	0	0	0	14,960	0
Subtotal - Nonassoc.		70,909	20,729	18,611	45,833	33,598	80,847	2,223	184,728	30,527
Undiscovered Associated-Dissolv.										
7.	New Fields	213	872	2,343	3,085	435	2,350	891	3,212	976
	Old Fields	570	495	704	2,058	739	1,543	526	945	190
Subtotal - Assoc.-Dissolv.		783	1,367	3,047	5,143	1,174	3,893	1,417	4,157	1,166
Total Undiscovered 1/1/91		71,692	22,097	21,658	50,976	34,772	84,739	3,640	188,885	31,693
Historical Ultimate Recovery *										
Nonassociated		43,030	11,917	2,430	59,098	83,545	104,349	3,110	25,409	29,496
Associated-Dissolved		3,251	2,342	3,154	18,605	16,926	33,902	2,181	7,361	739
Total Ult. Recovery 1/1/91		46,281	14,259	5,584	77,703	100,471	138,251	5,291	32,770	30,235
All Time Recovery **		117,973	36,356	27,242	128,679	135,243	222,990	8,931	221,655	61,928

Lower-48 Gas Resource Summary By Region:

Advanced Technology

(TECHNICAL RECOVERY, DRY BCF AS OF 1/1/91)

		A	B	C	D	E	G	WL	FR	SJB
Undiscovered Nonassociated										
1. High perm	New Fields	21,989	11,040	6,751	12,350	16,236	40,203	1,447	20,869	957
	Old Fields	1,015	4,583	2,146	7,908	20,722	28,494	271	2,504	318
	Total	23,004	15,623	8,897	20,258	36,958	68,697	1,718	23,373	1,275
2. Low perm	New Fields	5,079	0	0	6,317	0	10,715	579	39,621	1,958
	Old Fields	0	0	0	4,646	0	6,051	303	8,027	7,120
	Total	5,079	0	0	10,963	0	16,766	882	47,648	9,078
3. Devonian Shale		42,475	0	14,747	0	0	0	0	0	0
4. Coalbed Methane		15,104	10,385	0	0	0	0	0	39,399	32,938
5. Tight		17,932	0	0	29,122	0	9,385	0	141,231	0
6. Low Btu Gas		0	0	0	0	0	0	0	14,960	0
Subtotal - Nonassoc.		103,594	26,008	23,644	60,342	36,958	94,847	2,600	266,611	43,291
Undiscovered Associated-Dissolv.										
7.	New Fields	234	959	2,577	3,394	479	2,585	980	3,533	1,074
	Old Fields	627	545	774	2,264	813	1,697	579	1,039	209
Subtotal - Assoc.-Dissolv.		861	1,504	3,351	5,658	1,292	4,282	1,559	4,572	1,283
Total Undiscovered 1/1/91		104,455	27,512	26,995	66,000	38,250	99,129	4,159	271,183	44,573
Historical Ultimate Recovery *										
Nonassociated		43,030	11,917	2,430	59,098	83,545	104,349	3,110	25,409	29,496
Associated-dissolved		3,251	2,342	3,154	18,605	16,926	33,902	2,181	7,361	739
Total Ult. Recovery 1/1/91		46,281	14,259	5,584	77,703	100,471	138,251	5,291	32,770	30,235
All Time Recovery **		150,736	41,771	32,579	143,703	138,721	237,380	9,450	303,953	74,808

Lower-48 Gas Resource Summary By Region:

Base Technology

(TECHNICAL RECOVERY, DRY BCF AS OF 1/1/91)

		OV	JN	JS	L	BO	EGO	LO	AO	TOTAL
Undiscovered Nonassociated										
1. High perm	New Fields	11,462	36,930	20,808	15,236	13,899	85,511	6,193	16,497	326,391
	Old Fields	7,146	26,419	13,558	2,455	3,232	51,129	295	0	166,015
	Total	18,608	63,349	34,366	17,691	17,131	136,640	6,488	16,497	492,406
2. Low perm	New Fields	0	8,394	2,332	0	0	0	0	0	53,571
	Old Fields	0	2,653	4,007	0	0	0	0	0	30,430
	Total	0	11,047	6,339	0	0	0	0	0	84,001
3. Devonian Shale		0	0	0	0	0	0	0	0	37,149
4. Coalbed Methane		0	0	0	0	0	0	0	0	62,436
5. Tight		0	10,842	12,390	0	0	0	0	0	148,440
6. Low Btu Gas		0	0	0	0	0	0	0	0	14,960
Subtotal - Nonassoc.		18,608	85,238	53,095	17,691	17,131	136,640	6,488	16,497	839,392
Undiscovered Associated-Dissolv.										
7.	New Fields	747	5,455	3,574	2,294	79	15,046	6,818	516	48,906
	Old Fields	424	1,507	3,415	398	0	4,470	401	0	18,385
Subtotal -Assoc.-Dissolv.		1,171	6,962	6,989	2,692	79	19,516	7,219	516	67,291
Total Undiscovered 1/1/91		19,779	92,200	60,084	20,383	17,210	156,156	13,706	17,013	906,684
Historical Ultimate Recovery *										
	Nonassociated	4,296	153,514	42,334	10,123	4,832	116,023	829	0	694,334
	Associated-Dissolved	321	38,778	49,702	23,485	0	19,989	2,851	0	223,588
Total Ult. Recovery 1/1/91		4,617	192,292	92,036	33,608	4,832	136,012	3,680	0	917,922
All Time Recovery **		24,396	284,492	152,120	53,991	22,042	292,168	17,386	17,013	1,824,606

Lower-48 Gas Resource Summary By Region:

Advanced Technology

(TECHNICAL RECOVERY, DRY BCF AS OF 1/1/91)

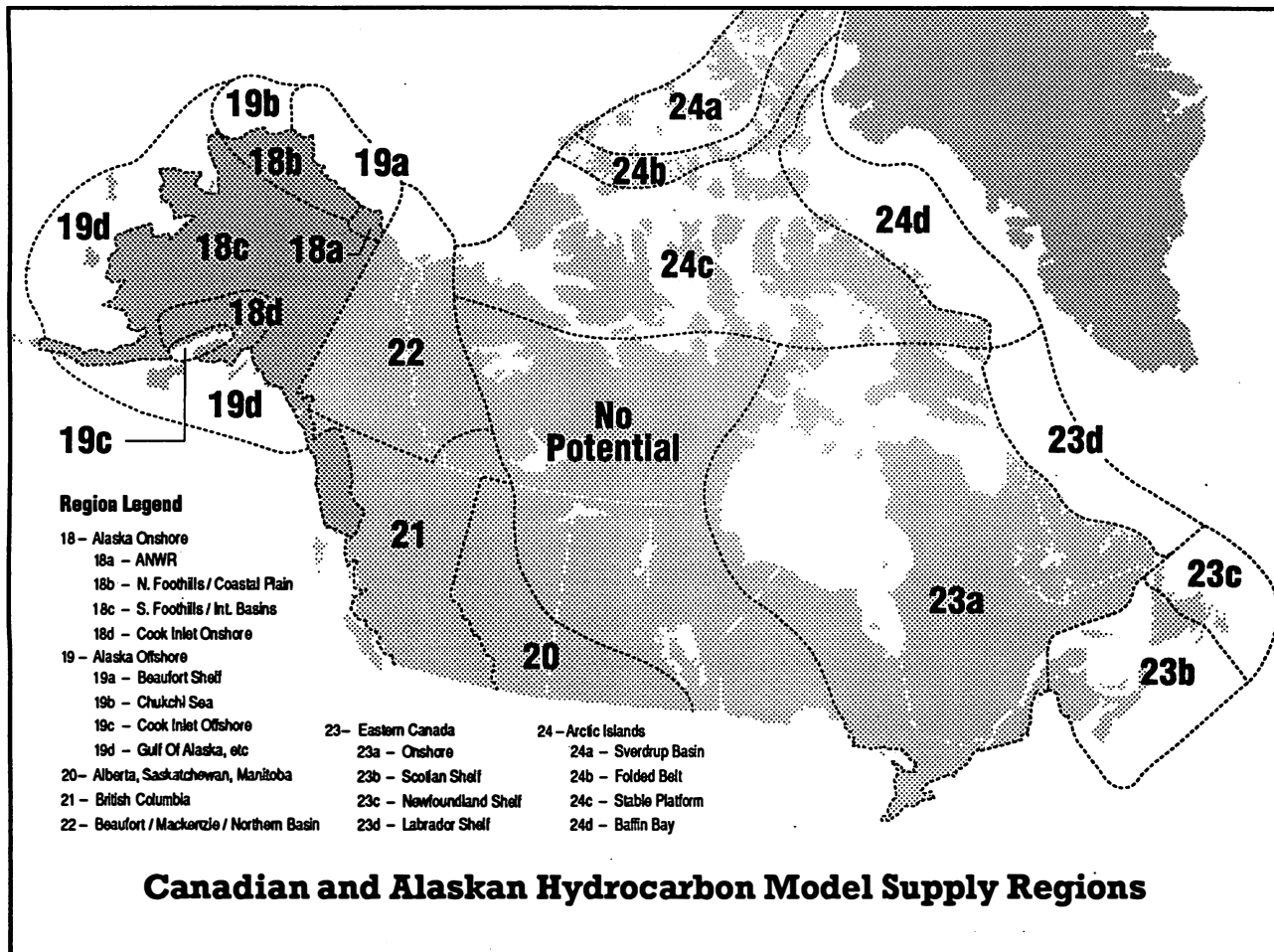
		OV	JN	JS	L	BO	EGO	LO	AO	TOTAL
Undiscovered Nonassociated										
1. High perm	New Fields	12,608	40,623	22,889	16,760	15,289	94,062	6,812	18,147	359,030
	Old Fields	7,861	29,061	14,913	2,700	3,555	56,242	324	0	182,617
	Total	20,469	69,684	37,802	19,460	18,844	150,304	7,136	18,147	541,647
2. Low perm	New Fields	0	12,591	3,498	0	0	0	0	0	80,357
	Old Fields	0	2,918	4,408	0	0	0	0	0	33,473
	Total	0	15,509	7,906	0	0	0	0	0	113,830
3. Devonian Shale		0	0	0	0	0	0	0	0	57,222
4. Coalbed Methane		0	0	0	0	0	0	0	0	97,826
5. Tight		0	17,429	20,105	0	0	0	0	0	235,204
6. Low Btu Gas		0	0	0	0	0	0	0	0	14,960
Subtotal - Nonassoc.		20,469	102,622	65,813	19,460	18,844	150,304	7,136	18,147	1,060,689
Undiscovered Associated-Dissolv.										
7.	New Fields	822	6,001	3,931	2,523	87	16,551	7,500	568	53,797
	Old Fields	466	1,658	3,757	438	0	4,917	441	0	20,224
Subtotal -Assoc.-Dissolv.		1,288	7,659	7,688	2,961	87	21,468	7,941	568	74,021
Total Undiscovered 1/1/91		21,757	110,280	73,501	22,421	18,931	171,772	15,077	18,714	1,134,710
Historical Ultimate Recovery *										
	Nonassociated	4,296	153,514	42,334	10,123	4,832	116,023	829	0	694,334
	Associated-dissolved	321	38,778	49,702	23,485	0	19,989	2,851	0	223,588
Total Ult. Recovery 1/1/91		4,617	192,292	92,036	33,608	4,832	136,012	3,680	0	917,922
All Time Recovery **		26,374	302,572	165,537	56,029	23,763	307,784	18,757	18,714	2,052,632

Canadian Natural Gas Resource Base

Current Technology
(BCF, AS OF 1/1/90)

	#20 Alberta, Sask, Manitoba	#21 B.C., S.M.L. Terr.	#22 Mackenzie/ Beaufort	#23 Eastern Canada	#24 Arctic Islands	Total
Reserve Growth.....	18,909	2,455	0	273	0	21,636
New Pools/fields	71,417	27,934	67,456	81,577	96,710	345,094
Coal Bed Methane	80,333	0	0	0	0	80,333
Tight Gas	54,700	0	0	0	0	54,700
Total Undiscovered	225,359	30,389	67,456	81,850	96,710	501,763
Producing Reserves	43,940	5,047	0	600	0	49,587
Undeveloped, Discovered Pools/fields	19,254	3,095	12,498	17,252	16,945	69,044
Total Discovered Reserves	63,194	8,142	12,498	17,852	16,945	118,631
Cumulative Production.....	56,129	7,701	0	833	0	64,663
All Time Ultimate	344,682	46,232	79,954	100,535	113,655	685,057

NOTES: Estimates of undeveloped reserves in Frontier areas are from EEA data base and do not necessarily match CPA or COGLA estimates.
Eastern offshore resources are NOT counted as established reserves by CPA.
Coal bed methane included only for plains portion of Alberta.



Canadian Natural Gas Resource Base

Advanced Technology

(BCF, AS OF 1/1/90)

	#20 Alberta, Sask, Manitoba	#21 B.C., S.M.L. Terr.	#22 Mackenzie/ Beaufort	#23 Eastern Canada	#24 Arctic Islands	Total
Reserve Growth.....	20,800	2,700	0	300	0	23,800
New Pools/fields	78,559	30,727	74,202	89,735	106,381	379,603
Coal Bed Methane	128,532	0	0	0	0	128,532
Tight Gas	89,400	0	0	0	0	89,400
Total Undiscovered	317,291	33,427	74,202	90,035	106,381	621,335
Producing Reserves	43,940	5,047	0	600	0	49,587
Undeveloped, Discovered Pools/fields	19,254	3,095	12,498	17,252	16,945	69,044
Total Discovered Reserves	63,194	8,142	12,498	17,852	16,945	118,631
Cumulative Production.....	56,129	7,701	0	833	0	64,663
All Time Ultimate	436,614	49,270	86,700	108,720	123,326	804,629

NOTES: Estimates of undeveloped reserves in Frontier areas are from EEA data base and do not necessarily match CPA or COGLA estimates.

Eastern offshore resources are NOT counted as established reserves by CPA.

Coal bed methane included only for plains portion of Alberta.

Producer Behavior

Producer Rate of Return

- Minimum rate of return on marginal investments (hurdle rate) used in "grading" each potential E&D investment.
- Hurdle rate expressed for model on a real (inflation adjusted), after-tax basis.
- NPC Reference Case used a 4 percent real, after-tax marginal rate of return. Realized average rate of return was well above this.
- Reflects inertia in industry, prevents unreasonable, dramatic shifts in location of activity between regions or depths.
- Model determines actual year-to-year change for each investment "cell" based on its profit index (internal rate of return minus hurdle rate).
- Inertial constraints for NPC Reference Case allow maximum of 30 percent upward and 40 percent downward change per year (see figure)

Inertial Constraints on E&D Activity

- Drilling activity limits imposed as maximum and minimum rates of change in drilling activity from prior-period levels.

Example Calculations For Real, After-tax Ror

Income Tax Rate: 37.0%
Inflation: 5.0%

Integrated Companies

	Nominal Rate	After-tax Rate	Real Rate *	D-E Ratio	Real, After-Tax Rate
Debt.....	10.5%	6.6%	1.5%	26.0%	0.4%
Equity	10.1%	10.1%	4.9%	74.0%	3.6%
					4.0%
Debt.....	10.5%	6.6%	1.5%	26.0%	0.4%
Equity	11.5%	11.5%	6.2%	74.0%	4.6%
					5.0%
Debt.....	10.5%	6.6%	1.5%	26.0%	0.4%
Equity	12.9%	12.9%	7.5%	74.0%	5.6%
					6.0%

Independents

	Nominal Rate	After-tax Rate	Real Rate *	D-E Ratio	Real, After-Tax Rate
Debt.....	12.0%	7.6%	2.4%	42.0%	1.0%
Equity	10.4%	10.4%	5.1%	58.0%	3.0%
					4.0%
Debt.....	12.0%	7.6%	2.4%	42.0%	1.0%
Equity	12.2%	12.2%	6.9%	58.0%	4.0%
					5.0%
Debt.....	12.0%	7.6%	2.4%	42.0%	1.0%
Equity	14.0%	14.0%	8.6%	58.0%	5.0%
					6.0%

* To convert to real:
real% = (nominal% - inflation%) / (1 + inflation%)

Producer Behavior (Continued)

Producer Price Expectations

- The model's DCF analysis of drilling investments is based on producer expectations for future oil and gas wellhead prices. Expected oil prices are based on the crude oil price scenario.
- Expected trajectory for gas prices is endogenously linked to model's current period solution for wellhead gas prices, but may be adjusted for long-run price expectations of producers.
- Long-run price expectations are determined by selection from model options:
 - Producers expect flat future prices. Current period's solution price is the expected price in all future years.
 - Producers have long-run expectations toward which prices will "ramp" from the current period's solution. Can be netback price from resid or other basis for expectations.

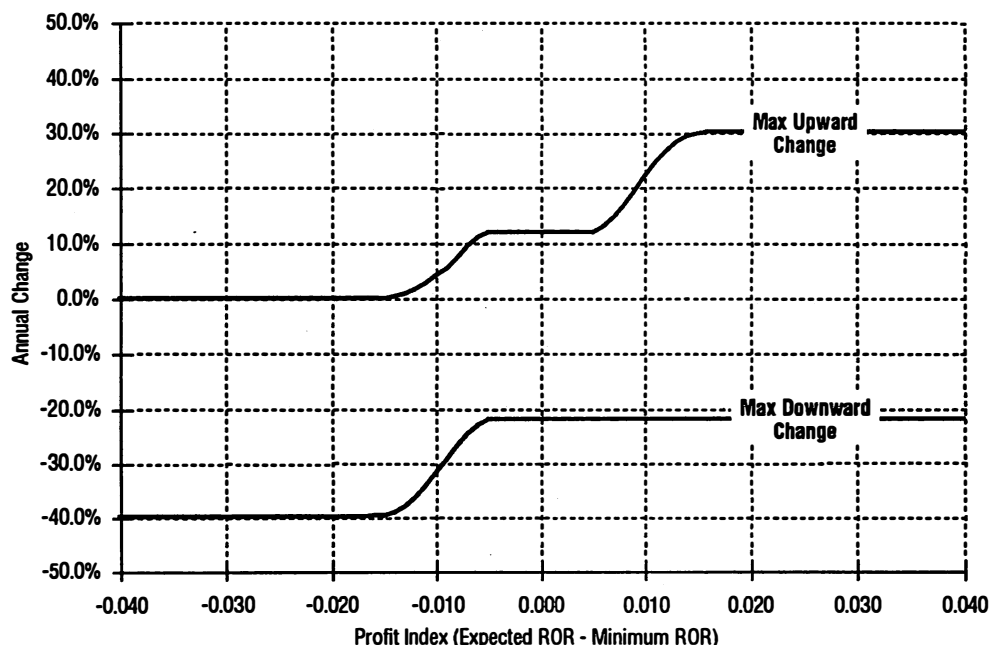


Illustration Of Supply Model Inertial Constraints

3) Producers assume an exogenous price path specified by user.

- Selection for NPC Reference Case was ramped expectation logic (option #2) to allow producers to anticipate future price changes. Expectations were adjusted to be consistent with the actual gas price results of the case, so that producers were effectively given "rational foresight" of future prices.

Drilling Costs

- Model's drilling costs are benchmarked to actual 1988 well cost data from Joint Association Survey (JAS).
- Drilling costs are projected endogenously in the model's solution as a national, annual drilling and completion (D&C) index where 1.00 = 1988 cost levels. D&C index includes all costs for exploration and development, except for offshore bonuses (calculated separately by model).
- Basis for EEA drilling cost projection is regression analysis over 20 year period of well cost per foot versus crude oil prices and rig counts.
- Although currently depressed, drilling costs must eventually increase toward full-cost recovery level for drilling services industry.
 - Must eventually reach revenue level sufficient to construct new rigs.
 - Varying assumptions on component costs at full-cost recovery level lead to range of 1.20-1.35 of 1988 costs for D&C index.
 - The full cost level is used to constrain drilling costs to reasonable levels in long-run.

Other Supply Assumptions

Speculative Lower-48 Gas Resources

- Reflects poorly understood, speculative resources not otherwise incorporated in model (e.g., some coalbed methanes in non-exploited basins).
- Set to zero for NPC Cases

Gas Supply Technology Improvement

- Improvement in new field exploration efficiency of 2 percent per year. Begin in 1991.
- Improvement in drilling technology leading to reductions in drilling cost index. Rate of improvement of 2.0 percent per year, beginning 1991.
- In conventional (high-permeability) fields, 5 percent increase in recovery of oil and gas by 2000 and another 5 percent by 2010.
- Advances in seismic technologies, well stimulation, and horizontal drilling increase recovery from low-permeability new fields by 50 percent by 2010.
- For deep water development, technological advances assumed to reduce cost of platforms by 25 percent.
- For coal bed methane, tight gas and Devonian shale, technological advances vary by cell and generally range for 30 percent to 60 percent improvement.

GAS IMPORT/ EXPORT TRADE

Gas Import/Export Trade

- Canadian gas imports into U.S. are endogenously determined in model.
- Mexican gas imports or exports are scenario assumptions set by the NPC Imports and Alaskan Workgroup. Assumptions for reference cases are shown below.

Mexican Gas (Imports) Exports

(BCF/YEAR)

	HIGH REF. CASE	LOW REF. CASE
1990	-16	-16
1991	-57	-57
1992	-110	-110
1993	-180	-180
1994	-220	-220
1995	-250	-250
1996	-270	-270
1997	-285	-285
1998	-300	-300
1999	-315	-315
2000	-330	-330
2001	-300	-345
2002	-270	-360
2003	-240	-380
2004	-210	-400
2005	-180	-420
2006	-135	-440
2007	-90	-455
2008	-45	-470
2009	0	-485
2010	100	-500
SUM(1990-2010)	-3,703	-6,588

Note: Negative volumes are U.S.
exports to Mexico

LNG Imports

- Based on an algorithm developed by Imports and Alaska working group. LNG algorithm constructed from considerations of current LNG contracts and anticipated new supply capacity (see below).
- Annual volume scenario implemented by iterative (offline) competition of LNG imports versus Lower-48 gas during series of runs leading to each case.
- Algorithm assumes that no LNG terminals would be constructed at new sites through 2010. No expansion of capacity at existing terminals required beyond minor increase in throughput at Everett (to 300 MMcfd after 2000).
- Annual LNG import volumes (Bcf) in NPC High Reference Case:

	1990	1995	2000	2005	2010
Existing Terminals					
Everett	40	81	113	113	113
Lake Charles	35	40	140	140	140
Cove Pt.	—	0	0	0	0
Elba Island	—	0	0	0	0
	75	121	253	253	253

LNG Market Clearing Prices

(1991\$)

	Min. Vol. (MMCF/D)	Max. Vol. (MMCF/D)	Price (\$/MCF)
Everett, MA			
Algeria (curr. supply)	110	110	—
Algeria (add'l supply)	0	130	2.50
Nigeria	0	70	2.55
Lake Charles, LA			
Algeria (curr. supply)	110	110	—
Algeria (add'l supply)	0	340	2.50
Venezuela	0	150	4.15
Venezuela	0	400	4.25
Cove Point, MD			
Venezuela	0	560	4.20
Elba Island, GA			
Venezuela	0	350	4.20
Venezuela	0	210	4.50

Note: Calculated prices have been rounded to the nearest nickel.

Calculation of Market Clearing Prices:

	Prod. & Liquef. ¹	Shipping ²	Regasif. ³	Total	Terminal Operating Volume (MMCF/D) ⁴
Everett:					
Nigeria	1.800	0.561	0.204	\$2.565	241-310
Lake Charles:					
Venezuela	3.310	0.742	0.081	\$4.133	451-600
Venezuela	3.310	0.742	0.189	\$2.241	601-1,000
Cove Point:					
Venezuela	3.310	0.643	0.230	\$4.183	0-560
Elba Island:					
Venezuela	3.310	0.603	0.290	\$4.203	0-350
Venezuela	3.310	0.603	0.596	\$4.509	351-560

¹ Contract price of \$1.80 FOB Nigeria; refer to LNG Appendix 3 Table 1 for Venezuela.

² Refer to LNG Appendix 3 Table 2; Nigeria trade uses a "used" ship; Venezuela uses new ships.

³ Refer to LNG Appendix 3 Table 3; average cost for specified terminal operating volume.

⁴ Refer to LNG Appendix 3 Table 3; Lake Charles and Elba Island have different prices for Venezuelan supply, since accepting full volumes (up to 560 MMCF/D) from Venezuela will require expansion of the terminal (i.e., additional capital expenditures).

LNG Imports

- Annual LNG import volumes (Bcf) in NPC Low Reference Case:

	1990	1995	2000	2005	2010
Existing Terminals					
Everett	40	52	113	113	113
Lake Charles	35	40	115	140	140
Cove Pt.	—	0	0	0	0
Elba Island	—	0	0	0	0
	75	92	228	253	253

ANGTS

- Alaskan Natural Gas Transportation System (ANGTS) authorized in 1977 for transporting Alaskan gas to Lower-48 U.S. markets. Construction of pre-build portion completed in 1982-83. In use for importing Canadian production, although low LF's on Eastern leg until 1988-1989.

- Project sponsors released new estimate of project costs in 1988. Reduced 45% to \$14.6 billion in 1988 dollars. Sponsors are claiming ability to be operational in mid-to late-1990's.
- ANGTS or other system could be part of opening Canadian frontier areas. Recent NEB forecast assumes MacKenzie Delta opened about 2000.
- NPC Case assumes that available North Slope gas will be used for pressure maintenance and enhanced liquids recovery through 2010.

Canadian Demand Assumptions

- High Reference Case Canadian demands are based on NEB forecast. Only changes for NPC were to backout fuel switching from gas to oil in later years. This added approximately 330 bcf of potential gas demand by 2010.
- Low Reference Case Canadian demands are based on reductions in energy demand that are similar to those assumed for U.S.

Assumptions For Energy Demand Growth

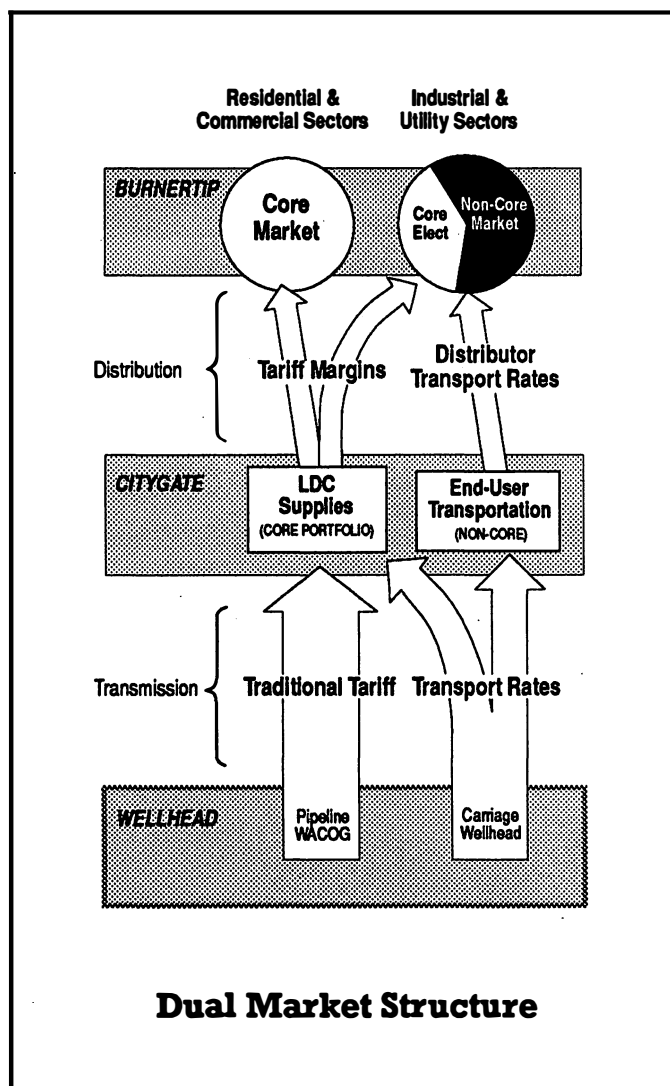
	(1990-2010)		
	NPC HIGH	NPC LOW	Ratio Low/High
U.S.			
Residential	0.5%	0.1%	0.21
Commercial	1.0%	0.8%	0.75
Industrial	1.3%	0.2%	0.18
Total Electricity (purchased)	1.7%	1.4%	0.79
Canada			
Residential	0.7%	0.1%	0.21
Commercial	1.2%	0.9%	0.75
Industrial	2.0%	0.4%	0.18
Total Electricity	1.8%	1.4%	0.77

Canadian Energy Demand For NPC Reference Cases

	High Reference Case				Low Reference Case			
	1990	2000	2010	Growth 1990-2010	1990	2000	2010	Growth 1990-2010
Residential								
Electricity	476	542	615	1.29%	476	527	580	0.99%
Oil Products	266	224	196	-1.52%	266	208	171	-2.19%
Natural Gas	538	621	658	1.01%	538	564	575	0.34%
LPG	19	21	23	0.96%	19	19	20	0.24%
Coal	2	1	1	-3.16%	2	1	1	-4.06%
Renew. & Other	93	97	99	0.31%	93	88	86	-0.38%
Total	1,394	1,506	1,592	0.67%	1,394	1,408	1,433	0.14%
Commercial								
Electricity	362	423	485	1.47%	362	408	454	1.13%
Oil Products	102	102	99	-0.13%	102	102	94	-0.42%
Natural Gas	349	406	453	1.32%	349	393	429	1.04%
LPG	22	23	23	0.26%	22	22	22	-0.06%
Coal	0	0	0		0	0	0	
Renew. & Other	2	3	5	4.96%	2	3	4	4.40%
Total	836	957	1,065	1.22%	836	927	1,002	0.91%
Industrial								
Electricity	627	805	972	2.22%	627	761	880	1.71%
Oil Products	310	376	409	1.40%	310	279	267	-0.74%
Natural Gas	875	1,130	1,340	2.15%	875	875	875	0.00%
LPG	26	29	33	1.27%	26	23	22	-0.83%
Coal, Coke	217	276	470	3.95%	217	242	307	1.76%
Renew. & Other	412	431	459	0.54%	412	360	300	-1.58%
Total	2,466	3,047	3,683	2.03%	2,466	2,540	2,650	0.36%
Transportation								
Electricity	3	6	9	5.92%	3	5	7	4.37%
Oil Products	1,791	1,901	2,012	0.58%	1,791	1,873	1,954	0.44%
Natural Gas	3	10	17	9.34%	3	10	17	9.21%
LPG	26	31	37	1.85%	26	31	36	1.71%
Coal	0	0	0		0	0	0	
Renew. & Other	0	0	0		0	0	0	
Total	1,822	1,948	2,075	0.65%	1,822	1,919	2,013	0.50%
Non-Energy								
Oil Products	333	404	481	1.85%	333	335	337	0.05%
Natural Gas	139	186	226	2.47%	139	150	158	0.67%
LPG	143	223	238	2.56%	143	164	166	0.74%
Total	616	813	945	2.17%	616	649	662	0.36%
Total End Use								
Electricity	1,468	1,776	2,081	1.76%	1,468	1,700	1,921	1.35%
Oil Products	2,802	3,007	3,197	0.66%	2,802	2,796	2,822	0.04%
Natural Gas	1,903	2,353	2,694	1.75%	1,903	1,992	2,054	0.38%
LPG	236	327	354	2.06%	236	259	266	0.60%
Coal	219	277	471	3.92%	219	243	308	1.73%
Renew. & Other	507	531	563	0.52%	507	452	390	-1.30%
Total	7,134	8,270	9,360	1.37%	7,134	7,442	7,760	0.42%
Electric Utility								
Natural Gas	97	81	116	0.90%	97	81	116	0.90%
Total Primary Gas Demand								
.....	2,000	2,434	2,810	1.72%	2,000	2,073	2,170	0.41%

Note: Gas and oil demands are absent any fuel switching from gas to oil.

REGULATORY AND TRANSPORTATION MARKET STRUCTURE



Regulatory Context

- NPC Reference Cases assume a flexible market structure and continuation of regulatory move toward deregulation.
- FERC transportation policy of Orders 436/500 continued. Total wellhead price decontrol by 1/1/93.
- General market outlook is for near-term success in resolving industry's gas contract problems:
 - Legacy of problem contracts essentially gone by 1990/91
 - All new gas contracts assumed to be market responsive — i.e., contain market out clauses and take-or-release provisions
- Pipeline/LDC contract relationships reformed in early 1990's through GIC's and Order 636
- FERC Order 636 was issued during study and was not explicitly simulated in modeling effort. Rate treatment was revised to approximate the impact on transport rates and pipeline revenues of the shift toward Straight Fixed Variable rate-design.

Market Structure

- All scenarios assume continuation of dual market structure:
 - LDC/tariff market of conventional gas utility sales under cost-of-service rates
 - End-user transportation market of spot gas sales under flexible T&D transport rates

LDC/Tariff Market

- Tariff market is served by an LDC portfolio of firm and spot gas supplies:
 - Pipeline purchases
 - Direct Canadian imports (e.g., PGT)
 - LT producer contracts
 - Spot market purchases
- Scenarios assume LDC portfolios change as bubble ends to reflect greater reliance on firm supplies.
- Scenarios also assume pipelines successful in stabilizing merchant function by early 1990's.

End-User Transportation

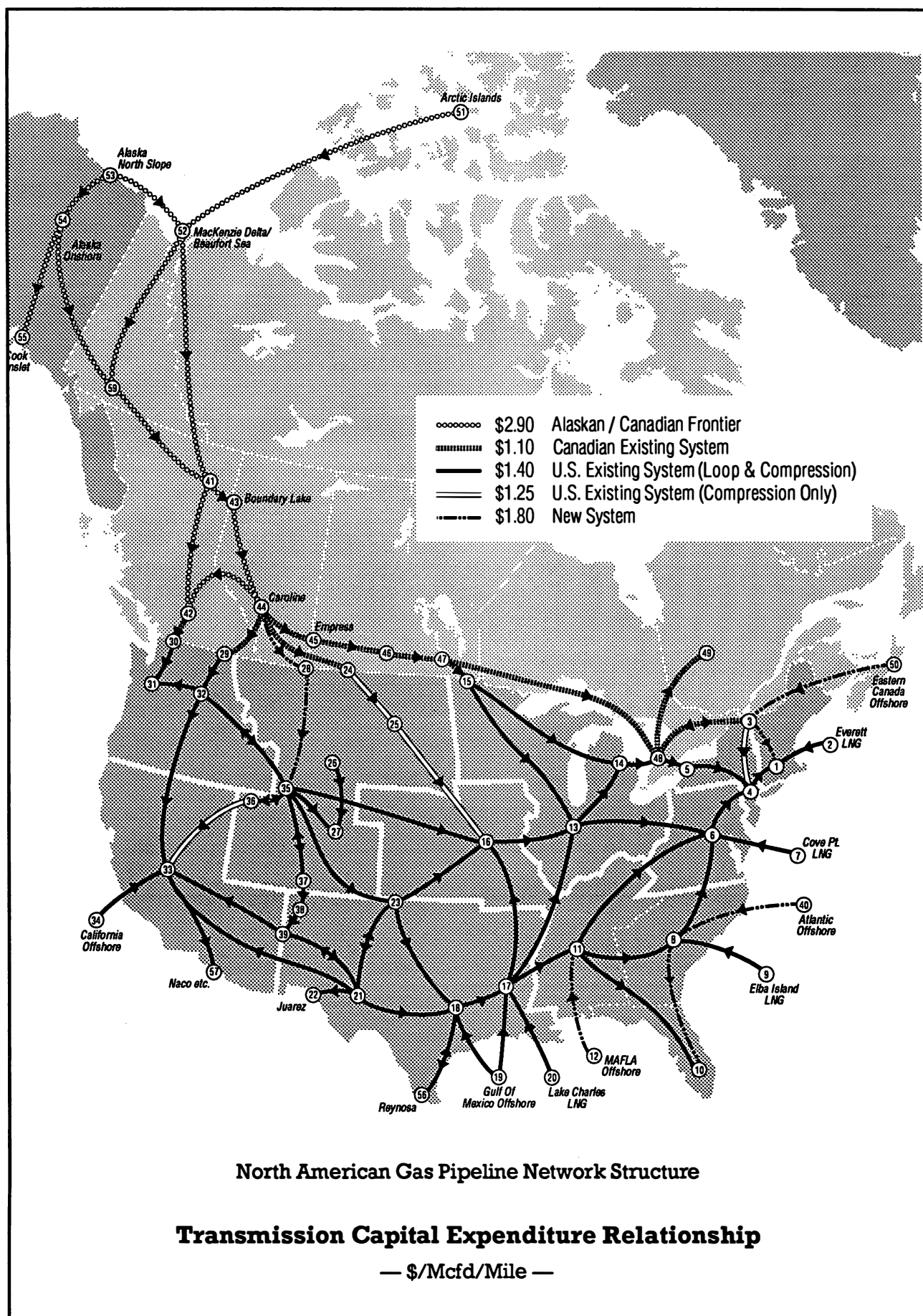
- End-user may enter transport market for two reasons:
 - Availability of lower priced gas compared to LDC's core-market tariff rates
 - Fuel switching pressures from lower-priced residual fuel oil
- First group (gas-on-gas competitive) includes higher-valued industrial user and distillate-competitive UEG load
 - Over forecast period tend to swing back to core market
 - UEG load (e.g., combined cycle units) assumed to stay on transport gas
- Second group (gas-on-oil competitive) allowed access to transport gas when needed to minimize fuel switching (no institutional barriers). Essentially a very flexible market tending to support demand

Transportation Discounting

- Pipelines and LDC's will discount interruptible transport (ITS) rates when necessary to compete for sales in end-user markets
- Discounting constrained by "floors" representing minimum (year-round) rates.
- Chosen to recover O/M and debt costs allocated to ITS; little or no return on/of capital
 - Pipeline floors vary by pipeline group, range \$0.25-\$0.40
 - LDC floors assumed \$0.20, representing rock-bottom rate
- The scenarios assume that interpipeline competition does not lead to significant discounting on transportation for LDC/Tariff market

Pipeline Capacity Expansion And Costs

- Capacity additions endogenously selected by EEA Pipeline Network Model. Objective is to minimize delivered gas cost at each point in network subject to capacity constraints, while satisfying demand.
- Pipeline capacity expansions determined from:
 - Announced expansion plans (through 1994)
 - Endogenous selection of long-term expansion options (generic plans)
- Costs of pipeline capacity expansions based on:
 - Costs and rates estimated by sponsors of announced projects
 - Generic cost algorithms developed by NPC T&S Group for construction cost per Mcfd of capacity per geographic mile of haul (see chart).
- Other capital expenditures for maintenance and refurbishment of existing transmission facilities based on scenario (time-phased schedule) developed by NPC T&S Group.



Network Nodal Structure

Lower-48 Nodes

NODE	NAME	SUPPLY	DEMAND
N1	NEW ENGL	—	ME, NH, VT, MA, CT, RI
N4	NY/NJ	Appalachia: NY	NY, NJ
N6	MID ATLANTIC	Appalachia: South	PA, DE, MD, VA, WV, KY
N8	SO ATL	—	NC, SC, GA
N10	FLORIDA	MAFLA – Florida	FL
N11	SO. EAST	MAFLA – MS/AL	MS, AL, TN
N12	NORPHLET	Norphlet	—
N13	MIDWEST	Midwest / Appalachia: Ohio	IN, IL, MI, WI, MN, OH
N16	CENTRAL	—	MO, IA, NE
N17	SO. LA	LA Gulf Onshore	AR, LA
N18	E. TEXAS	NE. TX / NO. LA & TX Gulf Onshore	E.TX
N19	Gulf Of Mexico	Gulf Of Mexico	—
N21	W. TEXAS	Permian Basin	W.TX, E.NM
N23	MID-CONT	Mid Continent	KS, OK
N25	GT PLNS Coal Gasification	Great Plains Coal Gasification	—
N26	HSM WL	Williston Basin	—
N27	MOUNTAIN	—	CO, UT, WY, MI, ND, SD
N31	PAC NW	Pacific: OR, WA	OR, WA, ID
N32	NPC / PGT	—	—
N33	SO PAC	Pacific: CA, AZ, NV	CA, AZ, NV
N34	HSM LO	Pacific Offshore	—
N35	OPAL WY	Rockies (HSM FR)	—
N36	HSM OV	Overthrust Belt	—
N37	HSM SJB	San Juan Basin (N)	—
N38	EPNG/SJ	San Juan Basin (S)	W.NM
N39	EPNG/TW	—	—
N40	Atlantic Offshore	HSM AO	—

Canadian/Alaska Nodes

NODE	NAME	SUPPLY	DEMAND
N41	BC (N)	HSM BC	—
N42	BC (S)	—	BC
N43	Boundary Lake	—	—
N44	Caroline	HSM ASM	Alberta
N45	Empress	—	—
N46	Saskatchewan	—	Saskatchewan
N47	Manitoba	—	Manitoba
N48	Ontario	—	Ontario
N49	Quebec	—	Quebec
N50	Eastern Canada	HSM EC	Atlantic
N51	Arctic Islands	HSM ART	—
N52	Mack / Beaufort	HSM NWC	—
N53	Alaska North Slope	HSM AKO	—
N54	Alaska Interior	HSM AK	—
N55	Alaska Cook Inlet	HSM AKO	Alaska

Canadian Imports

NODE	IMPORT LOCATION
N3	Phillipsburg / Cornwall
N5	Niagara
N14	St. Clair
N15	Emerson
N24	Monchy
N28	Wild Horse
N29	Kingsgate
N30	Huntingdon

Mexican Border Points

NODE	IMPORT LOCATION
N22	Juarez
N56	Reynosa
N57	Naco etc.

LNG Imports

NODE	TERMINAL LOCATION
N2	Everett
N7	Cove Point
N9	Elba Island
N20	Lake Charles

Pipeline Capacity Costs And Rates

NPC
T&S Choice

Capitalization Assumptions

Equity (% of capital)	30%
Return on Equity (AT)	13.5%
Cost of Debt (BT)	10.0%
Composite ROR (BT)	13.4

Ratemaking Assumptions

Useful Life	30 years
LF (%) for rate design	90%
Levelization of Rates	Over first 5 years
Incremental/Rolled-in	
Canada	rolled-in
U.S.	rolled-in

Pipeline Construction Costs

Standard	NPC T&S factors
Exceptions	Known projects

ENVIRONMENTAL REGULATION

Impact Of Pending Regulatory Activity On Gas And Competing Fuels

NSPS

- No new requirements. EPA not likely to revise or expand. EPA will look to BACT* and LAER** reviews of new equipment to tighten emission limits

ACID RAIN

- Focus of legislation is on reduction of SO₂/NO_x emissions from coal-fired units in electric utility sector.
- Control options will include scrubbing (FGD), coal switching, clean coal technologies.

- Oil-fired units will be affected in second phase (post-2000). Gas will have clear premium over fuel oil based on sulfur content.
- Emerging gas/coal technologies (cofiring, reburn) have potential to offer emission control option. Gas also valuable as back-up contingency control measure (FGD outages, higher power situations)
- States could be under pressure to cut oil sulfur limits applicable to non-utility sources.

* Best Available Control Technology

** Lowest Achievable Emissions Rate

Acid Rain

- Key provisions of Acid Rain law (Title IV):
 - Mandated reductions in emissions from fossil-fuel steam generators, 10 MM tons SO_x and 2 MM tons NO_x by 2000
 - Meet 2.5 lbs/MMBtu average in Phase I (by 1995 or 1996)
 - Meet 1.2 lbs/MMBtu in Phase II (by 2000 or 2001) with no (or limited) emissions increases allowed for units ≤1.2 lbs
 - Emissions allowances/trading system
 - No direct control of industrial sector sources, but may optionally participate in trading
- Key elements to reflect in an environmental scenario:
 - Higher electricity prices and impact on electricity demand growth
 - Gas/oil fuel switching constraints in utilities — e.g., emissions trading via SO_x control cost curve
 - Market size for gas/coal technologies
 - Potential for EPA to tighten air emissions regulations in the industrial sector in a future action

CNG Vehicle Scenario

- Reference Case based on estimating numbers of clean-fuel vehicles required by Mandated Programs (only) in four vehicle groups:
 - Urban buses
 - Fleet vehicles
 - Private autos (California only)
 - Some heavy-duty trucks
- Analysis based on simplified model of vehicle population dynamics: vehicles in operation, miles of travel, fuel consumption, scrappage, etc. Key variables are:
 - Extent of U.S. vehicle population in affected geographic areas

- New vehicle sales levels, fuel consumption per vehicle, vehicle lifetimes (turnover rate)
- Limiting provisions (e.g., fleet vehicle program limited to centrally-fueled fleets of 10 or more)
- CNG penetration rates in clean-fuel vehicle populations based on a positive outlook for CNG penetration versus other clean fuels:
 - 25% of urban buses
 - 25% in mandated fleet vehicle programs
 - 10% in California pilot program for private autos
 - 50% in other vehicle groups (e.g., school buses and heavy trucks)

Clean Fuel Vehicle Energy Consumption Scenario

(TBTU'S)

	Total	Urban Buses	School Buses	Fleet LDV/LDT	Calif Pilot Proj	Lt/Med MDTs	Other LDV/LDT
1985	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1990	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1992	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1993	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996	21.3	0.0	0.0	0.0	21.3	0.0	0.0
1997	39.5	0.0	0.0	0.0	39.5	0.0	0.0
1998	83.8	6.3	0.7	13.8	55.0	8.0	0.0
1999	157.5	12.6	1.3	39.7	88.1	8.0	0.0
2000	242.2	19.8	2.6	80.2	116.3	8.0	0.0
2001	301.9	27.0	4.0	99.9	140.5	8.0	0.0
2002	350.2	35.3	6.2	110.1	161.2	8.0	0.0
2003	396.2	43.6	8.5	121.4	178.8	8.0	0.0
2004	439.0	51.7	10.8	132.5	193.8	8.0	0.0
2005	471.5	52.2	13.1	143.8	206.4	8.0	0.0
2006	500.8	52.7	15.5	153.9	217.1	8.0	0.0
2007	528.1	53.3	17.9	164.0	226.0	8.0	0.0
2008	553.8	53.8	20.3	174.3	233.4	8.0	0.0
2009	577.7	54.3	22.7	184.5	239.4	8.0	0.0
2010	600.5	54.9	25.1	194.9	244.3	8.0	0.0

CNG Vehicle Natural Gas Consumption Scenario

(TBTU'S)

	Total	Urban Buses	School Buses	Fleet LDV/LDT	Calif. Pilot Proj	Lt/Med MDTs	Other LDV/LDT
CNG Penetration Among Clean-Fuel Vehicles		25.0%	50.0%	25.0%	10.0%	50.0%	0.0%
1985	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1986	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1987	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1988	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1989	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1990	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1991	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1992	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1993	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1994	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1995	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1996	2.1	0.0	0.0	0.0	2.1	0.0	0.0
1997	4.0	0.0	0.0	0.0	4.0	0.0	0.0
1998	14.9	1.6	0.4	3.5	5.5	4.0	0.0
1999	30.4	3.2	0.7	9.9	8.8	7.9	0.0
2000	49.6	5.0	1.3	20.1	11.6	11.7	0.0
2001	63.0	6.8	2.0	25.0	14.1	15.3	0.0
2002	74.3	8.8	3.1	27.5	16.1	18.7	0.0
2003	85.3	10.9	4.3	30.4	17.9	22.0	0.0
2004	95.9	12.9	5.4	33.1	19.4	25.1	0.0
2005	104.2	13.1	6.6	36.0	20.6	28.0	0.0
2006	111.9	13.2	7.8	38.5	21.7	30.8	0.0
2007	119.3	13.3	9.0	41.0	22.6	33.5	0.0
2008	126.5	13.5	10.2	43.6	23.3	36.0	0.0
2009	133.4	13.6	11.4	46.1	23.9	38.4	0.0
2010	140.1	13.7	12.6	48.7	24.4	40.7	0.0

Upstream Environmental Compliance Costs

- NPC environmental regulations compliance cost impact scenario based on analysis of four laws:
 - **Resource Conservation And Recovery Act (RCRA)**
 - **Safe Drinking Water Act (SDWA)**
 - **Clean Water Act (CWA)**
 - **Clean Air Act (CAA)**
- Also considered restrictions on wetlands drilling
- Costs put directly into Hydrocarbon Supply Model as capital costs or operating costs dollars per well, broken out by region and depth interval
- Over 30 different variables such as well depth, productivity, produced water ratio, disposal well ratio to producer, and production wells per gas plant were estimated for use in cost calculations
- Majority of compliance cost estimates were adapted from API reports,
- EPA reports on Clean Water Act costs and MMS reports on Clean Air Act costs were also utilized
- NPC "balanced" scenario is generally equivalent to the low impact cases sketched by the Department of Energy in their 1990 oil exploration and production report
 - Sum of all NPC "balanced" scenario costs generally add less than \$55,000 to the costs of new gas wells, \$125,000 to costs of new oil wells
 - Operating costs increased less than \$7,000 per year/gas well, \$4200 per year/oil well
 - Exception is Clean Water Act impact on shallow water offshore operations:
 - NPC scenario results in as much as \$130,000 per well increase in drilling costs,
- Other exceptions include much higher costs of CWA regulations in Louisiana, CAA regulations offshore California, and wetlands drilling costs in Louisiana
- Impact on production from existing completions considered in model of all existing U.S. gas wells
- Special attention paid to impact on Appalachian region and stripper well compliance costs
- **RCRA** - Capital costs incurred from \$10,000 to \$15,000/well (onshore) main cost is offsite drilling waste disposal. Other costs include evaporation pit closure, emergency pit upgrades, workover pit closure
- **SDWA** - Operating costs from 0 to \$4,000 per year/well (onshore) main cost is mechanical integrity pressure testing and logging of injectors
- **CWA** - Capital costs incurred \$2,500/well (onshore ex. La). Capital costs incurred up to \$120,000/well (onshore La). Offshore new well shallow water capital costs up to \$461,000 (oil), \$113,000 (gas). Offshore existing well shallow water capital costs up to \$28,000 (oil), \$17,000 (gas)
 - National Pollution Discharge permit costs \$2,500/well
 - Onshore Louisiana costs increased by cost of new injection wells required by ban on surface discharge of produced fluids Offshore costs driven by holding tank and treatment system for produced waters - draft scenario uses national average water production for oil and gas wells
- **CAA** - Capital costs incurred from \$3,000 to \$12,000/well (onshore) main cost is compression cost increase because of air toxics emissions controls
- Capital costs incurred up to \$125,000/well (offshore Calif) main cost increase because of air toxics emissions controls during platform construction, development drilling and operation
- Wetlands Drill Site Restrictions — Capital costs increase from \$100 to \$120,000 per gas well due to increased directional drilling

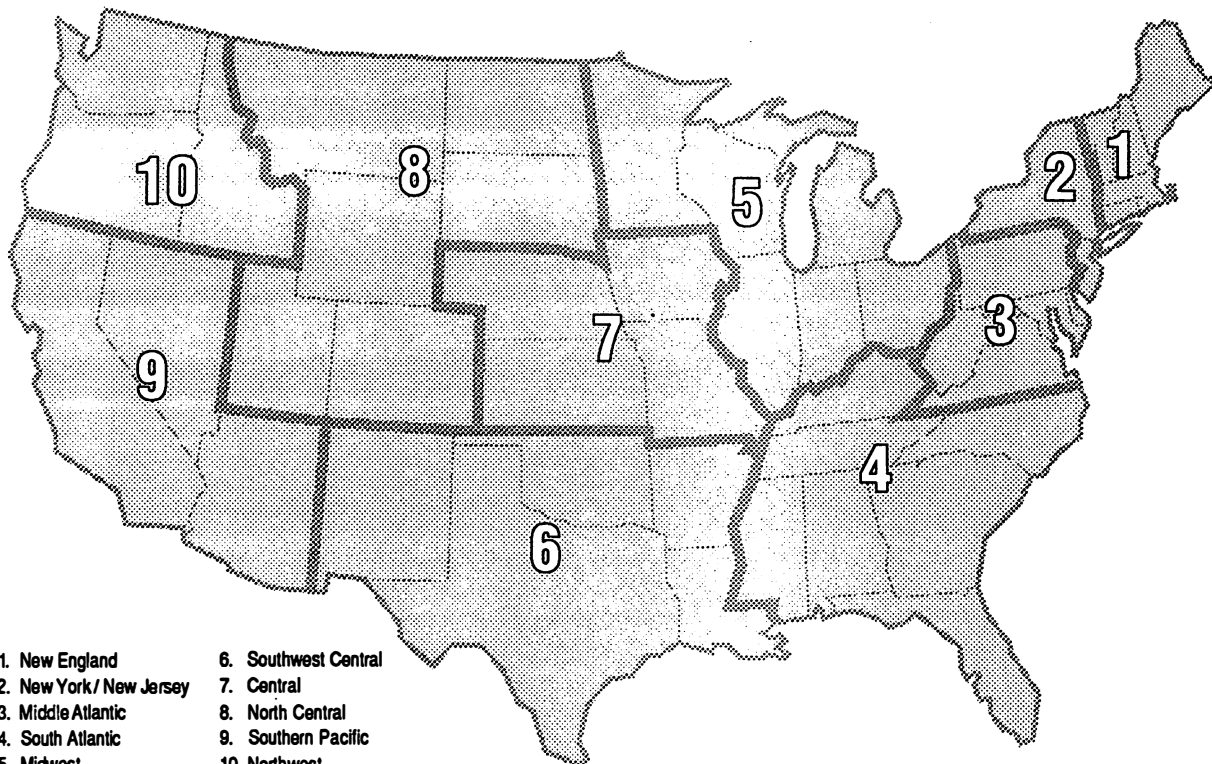
Summary Of Environmental Assumptions

- Acid rain scenario based on Title IV of CAAA of 1990:
 - Starts in 1995, Phase II in 2000
 - 12,000 MW scrubbing in 2000, increasing to 20,000 in 2005
 - Efficient market leads to marginal SO₂ control costs of \$450-500/ton in 2000 and \$550-600/ton in 2005
 - Gas cofiring market is 190-230 bcf/year
 - Industrials impacted by tightened SIPS
- Vehicle gas consumption under Clean Air Act based on positive outlook for CNG vehicle penetration:
 - By 2000, 50 Bcf
 - By 2005, 100 Bcf
 - By 2010, 140 Bcf

U.S. ENERGY DEMAND AND ECONOMIC ACTIVITY

Introduction To U.S. Energy Demand Trends

- NPC Demand and Distribution group modified energy demand trends in all end-use sectors by targeting specific energy intensity trends:
 - Residential energy use per building
 - Commercial energy use per square foot
 - Industrial energy use per unit of output
- The impact of these changes was to decrease energy demand growth below levels which models would have projected.
- Energy demand, energy intensity, and macro-economic inputs are itemized in the following section. Other demand-related assumptions also are itemized.



NOTE: Alaska and Hawaii Excluded

EOM Demand Regions of the United States

- Macro-economic inputs were prepared by DRI/McGraw Hill for NPC on a regional basis. However, the SIC mix of industrial production output was modified by NPC Demand & Distribution group from that projected by DRI, while total growth in output was retained as projected.

Comparison Of Key Economic And Energy Assumptions

NPC High And Low Reference Cases
(GROWTH RATES ARE PERCENT P.A., 1990-2010)

Scenario Assumption	Case 1: High Reference	Case 2: Low Reference
Economic Growth	Moderate	Slowed
GNP	2.4%	2.0%
Disposable Income	1.80%	1.49%
Industrial Production	2.70%	2.25%
Population Growth	0.64%	0.31%
Residential Housing Stock	1.01%	0.74%
Commercial Floor Space	1.40%	1.08%
General		
World Oil Price (\$1990 in 2010)	\$27.85 /bbl	\$20.00/ bbl
U.S. Energy Demand (2010)	Approx. 100 Quads	Approx. 88 Quads
Environmental Laws	Currently enacted	Currently enacted
Energy taxes (new)	None	None

Total U.S. Energy Demand

(QUADS)

		Case 1: High Ref.	Case 2: Low Ref.
	1990	2010	2010
Industrial			
Fuel & Power ¹	16.8	21.3	16.5
Raw materials	6.0	7.2	6.7
Subtotal	22.8	28.5	23.2
Residential	9.0	10.3	9.6
Commercial	6.5	8.2	7.7
Electric Losses	20.0	25.0	22.8
Transportation^{2,3}	22.1	28.1	24.4
Total	80.4	100.1	87.7

¹ Includes lease and plant gas use.

² Includes CNG vehicle demand and gas pipeline fuel.

³ Transportation sector energy projection prepared for NPC by DRI.

Comparison Of Energy Demand Trends By Sector

NPC High And Low Reference Cases
(GROWTH RATES ARE PERCENT P.A., 1990-2010)

	Case 1: High Reference	Case 2: Low Reference
RESIDENTIAL		
Housing Stock Growth	1.01%	0.74%
Energy Intensity ¹	-0.5%	-0.6%
Energy Demand ²	+0.5%	+0.1%
Electricity Demand	1.65%	1.08%
COMMERCIAL³		
Floor Space Growth	1.40%	1.08%
New Gas Technologies (cogen, cooling)	Modest penetration	No growth
Energy Intensity ¹	-0.4%	-0.4%
Energy Demand ²	+1.0%	+0.7%
Electricity Demand	1.45%	1.30%

¹ Energy use per unit (building, sq. ft. of floor space). Target intensity trend selected by NPC Demand and Distribution group.

² Energy demand growth rate on a weather normalized basis. Actual 1990-2010 growth rates will differ due to effect of weather patterns on 1990 energy demand.

³ Excludes natural gas vehicles, which are reported with commercial sector in standard model outputs.

Comparison Of Energy Demand Trends By Sector

NPC High And Low Reference Cases
(GROWTH RATES ARE PERCENT P.A., 1990-2010)
— CONT'D —

	Case 1: High Reference	Case 2: Low Reference	
INDUSTRIAL			
Production Growth	2.70%	2.25%	
SIC Mix of Production	1983-90 Trends	1983-90 Trends	
Energy Efficiency Gains	1983-90 Period	1973-80 Period	
Industrial Cogeneration	EEA Scenario for 1993 GRI Baseline Projection	Minor downward adjust- ment in growth to match slower steam demand growth (1995-2010)	
Industrial Energy Demand (Quads)			
	1990	2010	2010
Fuel & Power (ex L&P)	15.58	20.03	15.46
Raw Materials	5.97	7.21	6.69
Total (ex L&P)	21.59	27.24 (1.2%)	22.15 (0.1%)
+ L&P	1.27	1.25	1.08
Total Industrial	22.81	28.49 (1.1%)	23.23 (0.1%)
Purchased Electricity	3.21	4.54 (1.7%)	4.33 (1.5%)

Comparison Of Energy Demand Trends By Sector

NPC High And Low Reference Cases
(GROWTH RATES ARE PERCENT P.A., 1990-2010)
— CONT'D —

	Case 1: High Reference		Case 2: Low Reference
ELECTRIC UTILITY			
Purchased Electricity Growth	1.62%		1.30%
Energy-QUADS	1990	2010	2010
Inputs	29.4	37.7(1.2%)	35.5(0.9%)
Losses	20.0	25.0	22.8
Key Assumptions			
Repowering	Adds 21 GW to existing oil/gas capacity, mostly after 2000		Adds 15 GW to existing oil/gas capacity
Heat Rate Improvement	New Units improve 6% by 2010 over 1990 technology		Same
	Existing units improve 2-3% (on average) due to refurbishment		Same
Fuel Mix in New Units	New gas-fired generators assumed supplied at firm transport gas rates		Same
	Utility price expectations assume future gas prices will ramp to residual oil equivalent		Same

Lower-48 Natural Gas Consumption

(QUADS)

		Case 1: High Ref.	Case 2: Low Ref.
	1990	2010	2010
Residential	4.5	4.9	4.7
Commercial ¹	2.7	3.5	3.1
Industrial	7.0	8.9	6.1
Electric Utility	2.9	5.4	4.9
Total	17.1	22.7	18.8
+Lease/Plant	1.1	1.3	1.1
+PPL Fuel	0.6	0.9	0.7
+Exports/UAF	0.2	0.2	0.7
Total Disposition	19.0	25.0	21.3

¹ Includes 0.14 Quads for gas demand in natural gas vehicles in 2010.

Economic And Demographic Inputs

NPC HIGH REFERENCE CASE

Industrial Production Growth Rates

NPC High Reference Case (No. 3)

	FRB Index 77=1.00	FRB Index 87=1.00	Scenario Growth Rates (% p.a.)
1980	1.086	0.837	
1981	1.110	0.855	
1982	1.031	0.794	
1983	1.092	0.841	
1984	1.218	0.938	
1985	1.238	0.954	
1986	1.251	0.964	
1987	1.298	1.000	
1988	1.372	1.057	
1989	1.403	1.081	
1990	1.417	1.092	
1991	1.390	1.071	-1.9%
1992	1.418	1.092	2.0%
1993	1.488	1.146	4.9%
1994	1.535	1.182	3.1%
1995	1.583	1.220	3.2%
1996	1.630	1.256	2.9%
1997	1.677	1.292	2.9%
1998	1.740	1.341	3.8%
1999	1.794	1.382	3.1%
2000	1.850	1.425	3.1%
2001	1.912	1.473	3.4%
2002	1.972	1.519	3.1%
2003	2.038	1.570	3.3%
2004	2.101	1.619	3.1%
2005	2.156	1.661	2.6%
2006	2.212	1.704	2.6%
2007	2.268	1.747	2.5%
2008	2.318	1.786	2.2%
2009	2.365	1.822	2.0%
2010	2.413	1.859	2.0%
1990-2000			2.70%
2000-2010			2.69%
1990-2010			2.69%

Industrial Production By Federal Region

NPC High Reference Case

– Millions \$1977 –

FRB INDEX ('77) 109.2

1.0% Growth

1990	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,040	18,129	24,671	42,437	57,637	28,479	27,815	8,313	25,792	8,971	248,284	1.1%
Textiles	2,895	2,427	4,818	38,890	1,124	622	121	0	1,410	169	52,476	-1.2%
Paper	6,831	6,746	7,041	16,985	19,925	5,737	2,120	331	4,129	3,916	73,761	2.1%
Chemicals	6,392	25,819	20,115	35,609	34,218	24,607	7,267	1,564	11,560	3,479	170,631	1.5%
Refining	371	6,907	9,143	8,944	17,561	44,314	4,312	4,354	25,053	1,248	122,206	2.1%
Stone Etc.	1,613	3,832	5,334	8,878	8,753	4,569	2,468	1,441	4,909	1,056	42,852	-2.0%
Steel	1,468	2,075	15,234	6,059	26,405	2,112	1,181	1,158	2,024	700	58,416	0.4%
Aluminum	3,067	3,505	4,156	7,978	10,623	3,896	1,674	1,606	4,635	2,012	43,152	-2.7%
All Other	89,573	101,128	101,428	183,065	308,914	87,839	69,794	26,319	182,909	37,769	1,188,737	1.1%
Total	118,250	170,568	191,941	348,844	485,159	202,174	116,752	45,085	262,421	59,319	2,000,514	1.0%
Annual Growth	-1.7%	-0.1%	-0.1%	1.2%	0.3%	2.2%	1.6%	3.0%	2.7%	4.5%	1.0%	

Industrial Production By Federal Region

NPC High Reference Case

– Millions \$1977 –

FRB INDEX ('77): 121.3

3.6%: Growth

1995	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,222	18,380	28,416	47,288	63,053	31,971	31,250	9,269	28,726	9,892	274,468	2.8%
Textiles	3,080	2,346	5,008	41,204	1,218	725	143	0	1,529	187	55,440	1.8%
Paper	7,360	6,996	7,572	19,048	22,061	6,482	2,411	362	4,513	4,208	81,013	3.2%
Chemicals	7,524	29,346	22,495	39,755	39,650	29,776	8,187	1,807	13,362	4,048	195,951	4.2%
Refining	355	7,095	9,421	9,405	18,101	49,457	4,753	4,911	25,571	1,487	130,556	2.2%
Stone Etc.	1,557	3,836	5,426	9,261	9,516	4,923	2,621	1,522	5,184	1,088	44,936	2.6%
Steel	1,325	1,884	15,325	6,148	27,211	2,232	1,226	1,149	2,004	700	59,203	1.6%
Aluminum	3,072	3,540	4,747	8,959	12,305	4,198	1,926	1,683	4,753	2,096	47,281	3.2%
All Other	99,844	108,339	113,636	211,235	335,441	101,055	79,336	31,210	210,673	42,567	1,333,335	4.0%
Total	130,339	181,763	212,046	392,303	528,557	230,819	131,854	51,912	296,316	66,274	2,222,182	3.6%
Annual Growth	4.4%	2.9%	3.8%	3.5%	2.9%	3.6%	3.8%	4.5%	4.3%	3.8%	3.6%	

Industrial Production By Federal Region

NPC High Reference Case

– Millions \$1977 –

FRB INDEX ('77): 141.2

3.1% Growth

2000	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,957	20,208	33,694	54,614	71,654	36,673	35,989	10,634	32,926	11,339	314,688	2.8%
Textiles	3,302	2,385	5,453	45,447	1,328	783	159	0	1,699	201	60,757	1.8%
Paper	8,554	7,998	8,745	22,440	25,903	7,553	2,867	430	5,365	4,833	94,688	3.2%
Chemicals	10,156	36,297	27,691	48,774	48,429	36,388	9,993	2,193	16,217	4,858	240,996	4.2%
Refining	445	7,886	10,533	10,885	19,859	54,605	5,563	5,627	28,757	1,721	145,881	2.2%
Stone Etc.	1,748	4,231	6,100	10,648	10,879	5,674	2,994	1,740	5,923	1,254	51,190	2.6%
Steel	1,401	1,925	16,591	6,733	29,434	2,447	1,356	1,233	2,160	765	64,044	1.6%
Aluminum	3,513	3,888	5,696	10,715	14,678	4,764	2,292	1,937	5,390	2,390	55,262	3.2%
All Other	123,730	122,924	132,852	246,644	371,850	118,433	93,430	38,568	259,808	50,998	1,559,238	3.2%
Total	159,804	207,742	247,355	456,900	594,013	267,320	154,643	62,362	358,246	78,358	2,586,745	3.1%
Annual Growth	4.2%	2.7%	3.1%	3.1%	2.4%	3.0%	3.2%	• 3.7%	3.9%	3.4%	3.1%	

Industrial Production By Federal Region

NPC High Reference Case

– Millions \$1977 –

FRB INDEX ('77): 164.9

3.2% Growth

2005	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	7,763	22,513	38,131	63,685	81,999	42,292	40,856	12,272	38,169	13,123	360,803	2.8%
Textiles	3,540	2,528	5,993	49,963	1,447	860	187	0	1,848	218	66,584	1.8%
Paper	9,831	9,137	10,130	26,534	30,296	8,925	3,338	506	6,318	5,657	110,672	3.2%
Chemicals	12,919	44,378	33,991	60,672	59,333	44,536	12,281	2,655	19,632	5,998	296,395	4.2%
Refining	498	8,728	11,672	12,451	22,251	60,810	6,372	6,348	31,919	1,956	163,005	2.2%
Stone Etc.	1,941	4,690	6,896	12,187	12,379	6,525	3,394	2,007	6,840	1,456	58,316	2.6%
Steel	1,512	2,056	17,968	7,403	31,674	2,664	1,470	1,343	2,351	839	69,281	1.6%
Aluminum	3,851	4,244	7,523	12,216	18,072	5,320	2,565	2,185	5,964	2,650	64,591	3.2%
All Other	148,525	141,412	156,401	288,404	429,935	140,082	109,137	46,125	311,544	59,710	1,831,276	3.3%
Total	190,378	239,686	288,705	533,515	687,387	312,015	179,601	73,441	424,585	91,607	3,020,922	3.2%
Annual Growth	3.6%	2.9%	3.1%	3.1%	3.0%	3.1%	3.0%	3.3%	3.5%	3.2%	3.2%	

Industrial Production By Federal Region

NPC High Reference Case

– Millions \$1977 –

FRB INDEX ('77): 186.2

2.5%: Growth

2010	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	8,692	25,173	43,232	74,056	93,866	48,728	46,447	14,148	44,169	15,165	413,675	2.8%
Textiles	3,799	2,681	6,586	54,916	1,578	946	218	0	2,011	236	72,970	1.8%
Paper	11,328	10,474	11,751	31,311	35,429	10,526	3,890	596	7,430	6,619	129,354	3.2%
Chemicals	16,312	54,319	41,740	75,299	72,746	54,559	15,096	3,223	23,835	7,401	364,530	4.2%
Refining	557	9,662	12,937	14,224	24,928	67,728	7,287	7,158	35,436	2,222	182,139	2.2%
Stone Etc.	2,159	5,210	7,801	13,942	14,087	7,496	3,850	2,312	7,888	1,688	66,433	2.6%
Steel	1,632	2,194	19,462	8,149	34,068	2,902	1,595	1,463	2,560	921	74,946	1.6%
Aluminum	4,277	4,697	9,553	14,008	21,929	6,000	2,898	2,485	6,676	2,972	75,495	3.2%
All Other	167,247	154,599	173,795	318,970	471,724	156,166	120,617	51,809	350,567	66,099	2,031,592	2.1%
Total	216,003	269,007	326,856	604,876	770,355	355,051	201,897	83,194	480,570	103,322	3,411,132	2.5%
Annual Growth	2.6%	2.3%	2.5%	2.5%	2.3%	2.6%	2.4%	2.5%	2.5%	2.4%	2.5%	

Residential Sector Housing Stock By Region

NPC High Reference Case

– Thousands Of Units –

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN. GROWTH RATE (%)
1990	5,648	10,481	9,747	18,739	18,658	11,398	7,278	3,148	12,978	3,528	101,603	2.0%
1991	5,698	10,545	9,854	19,018	18,834	11,494	7,334	3,180	13,185	3,604	102,746	1.1%
1992	5,740	10,594	9,943	19,261	18,987	11,591	7,383	3,216	13,345	3,672	103,732	1.0%
1993	5,783	10,646	10,030	19,529	19,147	11,708	7,437	3,253	13,516	3,741	104,790	1.0%
1994	5,828	10,704	10,116	19,809	19,309	11,843	7,494	3,291	13,698	3,809	105,901	1.1%
1995	5,875	10,766	10,204	20,104	19,477	12,000	7,554	3,331	13,899	3,879	107,089	1.1%
1996	5,924	10,830	10,299	20,416	19,651	12,167	7,616	3,372	14,120	3,952	108,347	1.2%
1997	5,974	10,895	10,397	20,731	19,823	12,337	7,676	3,412	14,352	4,025	109,622	1.2%
1998	6,025	10,960	10,494	21,045	19,988	12,510	7,735	3,454	14,590	4,098	110,899	1.2%
1999	6,076	11,025	10,590	21,353	20,144	12,683	7,789	3,496	14,829	4,169	112,154	1.1%
2000	6,127	11,088	10,684	21,652	20,289	12,856	7,839	3,538	15,064	4,237	113,374	1.1%
2001	6,178	11,151	10,779	21,948	20,427	13,027	7,886	3,582	15,301	4,303	114,582	0.9%
2002	6,230	11,214	10,876	22,249	20,566	13,199	7,933	3,627	15,539	4,369	115,803	0.9%
2003	6,281	11,276	10,970	22,539	20,698	13,368	7,977	3,671	15,775	4,433	116,989	0.9%
2004	6,329	11,335	11,063	22,814	20,822	13,530	8,015	3,712	16,002	4,494	118,117	0.9%
2005	6,377	11,391	11,150	23,076	20,937	13,687	8,050	3,752	16,221	4,554	119,195	0.9%
2006	6,421	11,443	11,231	23,322	21,043	13,836	8,081	3,790	16,431	4,611	120,208	0.9%
2007	6,464	11,492	11,308	23,555	21,142	13,980	8,108	3,827	16,636	4,665	121,175	0.9%
2008	6,506	11,541	11,383	23,788	21,240	14,123	8,134	3,864	16,841	4,719	122,139	0.9%
2009	6,551	11,592	11,460	24,030	21,342	14,269	8,163	3,903	17,051	4,775	123,136	0.9%
2010	6,597	11,645	11,541	24,282	21,447	14,418	8,193	3,943	17,263	4,831	124,160	0.9%
1990-2000	0.89%	0.49%	0.97%	1.57%	0.76%	1.08%	0.64%	1.23%	1.59%	1.90%	1.10%	
2000-2010	0.82%	0.51%	0.84%	1.23%	0.54%	1.09%	0.47%	0.98%	1.22%	1.27%	0.91%	
1990-2010	0.78%	0.53%	0.85%	1.30%	0.70%	1.18%	0.59%	1.13%	1.44%	1.58%	1.01%	

Commercial Sector Square Footage By Region

NPC High Reference Case – Million Square Feet

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN GROWTH RATE (%)
1990	2,430	4,363	4,680	8,080	8,915	5,563	2,300	1,578	6,221	1,672	45,802	2.1%
1991	2,463	4,399	4,769	8,276	9,059	5,617	2,325	1,596	6,426	1,701	46,631	1.8%
1992	2,449	4,371	4,779	8,290	9,069	5,609	2,322	1,596	6,527	1,709	46,721	0.2%
1993	2,428	4,349	4,789	8,302	9,100	5,626	2,326	1,602	6,625	1,722	46,869	0.3%
1994	2,405	4,333	4,806	8,359	9,162	5,666	2,339	1,614	6,722	1,740	47,146	0.6%
1995	2,387	4,317	4,824	8,468	9,237	5,715	2,354	1,625	6,809	1,758	47,494	0.7%
1996	2,381	4,305	4,850	8,624	9,323	5,779	2,371	1,638	6,894	1,775	47,940	0.9%
1997	2,391	4,300	4,884	8,798	9,411	5,854	2,389	1,652	6,981	1,791	48,451	1.1%
1998	2,415	4,308	4,928	8,967	9,504	5,942	2,410	1,669	7,075	1,807	49,025	1.2%
1999	2,451	4,332	4,988	9,131	9,615	6,046	2,435	1,689	7,190	1,828	49,705	1.4%
2000	2,494	4,373	5,065	9,293	9,748	6,165	2,468	1,715	7,326	1,853	50,500	1.6%
2001	2,538	4,427	5,154	9,456	9,902	6,298	2,506	1,745	7,482	1,884	51,392	1.8%
2002	2,580	4,492	5,249	9,622	10,073	6,442	2,549	1,778	7,649	1,918	52,352	1.9%
2003	2,616	4,563	5,348	9,791	10,257	6,594	2,596	1,815	7,822	1,957	53,359	1.9%
2004	2,648	4,638	5,448	9,964	10,448	6,752	2,645	1,854	7,996	1,998	54,391	1.9%
2005	2,675	4,713	5,544	10,135	10,638	6,910	2,693	1,893	8,163	2,040	55,404	1.9%
2006	2,703	4,789	5,640	10,310	10,828	7,072	2,741	1,934	8,328	2,084	56,429	1.9%
2007	2,731	4,867	5,736	10,491	11,019	7,239	2,789	1,976	8,495	2,130	57,473	1.9%
2008	2,758	4,943	5,830	10,670	11,203	7,405	2,836	2,017	8,660	2,176	58,498	1.8%
2009	2,785	5,017	5,923	10,846	11,380	7,571	2,880	2,058	8,823	2,222	59,505	1.7%
2010	2,812	5,090	6,015	11,020	11,552	7,737	2,923	2,099	8,986	2,268	60,502	1.7%
1990-2000	0.38%	0.45%	1.11%	1.60%	1.09%	1.30%	1.00%	1.34%	2.06%	1.54%	0.98%	
2000-2010	0.45%	0.31%	0.83%	1.22%	0.70%	1.22%	0.65%	0.98%	1.23%	0.92%	1.82%	
1990-2010	0.73%	0.77%	1.26%	1.56%	1.30%	1.66%	1.21%	1.44%	1.86%	1.54%	1.40%	

Disposable Income By Region

NPC High Reference Case – Billions Of 1982 Dollars

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN GROWTH RATE (%)
1990	178.7	352.5	291.4	469.4	523.5	279.6	191.6	78.2	424.6	96.7	2,886	-0.5%
1991	174.4	347.0	288.3	469.7	519.2	282.7	189.2	77.8	419.4	96.8	2,865	-0.8%
1992	174.9	349.3	290.1	479.4	529.3	289.0	193.2	79.1	423.4	99.3	2,907	1.5%
1993	179.1	355.3	296.5	495.2	544.5	298.9	199.1	81.7	436.6	102.9	2,990	2.8%
1994	184.8	363.6	303.5	511.9	560.9	309.4	205.2	84.6	452.3	106.4	3,082	3.1%
1995	188.9	372.1	309.9	526.5	573.4	318.1	210.1	86.9	465.6	109.4	3,161	2.5%
1996	192.3	378.9	315.5	539.1	582.9	325.2	213.0	88.6	476.0	111.6	3,223	2.0%
1997	195.7	384.2	320.7	549.9	590.9	331.8	215.6	90.0	485.5	113.5	3,278	1.7%
1998	199.6	390.6	325.8	562.2	600.9	338.9	219.8	91.8	497.4	116.0	3,343	2.0%
1999	203.8	396.8	331.8	574.7	611.2	346.3	224.2	93.7	510.1	118.6	3,411	2.0%
2000	207.2	402.2	337.3	586.2	620.2	352.8	227.9	95.5	521.5	120.8	3,472	1.8%
2001	210.4	407.8	342.6	597.8	629.1	358.9	231.3	97.2	532.6	123.0	3,531	1.7%
2002	213.7	412.7	348.5	608.9	637.5	364.7	234.4	98.9	543.2	125.3	3,588	1.6%
2003	217.5	418.1	354.9	621.3	647.5	371.5	238.1	100.7	554.6	127.6	3,652	1.8%
2004	221.6	424.0	362.5	635.5	659.4	379.5	242.4	102.8	567.6	130.4	3,726	2.0%
2005	225.4	429.6	370.5	649.8	670.4	387.7	246.4	104.9	580.8	133.0	3,798	2.0%
2006	228.9	435.1	377.4	663.3	679.8	395.3	249.9	106.8	593.0	135.3	3,865	1.7%
2007	232.4	440.4	384.0	676.7	689.1	402.6	253.5	108.7	605.0	137.6	3,930	1.7%
2008	235.8	446.2	390.4	690.0	698.0	409.8	257.0	110.6	617.0	140.0	3,995	1.6%
2009	239.2	451.8	396.8	702.9	705.9	416.8	260.2	112.4	628.4	142.3	4,057	1.6%
2010	242.7	457.6	403.4	716.0	714.0	424.1	263.4	114.2	639.9	144.6	4,120	1.6%
1990-2000	1.49%	1.33%	1.47%	2.25%	1.71%	2.35%	1.75%	2.02%	2.08%	2.25%	1.86%	
2000-2010	1.59%	1.30%	1.80%	2.02%	1.42%	1.86%	1.46%	1.80%	2.07%	1.81%	1.73%	
1990-2010	1.54%	1.31%	1.64%	2.13%	1.56%	2.10%	1.60%	1.91%	2.07%	2.03%	1.80%	

Resident Population By Region

NPC High Reference Case
– Thousands of Persons –

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN. GROWTH RATE (%)
1990	13,204	25,749	24,197	46,760	46,518	28,359	18,382	7,633	34,887	8,797	254,486	0.4%
1991	13,198	25,819	24,390	47,464	46,888	28,757	18,509	7,727	35,567	9,007	257,326	1.1%
1992	13,193	25,829	24,519	48,055	47,204	29,160	18,639	7,809	36,088	9,169	259,665	0.9%
1993	13,225	25,826	24,607	48,590	47,467	29,541	18,756	7,881	36,473	9,289	261,655	0.8%
1994	13,289	25,879	24,716	49,115	47,739	29,872	18,871	7,950	36,841	9,381	263,653	0.8%
1995	13,363	25,968	24,842	49,613	47,951	30,165	18,965	8,006	37,215	9,461	265,549	0.7%
1996	13,446	26,094	24,977	50,086	48,111	30,482	19,041	8,061	37,629	9,537	267,464	0.7%
1997	13,539	26,219	25,121	50,530	48,258	30,778	19,117	8,112	38,043	9,592	269,309	0.7%
1998	13,631	26,328	25,264	50,972	48,424	31,038	19,199	8,162	38,440	9,640	271,098	0.7%
1999	13,714	26,418	25,405	51,415	48,603	31,282	19,286	8,212	38,819	9,691	272,845	0.6%
2000	13,783	26,490	25,548	51,850	48,787	31,520	19,379	8,265	39,186	9,745	274,553	0.6%
2001	13,839	26,553	25,688	52,273	49,040	31,720	19,527	8,322	39,510	9,793	276,265	0.6%
2002	13,913	26,641	25,837	52,723	49,197	31,925	19,586	8,375	39,831	9,848	277,876	0.6%
2003	13,977	26,719	25,969	53,146	49,323	32,122	19,628	8,425	40,127	9,900	279,336	0.5%
2004	14,031	26,780	26,109	53,565	49,445	32,332	19,664	8,475	40,434	9,950	280,785	0.5%
2005	14,071	26,819	26,266	53,990	49,556	32,545	19,691	8,527	40,761	9,998	282,224	0.5%
2006	14,112	26,850	26,423	54,423	49,657	32,754	19,714	8,579	41,092	10,047	283,651	0.5%
2007	14,160	26,892	26,570	54,864	49,745	32,956	19,737	8,630	41,413	10,095	285,062	0.5%
2008	14,213	26,944	26,710	55,306	49,822	33,153	19,758	8,678	41,730	10,144	286,458	0.5%
2009	14,266	27,007	26,844	55,742	49,891	33,342	19,779	8,725	42,044	10,195	287,835	0.5%
2010	14,320	27,076	26,978	56,175	49,948	33,529	19,797	8,772	42,354	10,249	289,198	0.5%
1990-2000	0.43%	0.28%	0.54%	1.04%	0.48%	1.06%	0.53%	0.80%	1.17%	1.03%	0.76%	
2000-2010	0.38%	0.22%	0.55%	0.80%	0.24%	0.62%	0.21%	0.60%	0.78%	0.51%	0.52%	

Economic And Demographic Inputs

NPC LOW REFERENCE CASE

Industrial Production Growth Rates

NPC Low Reference Case (No. 3)

	FRB Index 77=1.00	FRB Index 87=1.00	Scenario Growth Rates (% p.a.)	
1980	1.086	0.837		
1981	1.110	0.855		
1982	1.031	0.794		
1983	1.092	0.841		
1984	1.218	0.938		
1985	1.238	0.954		
1986	1.251	0.964		
1987	1.298	1.000		
1988	1.372	1.057		NPC High
1989	1.403	1.081		Reference
1990	1.417	1.092		Case
1991	1.390	1.071	-1.9%	-1.9%
1992	1.418	1.092	2.0%	2.0%
1993	1.475	1.137	4.0%	4.9%
1994	1.507	1.161	2.2%	3.1%
1995	1.546	1.191	2.6%	3.2%
1996	1.586	1.222	2.6%	2.9%
1997	1.628	1.254	2.6%	2.9%
1998	1.684	1.297	3.5%	3.8%
1999	1.732	1.335	2.9%	3.1%
2000	1.780	1.371	2.7%	3.1%
2001	1.830	1.410	2.8%	3.4%
2002	1.882	1.450	2.9%	3.1%
2003	1.941	1.495	3.1%	3.3%
2004	1.998	1.540	3.0%	3.1%
2005	2.043	1.574	2.2%	2.6%
2006	2.073	1.597	1.5%	2.6%
2007	2.106	1.623	1.6%	2.5%
2008	2.141	1.649	1.6%	2.2%
2009	2.176	1.676	1.6%	2.0%
2010	2.211	1.704	1.6%	2.0%
1990-2000			2.30%	2.70%
2000-2010			2.19%	2.69%
1990-2010			2.25%	2.69%

Industrial Production By Federal Region

NPC Low Reference Case

– Millions \$1977 –

FRB INDEX ('77) : 109.2

1.0%: Growth

1990	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,040	18,129	24,671	42,437	57,637	28,479	27,815	8,313	25,792	8,971	248,284	1.1%
Textiles	2,895	2,427	4,818	38,890	1,124	622	121	0	1,410	169	52,476	-1.2%
Paper	6,831	6,746	7,041	16,985	19,925	5,737	2,120	331	4,129	3,916	73,761	2.1%
Chemicals	6,392	25,819	20,115	35,609	34,218	24,607	7,267	1,564	11,560	3,479	170,631	1.5%
Refining	371	6,907	9,143	8,944	17,561	44,314	4,312	4,354	25,053	1,248	122,206	2.1%
Stone Etc.	1,613	3,832	5,334	8,878	8,753	4,569	2,468	1,441	4,909	1,056	42,852	-2.0%
Steel	1,468	2,075	15,234	6,059	26,405	2,112	1,181	1,158	2,024	700	58,416	0.4%
Aluminum	3,067	3,505	4,156	7,978	10,623	3,896	1,674	1,606	4,635	2,012	43,152	-2.7%
All Other	89,573	101,128	101,428	183,065	308,914	87,839	69,794	26,319	182,909	37,769	1,188,737	1.1%
Total	118,250	170,568	191,941	348,844	485,159	202,174	116,752	45,085	262,421	59,319	2,000,514	1.0%
Annual Growth	-1.7%	-0.1%	-0.1%	1.2%	0.3%	2.2%	1.6%	3.0%	2.7%	4.5%	1.0%	

Industrial Production By Federal Region

NPC Low Reference Case

– Millions \$1977 –

FRB INDEX ('77) : 119.1

2.9%: Growth

1995	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,134	18,118	28,011	46,615	62,155	31,516	30,806	9,137	28,317	9,752	270,561	2.3%
Textiles	3,051	2,323	4,960	40,809	1,207	718	141	0	1,515	185	54,908	1.5%
Paper	7,241	6,883	7,449	18,740	21,704	6,377	2,372	356	4,440	4,139	79,701	2.6%
Chemicals	7,364	28,720	22,015	38,906	38,804	29,141	8,012	1,769	13,077	3,962	191,770	3.5%
Refining	351	7,012	9,311	9,296	17,892	48,883	4,698	4,854	25,275	1,470	129,043	1.8%
Stone Etc.	1,536	3,784	5,352	9,135	9,387	4,857	2,586	1,501	5,114	1,073	44,326	2.2%
Steel	1,314	1,868	15,199	6,097	26,987	2,214	1,216	1,139	1,987	694	58,715	1.3%
Aluminum	3,022	3,483	4,671	8,814	12,105	4,130	1,895	1,656	4,676	2,062	46,515	2.6%
All Other	97,822	106,146	111,335	206,958	328,649	99,009	77,730	30,578	206,408	41,705	1,306,341	3.3%
Total	127,834	178,339	208,304	385,371	518,890	226,844	129,456	50,989	290,809	65,043	2,181,879	2.9%
Annual Growth	3.7%	2.2%	3.2%	2.9%	2.3%	3.0%	3.2%	3.9%	3.7%	3.1%	2.9%	

Industrial Production By Federal Region

NPC Low Reference Case

– Millions \$1977 –

FRB INDEX ('77): 137.1

2.9%: Growth

2000	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	6,696	19,450	32,430	52,566	68,966	35,297	34,639	10,235	31,691	10,914	302,885	2.3%
Textiles	3,219	2,325	5,315	44,294	1,294	763	155	0	1,656	196	59,216	1.5%
Paper	8,189	7,657	8,372	21,484	24,800	7,231	2,745	411	5,137	4,627	90,654	2.6%
Chemicals	9,588	34,268	26,143	46,048	45,722	34,354	9,434	2,071	15,311	4,587	227,527	3.5%
Refining	431	7,645	10,210	10,552	19,251	52,933	5,393	5,455	27,877	1,668	141,415	1.8%
Stone Etc.	1,685	4,079	5,882	10,267	10,490	5,471	2,887	1,677	5,711	1,209	49,358	2.2%
Steel	1,370	1,883	16,228	6,586	28,791	2,394	1,326	1,206	2,113	748	62,645	1.3%
Aluminum	3,363	3,723	5,454	10,259	14,053	4,561	2,194	1,854	5,160	2,288	52,908	2.6%
All Other	121,015	120,227	129,937	241,233	363,691	115,835	91,380	37,722	254,108	49,879	1,525,027	3.1%
Total	155,556	201,256	239,972	443,287	577,057	258,840	150,154	60,632	348,763	76,115	2,511,634	2.9%
Annual Growth	4.0%	2.4%	2.9%	2.8%	2.1%	2.7%	3.0%	3.5%	3.7%	3.2%	2.9%	

Industrial Production By Federal Region

NPC Low Reference Case

– Millions \$1977 –

FRB INDEX ('77): 157.4

2.8%: Growth

2005	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	7,295	21,157	35,834	59,849	77,060	39,744	38,395	11,533	35,870	12,332	339,070	2.3%
Textiles	3,396	2,424	5,748	47,919	1,388	825	179	0	1,772	209	63,861	1.5%
Paper	9,159	8,513	9,438	24,722	28,226	8,315	3,110	472	5,886	5,270	103,112	2.6%
Chemicals	11,766	40,419	30,958	55,259	54,039	40,562	11,186	2,418	17,880	5,463	269,950	3.5%
Refining	473	8,298	11,097	11,838	21,155	57,814	6,058	6,035	30,346	1,860	154,973	1.8%
Stone Etc.	1,829	4,420	6,500	11,486	11,667	6,150	3,199	1,891	6,447	1,373	54,962	2.2%
Steel	1,459	1,983	17,335	7,142	30,558	2,570	1,419	1,296	2,268	809	66,839	1.3%
Aluminum	3,588	3,954	7,009	11,382	16,838	4,957	2,390	2,036	5,557	2,469	60,179	2.6%
All Other	143,602	136,725	151,217	278,845	415,685	135,439	105,520	44,596	301,218	57,731	1,770,578	3.0%
Total	182,566	227,894	275,136	508,441	656,616	296,377	171,455	70,277	407,245	87,517	2,883,524	2.8%
Annual Growth	3.3%	2.5%	2.8%	2.8%	2.6%	2.7%	2.7%	3.0%	3.1%	2.8%	2.8%	

Industrial Production By Federal Region

NPC Low Reference Case

– Millions \$1977 –

FRB INDEX ('77): 170.4

1.6%: Growth

2010	Federal Demand Regions										GROWTH	
	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	L-48 US	% P.A.
Food	7,975	23,098	39,669	67,952	86,129	44,711	42,618	12,982	40,529	13,915	379,579	2.3%
Textiles	3,585	2,530	6,216	51,831	1,490	893	206	0	1,898	222	68,870	1.5%
Paper	10,271	9,497	10,655	28,389	32,123	9,544	3,527	540	6,736	6,002	117,283	2.6%
Chemicals	14,332	47,726	36,673	66,159	63,916	47,936	13,264	2,832	20,942	6,502	320,283	3.5%
Refining	519	9,009	12,063	13,263	23,244	63,152	6,794	6,675	33,042	2,072	169,831	1.8%
Stone Etc.	1,989	4,799	7,187	12,844	12,978	6,906	3,546	2,130	7,267	1,555	61,202	2.2%
Steel	1,553	2,087	18,518	7,754	32,417	2,761	1,518	1,392	2,436	876	71,314	1.3%
Aluminum	3,878	4,258	8,662	12,701	19,882	5,440	2,628	2,254	6,053	2,695	68,450	2.6%
All Other	153,522	141,911	159,532	292,793	433,012	143,350	110,719	47,557	321,797	60,675	1,864,868	1.0%
Total	197,625	244,916	299,174	553,688	705,191	324,694	184,819	76,361	440,699	94,514	3,121,681	1.6%
Annual Growth	1.6%	1.5%	1.7%	1.7%	1.4%	1.8%	1.5%	1.7%	1.6%	1.6%	1.6%	

Residential Sector Housing Stock By Region

NPC Low Reference Case

– Thousands of Units –

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN GROWTH RATE (%)
1990	5,648	10,481	9,747	18,739	18,658	11,398	7,278	3,148	12,978	3,528	101,603	2.0%
1991	5,698	10,545	9,854	19,018	18,834	11,494	7,334	3,180	13,185	3,604	102,746	1.1%
1992	5,740	10,593	9,941	19,258	18,985	11,590	7,382	3,215	13,343	3,671	103,718	0.9%
1993	5,779	10,641	10,018	19,496	19,126	11,696	7,428	3,249	13,497	3,735	104,665	0.9%
1994	5,816	10,686	10,079	19,707	19,246	11,803	7,466	3,277	13,637	3,790	105,507	0.8%
1995	5,851	10,731	10,133	19,909	19,357	11,916	7,501	3,303	13,780	3,843	106,324	0.8%
1996	5,888	10,777	10,193	20,124	19,473	12,036	7,538	3,329	13,938	3,900	107,196	0.8%
1997	5,924	10,824	10,256	20,342	19,589	12,159	7,575	3,356	14,106	3,957	108,088	0.8%
1998	5,961	10,872	10,319	20,561	19,699	12,285	7,611	3,383	14,279	4,014	108,984	0.8%
1999	5,997	10,919	10,381	20,773	19,802	12,411	7,643	3,412	14,452	4,069	109,859	0.8%
2000	6,032	10,964	10,442	20,978	19,895	12,537	7,672	3,440	14,621	4,122	110,703	0.8%
2001	6,067	11,009	10,503	21,180	19,983	12,664	7,699	3,470	14,791	4,173	111,539	0.6%
2002	6,103	11,052	10,566	21,386	20,069	12,795	7,725	3,501	14,963	4,224	112,385	0.6%
2003	6,136	11,094	10,626	21,583	20,149	12,924	7,747	3,531	15,132	4,273	113,196	0.6%
2004	6,168	11,131	10,684	21,765	20,220	13,049	7,764	3,559	15,291	4,321	113,953	0.6%
2005	6,198	11,166	10,738	21,935	20,281	13,170	7,777	3,585	15,443	4,366	114,660	0.6%
2006	6,225	11,197	10,786	22,090	20,332	13,286	7,785	3,609	15,585	4,411	115,306	0.6%
2007	6,251	11,225	10,829	22,235	20,376	13,397	7,790	3,631	15,720	4,453	115,906	0.6%
2008	6,276	11,252	10,871	22,380	20,419	13,509	7,793	3,656	15,856	4,495	116,506	0.6%
2009	6,303	11,280	10,915	22,535	20,465	13,625	7,797	3,681	15,997	4,539	117,137	0.6%
2010	6,330	11,309	10,963	22,702	20,514	13,746	7,802	3,707	16,143	4,584	117,799	0.6%
1990-2000	0.89%	0.49%	0.97%	1.57%	0.76%	1.08%	0.64%	1.23%	1.59%	1.90%	0.86%	
2000-2010	0.82%	0.51%	0.84%	1.23%	0.54%	1.09%	0.47%	0.98%	1.22%	1.27%	0.62%	
1990-2010	0.57%	0.38%	0.59%	0.96%	0.48%	0.94%	0.35%	0.82%	1.10%	1.32%	0.74%	

Commercial Sector Square Footage By Region

NPC Low Reference Case – Million Square Feet

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN GROWTH RATE (%)
1990	2,430	4,363	4,680	8,080	8,915	5,563	2,300	1,578	6,221	1,672	45,802	2.1%
1991	2,463	4,399	4,769	8,276	9,059	5,617	2,325	1,596	6,426	1,701	46,631	1.8%
1992	2,449	4,371	4,778	8,289	9,068	5,609	2,322	1,596	6,526	1,709	46,717	0.2%
1993	2,427	4,349	4,787	8,292	9,094	5,624	2,325	1,602	6,621	1,721	46,842	0.3%
1994	2,403	4,331	4,797	8,327	9,141	5,660	2,334	1,612	6,710	1,736	47,051	0.4%
1995	2,381	4,310	4,804	8,396	9,190	5,702	2,344	1,621	6,780	1,750	47,278	0.5%
1996	2,369	4,292	4,813	8,499	9,239	5,750	2,353	1,630	6,839	1,761	47,545	0.6%
1997	2,370	4,279	4,825	8,615	9,284	5,805	2,362	1,639	6,892	1,771	47,842	0.6%
1998	2,384	4,276	4,846	8,731	9,330	5,868	2,372	1,649	6,949	1,782	48,187	0.7%
1999	2,411	4,288	4,882	8,850	9,392	5,943	2,386	1,662	7,024	1,795	48,633	0.9%
2000	2,444	4,316	4,934	8,976	9,478	6,032	2,407	1,680	7,122	1,814	49,203	1.2%
2001	2,480	4,358	4,999	9,105	9,583	6,133	2,434	1,702	7,238	1,837	49,869	1.4%
2002	2,513	4,409	5,072	9,234	9,704	6,245	2,466	1,728	7,366	1,864	50,601	1.5%
2003	2,541	4,466	5,147	9,364	9,839	6,363	2,501	1,757	7,499	1,895	51,372	1.5%
2004	2,564	4,527	5,225	9,494	9,983	6,487	2,538	1,787	7,633	1,929	52,167	1.5%
2005	2,583	4,588	5,298	9,622	10,126	6,611	2,575	1,818	7,762	1,964	52,947	1.5%
2006	2,601	4,651	5,372	9,752	10,270	6,740	2,612	1,851	7,890	2,001	53,740	1.5%
2007	2,620	4,714	5,445	9,879	10,411	6,874	2,648	1,884	8,017	2,039	54,531	1.5%
2008	2,637	4,776	5,514	10,000	10,542	7,006	2,681	1,917	8,141	2,076	55,290	1.4%
2009	2,654	4,835	5,580	10,117	10,664	7,137	2,712	1,949	8,260	2,113	56,021	1.3%
2010	2,670	4,893	5,646	10,235	10,781	7,266	2,742	1,981	8,378	2,151	56,743	1.3%
1990-2000	0.38%	0.45%	1.11%	1.60%	1.09%	1.30%	1.00%	1.34%	2.06%	1.54%	0.72%	
2000-2010	0.45%	0.31%	0.83%	1.22%	0.70%	1.22%	0.65%	0.98%	1.23%	0.92%	1.44%	
1990-2010	0.47%	0.57%	0.94%	1.19%	0.95%	1.34%	0.88%	1.14%	1.50%	1.27%	1.08%	

Disposable Income By Region

NPC Low Reference Case – Billions Of 1982 Dollars

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN GROWTH RATE (%)
1990	178.7	352.5	291.4	469.4	523.5	279.6	191.6	78.2	424.6	96.7	2,886	-0.5%
1991	174.4	347.0	288.3	469.7	519.2	282.7	189.2	77.8	419.4	96.8	2,865	-0.8%
1992	174.6	348.6	289.5	478.3	528.0	288.5	192.8	78.9	422.3	99.0	2,900	1.2%
1993	178.2	353.3	294.7	491.8	540.4	297.1	197.7	81.1	433.3	101.9	2,970	2.4%
1994	183.3	360.4	300.6	506.4	554.1	306.4	202.9	83.5	446.9	104.9	3,049	2.7%
1995	186.8	368.0	306.1	519.5	564.8	314.1	207.2	85.5	458.4	107.4	3,118	2.2%
1996	189.7	373.8	310.9	530.6	572.6	319.9	209.3	86.9	466.8	109.2	3,170	1.7%
1997	192.4	377.9	315.1	540.0	578.7	325.3	211.0	87.9	474.4	110.7	3,213	1.4%
1998	195.6	382.9	319.2	550.4	586.3	331.1	214.1	89.3	484.0	112.8	3,266	1.6%
1999	199.1	388.0	324.1	561.3	594.5	337.2	217.6	90.9	494.4	115.0	3,322	1.7%
2000	201.8	392.0	328.5	571.1	601.4	342.4	220.4	92.3	503.6	116.7	3,370	1.4%
2001	204.1	395.9	332.5	580.3	607.6	347.0	222.6	93.5	511.9	118.3	3,414	1.3%
2002	206.9	399.8	337.6	590.2	614.7	352.0	225.1	94.8	520.9	120.3	3,462	1.4%
2003	210.2	404.5	343.4	602.0	623.7	358.2	228.5	96.5	531.2	122.5	3,521	1.7%
2004	213.9	409.7	350.6	615.9	634.9	365.9	232.5	98.5	543.2	125.2	3,590	2.0%
2005	217.3	414.4	357.8	629.2	644.3	373.5	236.0	100.4	554.9	127.6	3,655	1.8%
2006	219.5	417.5	362.6	638.8	648.9	379.1	237.7	101.5	563.2	128.8	3,698	1.2%
2007	221.7	420.8	367.3	648.4	654.2	384.3	239.6	102.7	571.3	130.2	3,741	1.2%
2008	224.1	424.7	371.9	658.7	660.0	389.6	242.0	104.1	580.1	132.0	3,787	1.2%
2009	226.4	428.4	376.7	668.9	665.1	395.0	244.1	105.4	588.7	133.8	3,833	1.2%
2010	228.8	432.1	381.5	679.0	670.0	400.5	246.1	106.7	597.1	135.6	3,877	1.2%
1990-2000	1.22%	1.07%	1.21%	1.98%	1.40%	2.05%	1.41%	1.67%	1.72%	1.90%	1.56%	
2000-2010	1.26%	0.98%	1.51%	1.75%	1.09%	1.58%	1.11%	1.46%	1.72%	1.51%	1.41%	
1990-2010	1.24%	1.02%	1.36%	1.86%	1.24%	1.81%	1.26%	1.56%	1.72%	1.70%	1.49%	

Resident Population By Region

NPC Low Reference Case
– Thousands of Persons –

	NE	NY/NJ	MA	SA	MW	SWC	CEN	MTN	PAC	NW	LO48	ANN. GROWTH RATE (%)
1990	13,204	25,749	24,197	46,760	46,518	28,359	18,382	7,633	34,887	8,797	254,486	0.4%
1991	13,198	25,819	24,390	47,464	46,888	28,757	18,509	7,727	35,567	9,007	257,326	1.1%
1992	13,167	25,779	24,471	47,961	47,111	29,103	18,603	7,793	36,017	9,150	259,155	0.7%
1993	13,161	25,699	24,485	48,345	47,224	29,395	18,660	7,839	36,285	9,237	260,330	0.5%
1994	13,188	25,677	24,521	48,717	47,340	29,637	18,712	7,881	36,531	9,292	261,496	0.4%
1995	13,233	25,704	24,586	49,082	47,415	29,852	18,752	7,914	36,797	9,339	262,674	0.5%
1996	13,277	25,753	24,645	49,395	47,419	30,070	18,768	7,941	37,082	9,379	263,729	0.4%
1997	13,328	25,796	24,711	49,678	47,410	30,261	18,784	7,964	37,361	9,401	264,694	0.4%
1998	13,375	25,821	24,773	49,957	47,417	30,412	18,803	7,985	37,618	9,417	265,578	0.3%
1999	13,410	25,822	24,829	50,233	47,430	30,546	18,824	8,006	37,854	9,436	266,390	0.3%
2000	13,431	25,804	24,886	50,496	47,443	30,670	18,849	8,029	38,073	9,456	267,137	0.3%
2001	13,438	25,773	24,936	50,741	47,519	30,755	18,924	8,053	38,243	9,467	267,849	0.3%
2002	13,456	25,757	24,986	50,992	47,485	30,834	18,905	8,072	38,394	9,481	268,362	0.2%
2003	13,466	25,732	25,021	51,220	47,426	30,911	18,873	8,087	38,525	9,494	268,755	0.1%
2004	13,463	25,687	25,059	51,437	47,358	30,995	18,834	8,103	38,663	9,508	269,107	0.1%
2005	13,445	25,616	25,110	51,654	47,275	31,081	18,786	8,120	38,817	9,520	269,424	0.1%
2006	13,428	25,540	25,161	51,876	47,174	31,164	18,731	8,136	38,969	9,529	269,708	0.1%
2007	13,419	25,476	25,205	52,100	47,056	31,243	18,670	8,149	39,108	9,532	269,958	0.1%
2008	13,414	25,426	25,240	52,319	46,927	31,313	18,609	8,158	39,238	9,534	270,178	0.1%
2009	13,410	25,383	25,268	52,525	46,794	31,369	18,550	8,168	39,364	9,541	270,372	0.1%
2010	13,403	25,340	25,290	52,722	46,651	31,418	18,490	8,177	39,485	9,554	270,530	0.1%
1990-2000	0.17%	0.02%	0.28%	0.77%	0.20%	0.79%	0.25%	0.51%	0.88%	0.73%	0.49%	
2000-2010	-0.02%	-0.18%	0.16%	0.43%	-0.17%	0.24%	-0.19%	0.18%	0.36%	0.10%	0.13%	

ELECTRIC POWER GENERATION

Industrial Cogeneration

- NPC Reference Case scenarios developed from EEA cogeneration forecast proposed for the 1993 Edition of the GRI Baseline Projection
- In 1989, industrial cogeneration capacity was approximately 24,100 megawatts. Generation was approximately 146,000 million Kwh.
- High Reference case assumes that cogenerated power grows 6.6 percent per year through 1995:
 - 1995 installed capacity would be 42,700 MW and generation of 243,600 million Kwh, in middle of typical forecast ranges
 - One-half to two-thirds of increment is assumed to be exported (i.e., sold to utilities)
- Projected growth for total cogenerated power to slow to 2.7 percent after 1995, with capacity of 63,500 MW by 2010:
 - Less opportunity for cogeneration projects in industrial sector
 - Assumed weaker economic incentives for cogeneration as capacity credits are lost when new electric utility plants come on line after 1995
 - Institutional changes less advantages to cogeneration
- Cogenerated power from gas fired facilities is projected to also grow by 12.1% per year through 1995:
 - Installed capacity would increase to 23,600 MW by 1995 compared to 11,800 MW in 1989
- Increase in gas demand (vs. 1989) for cogeneration is 325 Bcf by 1995. Total cogen incremental gas demand of 814 Bcf. Incremental gas demand is the net energy input to produce electrical output, over and above energy required to produce steam.

- Growth of power production in gas-fired cogeneration facilities slows to 2.9% per annum after 1995
- By 2010, increase in cogeneration gas demand (vs. 1989) is 750 Bcf. Total incremental cogen gas demand is 1,240 Bcf.
- Low Reference Case modifies this scenario to reduce post-1995 growth of cogeneration by approximately 10 percent, reflecting impact of slower growth in industrial production.
- Gas demand in California EOR fields is projected to reach 275 Bcf in 1995, declining slowly through forecast period.

NUG Generation And Canadian Power Imports

- Generation scenario in this case is based on NERC 1990 forecast (through 1999-2000)
- In High Reference Case, Canadian electricity imports projected to increase from 1,980 million Kwh (net) in 1990 to 38,929 in 1995 and 66,014 by 2000. Regional allocation based on recent NEB forecast. (1990 Import levels were atypically low)
- Total non-utility generation (NUG's) projected to increase from 115,700 million Kwh in 1990 to 184,100 in 1995 and 248,000 in 2010. NUG generation composed of:
 - Industrial cogeneration sales to utility system
 - Large central-station independent power producers (IPP's)¹
 - Small power producers/QF's
- In Low Reference Case, growth rates in Canadian power imports, industrial cogeneration sales, and large IPP's reduced in proportion to change in growth rate for total purchased electricity.

¹ Reflects currently planned large IPP's, which are incorporated in model's electric utility sector as specific central-station powerplants (quasi-utility).

- Composition of NUG/power import scenario (millions Kwh)

	1990	1995	2000	2010
Canadian power imports	1,980	38,929	66,014	66,014
Purchased cogenerated power	58,393	106,276	133,579	164,049
Large IPP's ¹	8,187	26,821	27,689	27,689
Small IPP's/QF's ²	49,121	50,991	52,932	57,039
Total Generation	117,681	223,017	280,214	314,791
Growth Rate (%)		13.6%	4.7%	1.2%

- Composition of Lower-48 NUG/power import scenarios (millions Kwh) in Low Reference Case

	1990	1995	2000	2010
Canadian power imports	1,980	35,052	56,717	66,014
Purchased cogenerated power	58,393	106,276	130,245	158,272
Large IPP's ¹	8,187	26,821	27,689	27,689
Small IPP's/QF's ²	49,121	50,991	52,932	57,039
Total Generation	117,681	219,140	267,583	309,014
Growth Rate (%)		13.2%	4.1%	1.5%

¹ Reflects only specific, currently-announced large IPP projects in U.S. Northeast. Future (unannounced) projects of similar kind reflected as new utility system capacity additions. Model adds additional new, large central station capacity as required during forecast period.

² Non-fossil fuel power generators (e.g., landfill, wind, solar, etc.)

New Utility Generating Capacity

(1) Through 1987, fuel mix of new utility generating capacity based on announced plans of electric industry in 1991 NERC forecast. Announced plants not constructed by 1997 in

forecast case are "canceled" and replaced by generic gas/coal competition.

(2) Beyond 1997, new utility generating capacity is based on endogenous competition of coal and gas-fired units for baseload generating needs:

- The capital costs of coal fired plants are assumed to increase at 1.0 percent per year in real items. Capital costs of gas fired facilities assumed to increase at same rate.
- Assumed greater reliance on more expensive, lower sulfur coal in complying with environmental requirements.
- Added assumption that a portion of "old" oil/gas fired steam plants would be repowered, with a net increase in capacity (effectively adds new generating capacity which is oil/gas fired).
 - Total of 21,000 MW additional oil/gas capacity from repowering during 1991-2010 in High Reference Case; 15,000 MW in Low Reference Case.
 - Technology mix of incremental capacity: 40% steam, 60% combined cycle

(3) Between 1998 and 2005, "Institutional" factors not reflected in the utility model's long run cost minimization logic constrain the use of coal in new generating plants, favoring natural gas. These institutional factors affecting utility decisions until the late 1990's include:

- Perceptions which tend to understate natural gas prices in the future; utilities are slow to react to rising natural gas prices hence tend to understate future escalation in wellhead gas costs until the turn of the century.
- The combination of excess generating capacity in many regions, uncertain growth in electricity demands, utility financial problems and a regulatory attitude which makes recovery of capital costs in new plants uncertain, all lead utilities to bias fuel choice in new capacity toward oil/gas fired capacity because capital costs per KW are considerably less than for coal.
- In this uncertain environment utilities will tend to delay new construction decisions as long as possible, which also tends to favor the choice of oil/gas fired units since

their construction time is much shorter than for coal fired units.

- This environment is assumed to persist until near the end of the decade (years 1997-98) when: natural gas prices are clearly escalating, excess generating capacity has been worked off in most regions, utility financial woes have eased and regulators, recognizing the need for new generating capacity, adopt attitudes which once again encourage utilities to install more expensive, coal fired capacity.
- Due to long construction lead times between the date that new capacity choices are made and when new plants come on line, the long term economics of coal vs natural gas/oil costs becomes the dominant factor affecting the fuel mix between gas/oil and coal in new generating plants coming on line by the year 2005
- Hence, during the period 1998-2005 the choice of fuel firing capacity between natural gas/oil vis coal in new baseload generating plants was estimated, relying primarily on the fuel mix in currently announced plans to build new plants, rather than on strictly long term cost minimization.

CHAPTER FOUR
**DRI MODEL OUTPUT FOR
REFERENCE CASES**

THE ECONOMIC OUTLOOK

CASE 1

* * * * *

The High-Reference Case

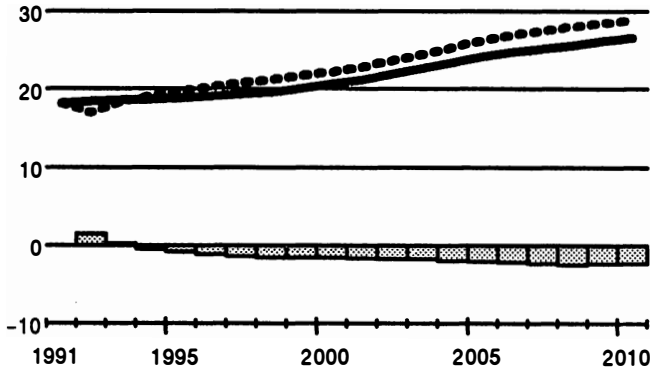
Prepared for
The National Petroleum Council
May 1992

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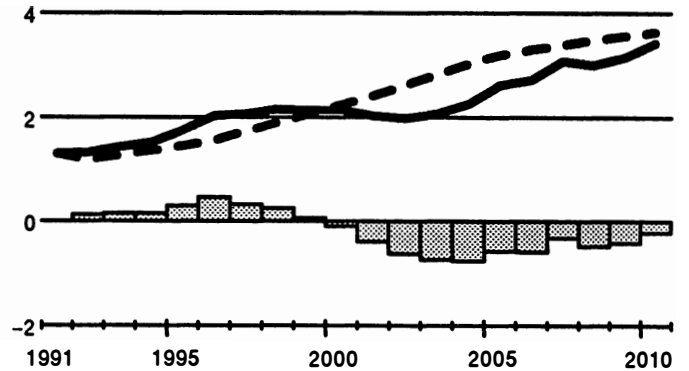
Prepared by
Christopher Probyn
DRI/McGraw-Hill

A Comparison of NPC and DRI Forecasts

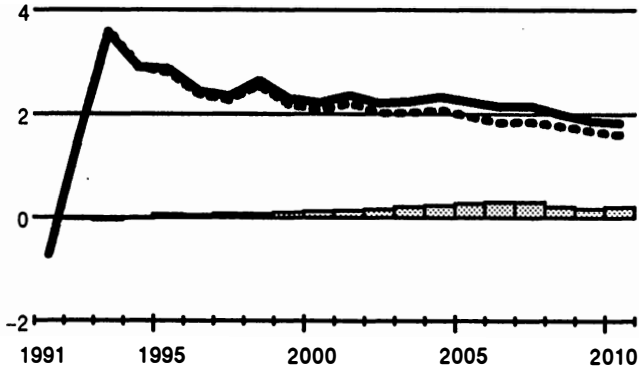
Refiners' Acquisition Price of Foreign Crude Oil
(1990 dollars, dollars per barrel)



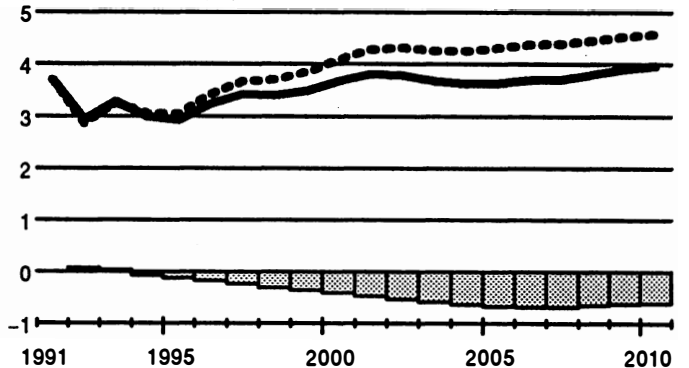
Tx/Gulf Spot Wellhead Price of Natural Gas
(1990 dollars per mmbtu)



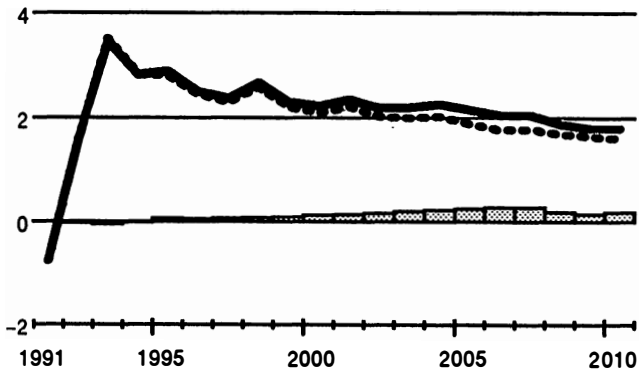
Real GNP
(Percent change)



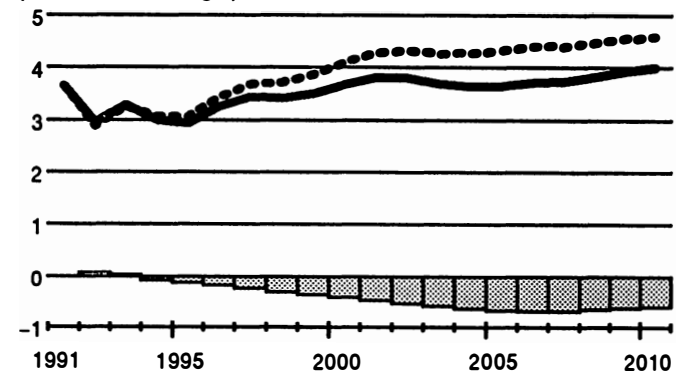
Implicit GNP Deflator
(Percent change)



Real GDP
(Percent change)



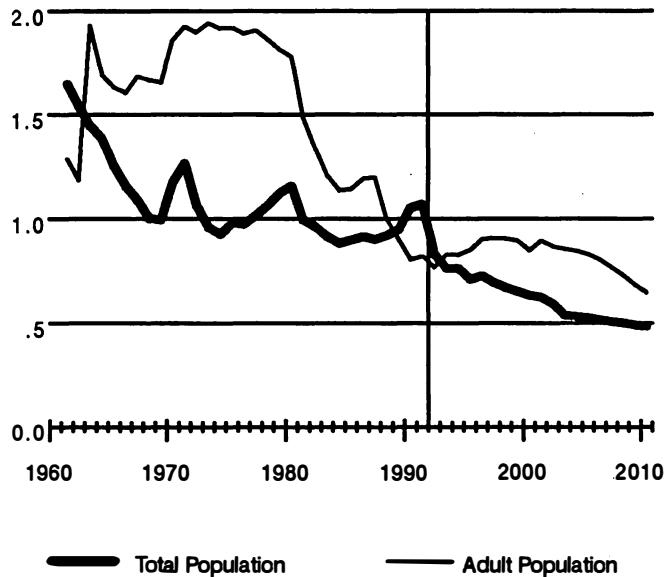
Implicit GDP Deflator
(Percent change)



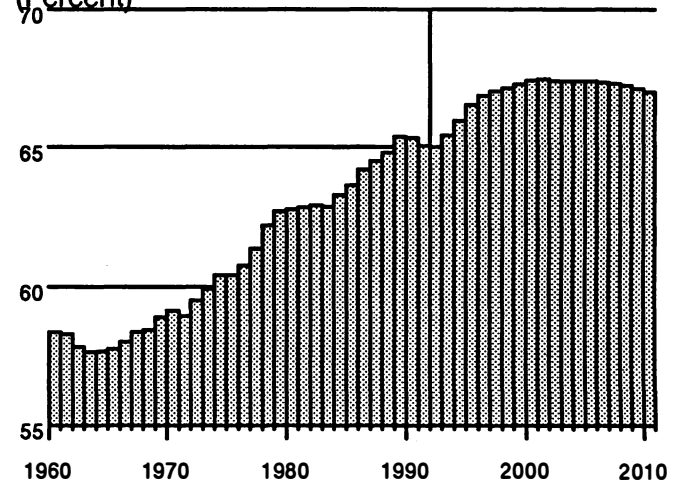
— NPC ····· DRI [shaded box] Difference

NPC Forecast—A Graphic Summary

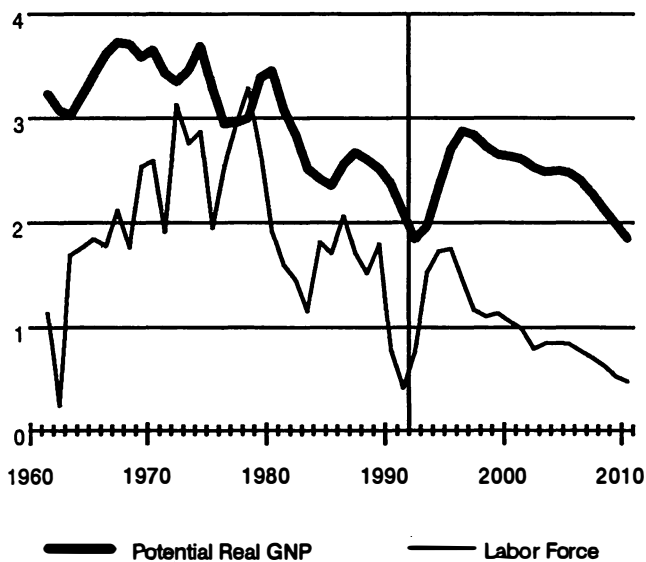
Population Growth Slows
(Percent change)



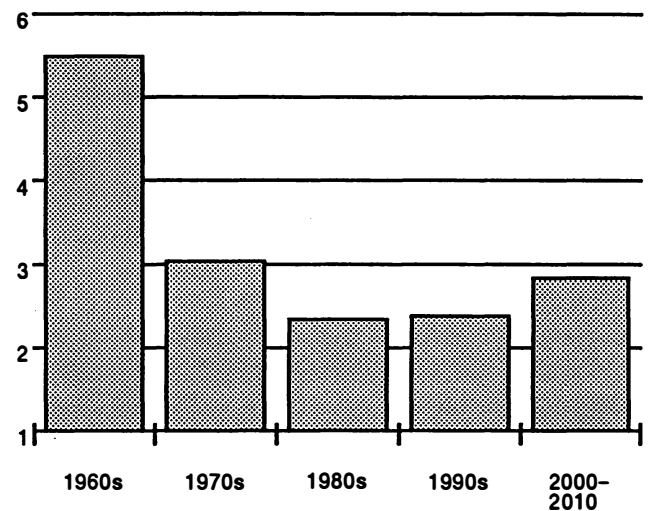
The Civilian Labor-Force Participation Rate Levels Off
(Percent)



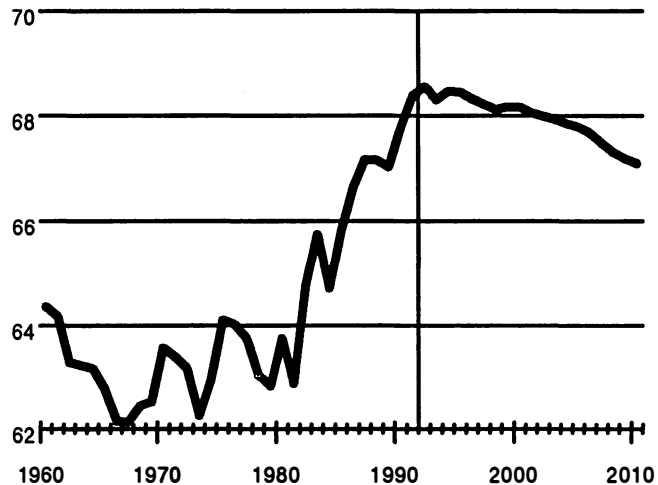
Slower Growth in the Labor Force Limits Gains in Potential Output
(Percent change)



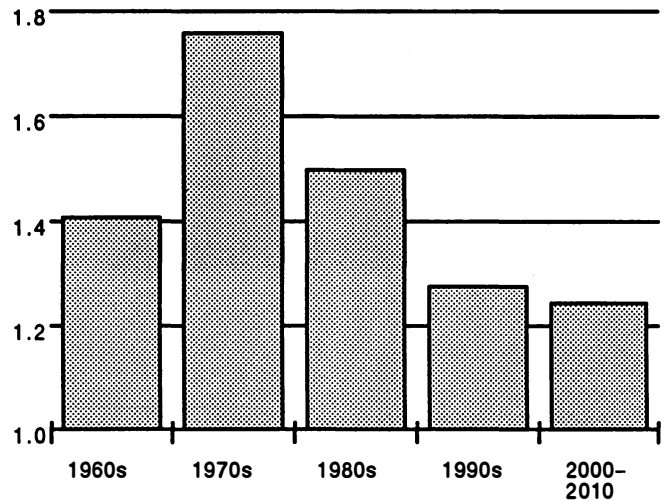
Industrial Production Growth Remains Flat
(Average annual percent change)



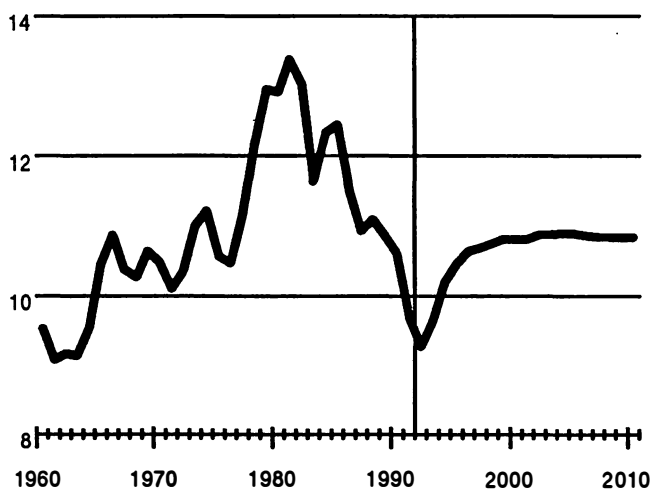
Consumption Retreats Slightly
(Percent of GNP)



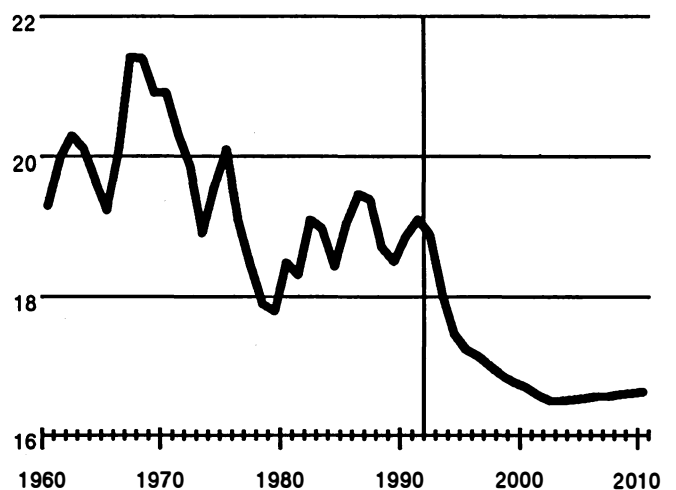
Housing Starts Decline from 1970s Peak
(Average annual rate, millions of units)



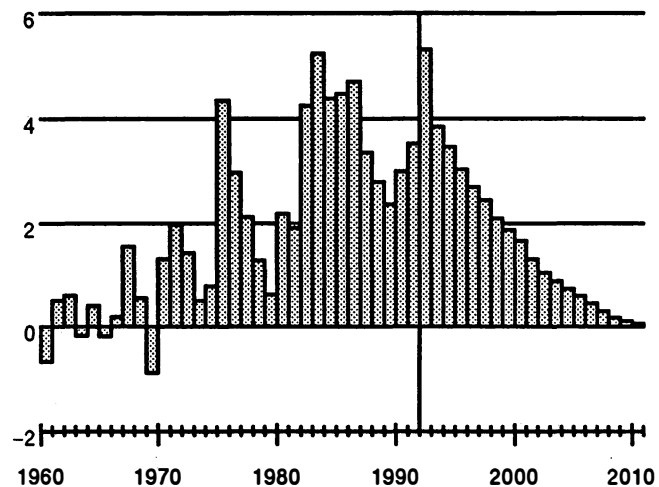
Business Fixed Investment Surges Back in the Near Term
(Percent of GNP)



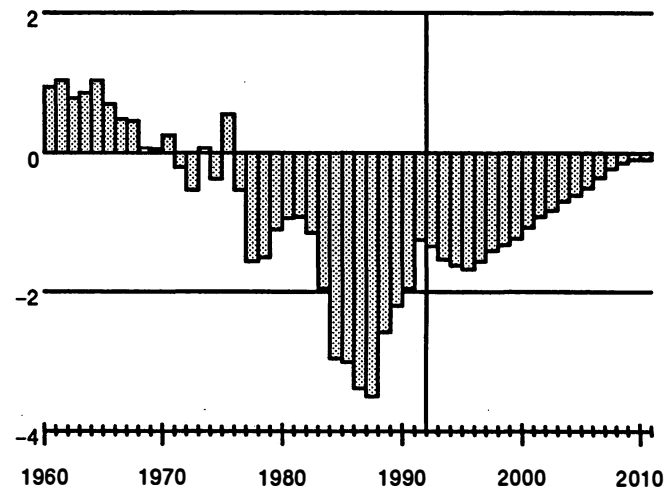
...As Government Spending Recedes
(Percent of GNP)



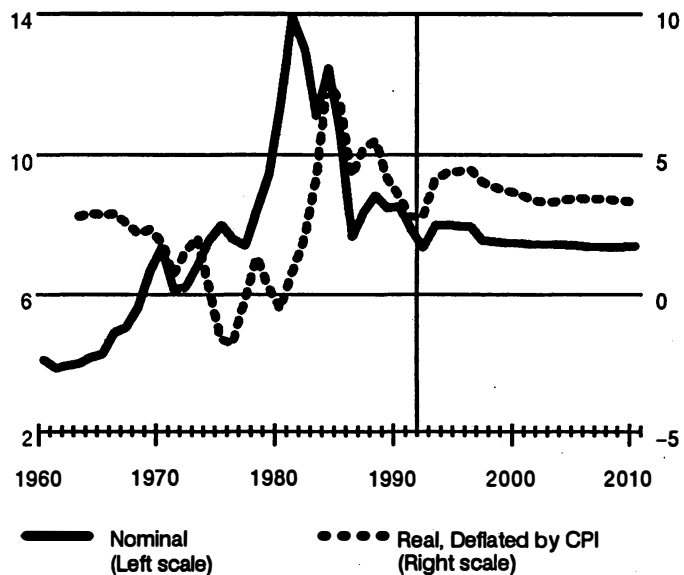
The Federal Deficit Improves Steadily
(Percent of GNP)



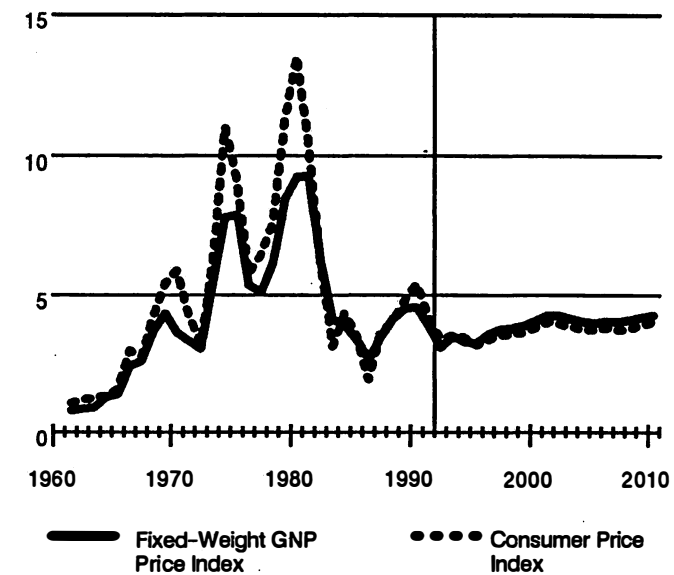
The Merchandise Trade Deficit
Steadily Improves
(Percent of GNP)



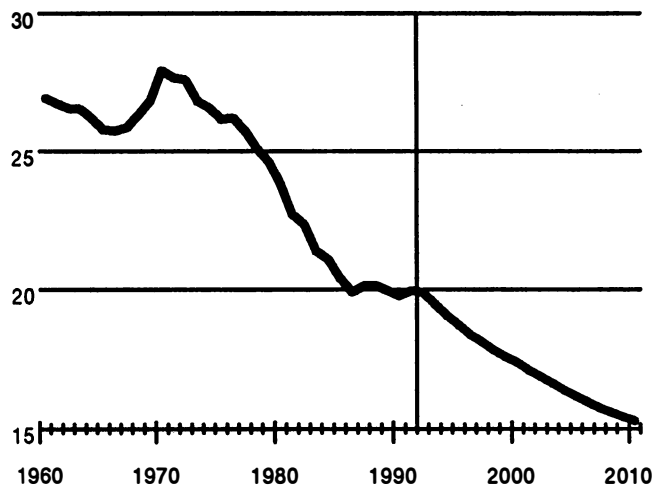
Real Interest Rates Moderate, But
Remain High Relative to History
(Ten-year bond yield, percent)



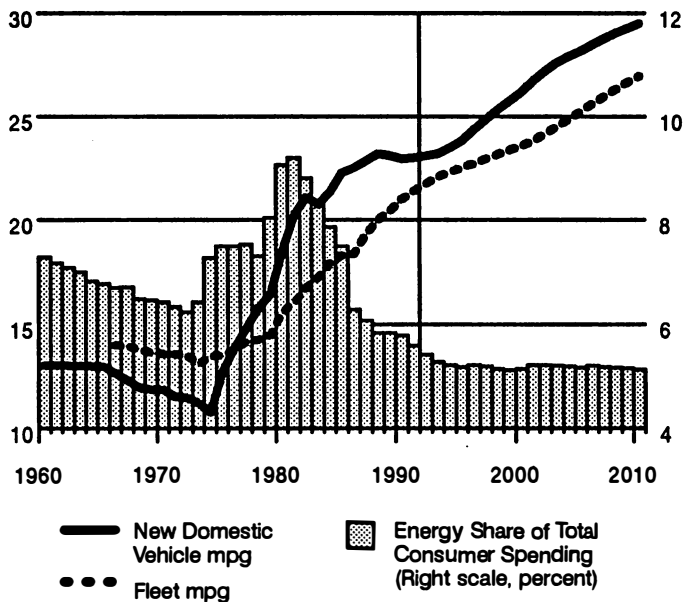
Inflation Remains Moderate
(Percent change)



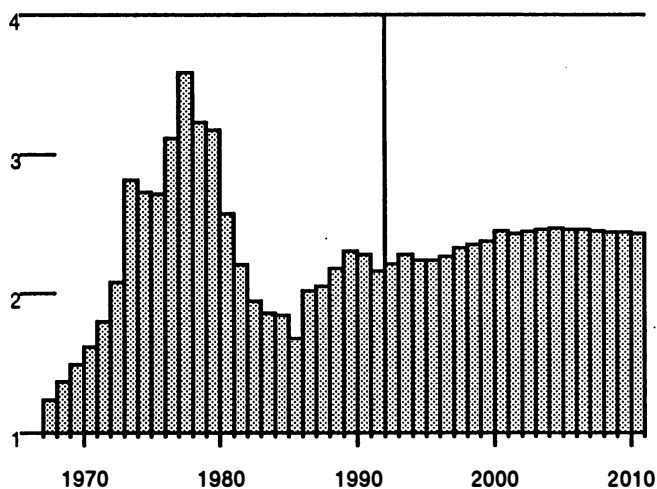
The Energy-to-GNP Ratio Keeps Falling
(Thousands of Btus per 1982 dollar of GNP)



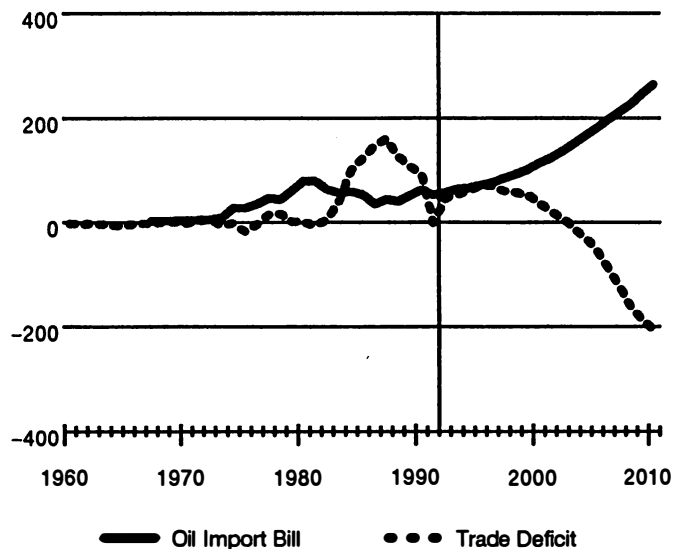
Consumers Continue to Spend Proportionately Less on Energy



Oil Import Volume Relative to Real GNP Remains Stable
(Percent)



The Oil Import Bill Exceeds the Trade Deficit in the Late 1990s
(Billions of dollars)



NPC Forecast

DRI/McGraw-Hill Summary Table for the U.S. Economy

	YEARS							Average Annual Compound Growth			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Composition of Real GNP (Annual rate of change)											
Gross Domestic Product	1.0	-0.6	1.7	3.2	2.5	2.4	1.9	2.2	2.7	2.6	2.1
Gross National Product	1.1	-0.6	1.7	3.1	2.5	2.5	2.0	2.2	2.7	2.6	2.2
Final Sales	1.8	-0.2	1.4	3.2	2.5	2.5	1.9	2.1	2.7	2.6	2.2
Excluding CCC Transactions	1.9	-0.3	1.4	3.2	2.5	2.5	1.9	2.1	2.7	2.6	2.2
Total Consumption	1.1	-0.3	1.4	2.5	1.9	1.9	1.6	1.9	2.0	1.9	1.6
Nonresidential Fixed Investment	1.7	-4.6	3.5	7.2	3.8	2.9	2.5	5.5	4.7	4.0	2.6
Equipment	2.7	-0.9	8.3	6.6	4.3	3.1	2.8	7.6	5.0	4.4	2.8
Structures	-0.5	-13.4	-9.2	9.4	2.0	2.2	1.5	-0.2	3.5	2.4	1.6
Residential Fixed Investment	-8.7	-10.4	9.6	6.8	1.2	0.6	1.9	3.6	2.2	0.3	1.2
Exports	6.5	4.9	4.2	6.4	6.7	5.2	3.4	6.2	6.8	6.1	4.2
Imports	1.5	-0.5	6.1	5.3	4.3	3.3	2.8	5.7	4.4	4.1	2.8
Federal Government	1.5	1.1	-0.9	-4.0	-0.8	1.6	1.2	-3.4	-1.6	0.5	1.4
Excluding CCC Transactions	1.9	0.6	-0.8	-4.0	-0.8	1.6	1.2	-3.4	-1.6	0.5	1.4
State and Local Governments	4.5	0.7	1.0	3.6	1.4	1.4	1.1	2.0	2.0	1.3	1.2
Billions of Dollars											
Real GNP (1982 \$)	4,121.8	4,097.5	4,165.4	4,596.1	5,247.1	5,965.2	6,643.9	2.2	2.7	2.6	2.2
Gross National Product	5,524.6	5,684.7	5,943.7	7,128.9	9,494.1	12,731.3	16,941.1	5.2	5.9	6.0	5.9
Prices and Wages (Annual rate of change)											
GNP Price Deflator (Implicit)	4.1	3.5	2.8	2.6	3.4	3.4	3.8	3.0	3.1	3.4	3.6
GNP Price Index (Fixed-Weight)	4.6	3.9	3.1	3.3	4.1	4.0	4.3	3.4	3.8	4.1	4.1
CPI—All Urban Consumers	5.4	4.2	3.4	3.2	3.8	3.8	4.0	3.6	3.6	3.9	3.9
Producer Price Index—Finished Goods	4.9	2.1	2.5	2.7	3.7	3.7	4.0	2.7	3.3	3.8	3.8
Employment Cost Index—Total Comp.	5.0	4.4	3.9	4.3	5.1	5.0	5.2	4.1	4.9	5.2	5.1
Output per Hour	0.0	0.3	1.7	1.4	1.8	1.7	1.6	1.3	1.8	1.9	1.6
Production and Other Key Measures											
Industrial Production (1987=1.000)	1.092	1.071	1.092	1.213	1.412	1.649	1.862	2.1	3.1	3.2	2.5
Annual Rate of Change	1.0	-1.9	2.0	3.2	3.1	2.8	2.2	2.1	3.1	3.2	2.5
Nonfarm Inven Accum (Billion 1982 \$)	-0.7	-14.0	-3.9	20.0	20.2	27.7	33.1	NM	0.2	6.5	3.6
Housing Starts (Mil units)	1.203	1.011	1.148	1.376	1.353	1.192	1.234	2.7	-0.3	-2.5	0.7
Retail Unit Car Sales (Mil units)	9.5	8.4	8.7	10.4	10.8	11.1	11.1	1.8	0.7	0.6	0.1
Civilian Unemployment Rate (%)	5.5	6.8	7.0	5.7	5.8	5.7	5.8	0.4	0.4	0.0	0.1
Nonfarm Empl.	1.5	-0.9	0.6	2.2	1.0	0.8	0.6	1.3	1.2	0.9	0.7
Fed. Budget Surplus (Unified, FY, bil. \$)	-236.1	-265.7	-451.2	-202.4	-151.8	-108.7	-97.4	3.0	5.6	6.5	2.2
Foreign Trade											
Current Account Balance (Billion \$)	-92.128	1.564	-44.756	-69.560	-37.339	53.621	206.458	5.5	11.7	NM	30.9
Merch. Trade Balance (c.v.b., bil. \$)	-101.7	-62.7	-69.4	-106.6	-83.5	-37.7	22.2	-1.0	4.8	14.7	NM
Foreign Crude Oil (\$ per barrel)	22.22	18.83	19.65	22.00	28.48	40.03	52.96	-0.2	5.3	7.0	5.8
U.S. Dollar Exchange Rate (% change)	-5.2	-1.1	0.5	-1.0	-1.1	-0.8	-0.4	0.0	-1.1	-1.0	-0.6
Foreign GDP (% change)	3.0	2.2	2.3	3.9	3.9	3.6	3.1	3.2	3.9	3.8	3.3
Financial Markets											
Money Supply (M2, billion \$)	3,325.3	3,416.0	3,591.9	4,251.6	5,863.4	7,899.6	10,380.1	5.0	6.6	6.1	5.6
Percent Change vs Year Ago (Q4/Q4)	3.8	2.7	5.1	6.1	6.7	5.8	5.6	5.0	6.6	6.1	5.6
AA Corp Utility Rate (%)	9.66	9.10	8.77	9.24	8.91	8.91	8.80	-0.9	-0.7	0.0	-0.3
Thirty-Year Treasury Bond Rate (%)	8.61	8.14	7.73	8.09	7.49	7.35	7.29	-1.2	-1.5	-0.4	-0.2
Treasury Bill Rate (%)	7.49	5.38	3.92	6.33	5.84	5.80	5.74	-3.3	-1.6	-0.2	-0.2
Federal Funds Rate (%)	8.10	5.69	3.92	7.00	6.50	6.50	6.49	-2.9	-1.5	0.0	0.0
Prime Rate (%)	10.01	8.46	6.41	9.00	8.00	8.00	7.99	-2.1	-2.3	0.0	0.0
S&P Index of 500 Common Stocks	335	376	417	476	652	830	1,132	7.3	6.5	4.9	6.4
Incomes											
Personal Income (Billion \$)	4,679.8	4,833.9	5,063.8	6,117.7	8,131.6	10,872.0	14,365.4	5.5	5.9	6.0	5.7
Real Disposable Income (% change)	1.8	-0.2	1.3	2.6	1.8	2.0	1.6	1.9	1.9	1.9	1.7
Saving Rate (%)	5.1	5.3	5.3	5.5	5.3	5.3	5.4	1.5	-0.9	0.1	0.4
Profits After Tax (Billion \$)	197.0	187.8	212.5	288.0	363.5	425.8	606.7	7.9	4.8	3.2	7.3
Post-Tax Corp Cash Flow (Billion \$)	549.1	566.5	638.2	760.1	1,001.4	1,290.3	1,760.2	6.7	5.7	5.2	6.4
Percent Change vs Year Ago	-2.7	3.2	12.6	6.1	5.1	5.0	6.8	6.7	5.7	5.2	6.4

NPC Forecast

U.S. Energy Outlook Summary

	YEARS							Average Annual Compound Growth			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Demand for All Fuels											
Total Energy Demand (Quad Btus)	81.4	81.8	82.8	86.0	91.1	96.3	101.4	1.1	1.2	1.1	1.0
Annual Rate of Change	0.1	0.5	1.2	1.2	1.3	1.1	1.0	1.1	1.2	1.1	1.0
Real GNP (% change)	1.1	-0.6	1.7	3.1	2.5	2.5	2.0	2.2	2.7	2.6	2.2
Energy Use Ratios											
Million Btus per Capita	325.6	323.6	324.8	329.9	338.0	347.4	356.8	0.3	0.5	0.6	0.5
Thousand Btus per 1982 \$ GNP	19.8	20.0	19.9	18.7	17.4	16.1	15.3	-1.1	-1.5	-1.4	-1.1
Prices (Dollars per barrel)											
U.S. Refiners' Acquisition Price											
for Crude Oil—Composite	22.35	19.14	19.57	21.86	28.33	39.84	52.73	-0.4	5.3	7.1	5.8
Annual Rate of Change	24.4	-14.4	2.3	4.0	6.3	7.2	5.7	-0.4	5.3	7.1	5.8
Domestic											
Annual Rate of Change	22.44	19.37	19.50	21.72	28.13	39.53	52.30	-0.6	5.3	7.0	5.8
Foreign											
Annual Rate of Change	25.5	-13.7	0.7	3.9	6.3	7.2	5.7	-0.6	5.3	7.0	5.8
Foreign (1990 \$)											
Annual Rate of Change	22.22	18.83	19.65	22.00	28.48	40.03	52.96	-0.2	5.3	7.0	5.8
Prices (Percent change)											
Producer Price Index—Fuel and Power											
Coal	12.8	-1.3	1.2	3.2	7.1	6.4	5.8	2.1	5.0	6.7	5.8
Natural Gas	2.1	-0.3	1.7	3.0	4.7	5.2	5.2	2.3	4.5	5.1	5.2
Electricity	4.1	-1.9	5.3	2.0	12.2	8.0	7.6	1.7	6.6	9.8	7.6
Domestic Crude Oil (NSA)	2.5	5.7	1.6	1.4	5.1	4.3	4.7	2.1	2.8	4.4	4.6
Refined Petroleum Products	26.1	-12.7	-0.2	3.9	6.3	7.2	5.7	-0.6	5.3	7.0	5.7
Residual Fuels	22.3	-10.4	2.0	4.8	6.4	6.2	5.3	1.5	5.6	6.4	5.3
Producer Price Index—Industrial	21.4	-18.9	3.0	4.9	6.8	7.5	5.9	0.6	5.7	7.6	6.0
Personal Consumption Deflator—Energy	3.8	0.6	1.2	2.6	4.0	4.0	4.3	1.9	3.5	4.1	4.1
Gasoline	8.6	0.8	1.8	3.6	5.6	5.0	5.1	2.3	4.7	5.4	5.1
Fuel Oil and Coal	14.0	-1.5	0.7	5.2	5.9	5.3	4.9	2.3	6.2	6.1	5.3
Electricity	20.4	-3.7	1.7	3.6	4.8	5.3	4.6	2.4	3.7	5.5	4.7
Natural Gas	2.4	3.8	2.4	1.5	5.0	4.5	5.1	1.9	2.7	4.4	4.9
Personal Consumption Deflator	0.1	1.3	3.6	2.7	6.3	5.3	5.7	2.4	5.0	5.9	5.5
Gasoline Tax (Cents per gallon)	5.3	4.2	3.4	3.2	4.0	3.8	4.1	3.5	3.7	4.0	4.0
Federal	25.7	31.7	32.7	36.2	47.8	62.3	80.1	7.1	5.7	5.4	5.2
State and Local	10.5	15.1	15.1	15.1	20.1	25.1	30.1	7.5	5.9	4.5	3.7
	15.2	16.6	17.6	21.1	27.8	37.2	50.0	6.8	5.6	6.1	6.1

U.S. Energy Outlook Summary (Continued)

	YEARS							Average Annual Compound Growth			
								1990	1995	2000	2005
	1990	1991	1992	1995	2000	2005	2010	1990	1995	2000	2005
Real Personal Consumption (Percent change)											
Household Energy Consumption	-2.9	-0.6	-0.3	1.3	0.8	0.5	0.3	0.8	0.9	0.6	0.3
Gasoline	-1.9	-2.3	-1.6	0.7	0.6	0.2	-0.1	-0.2	0.6	0.2	-0.1
Fuel Oil and Coal	-13.0	-3.9	1.6	0.4	0.1	-0.2	-0.3	0.0	0.0	0.0	-0.3
Electricity	0.4	3.3	-0.2	2.8	1.8	1.4	1.1	2.4	2.0	1.5	1.3
Natural Gas	-8.0	-0.6	4.2	0.2	-0.3	-0.3	-0.5	1.4	-0.1	-0.3	-0.4
Total Consumption	1.1	-0.3	1.4	2.5	1.9	1.9	1.6	1.9	2.0	1.9	1.6
Energy Share of Consumption (%)											
1982 Dollars	7.6	7.6	7.4	7.2	6.8	6.4	6.0	-1.1	-1.1	-1.3	-1.3
Current Dollars	5.8	5.6	5.4	5.2	5.1	5.2	5.1	-2.2	-0.1	0.1	-0.2
Average Miles per Gallon	21.0	21.4	21.8	22.5	23.6	25.2	27.0	1.4	0.9	1.4	1.3
Imports of Petroleum and Products											
Billions of 1982 Dollars	94.1	88.4	92.1	102.8	128.4	146.7	161.4	1.8	4.6	2.7	1.9
Billions of Current Dollars	62.3	51.3	56.8	70.2	113.1	181.6	264.6	2.4	10.0	9.9	7.8
Import Bill as Percent of GNP	1.13	0.90	0.96	0.98	1.19	1.43	1.56	-2.7	3.9	3.7	1.8
Industrial Production											
Oil and Gas Extraction (% change)	0.0	0.3	-4.9	-0.1	1.3	-0.8	-0.4	-1.4	-0.4	-1.2	-0.9
Piped Gas and Electric Utilities (% change)	0.9	0.6	1.6	2.1	2.8	1.6	1.2	1.7	1.9	1.6	1.3
Total Production (% change)	1.0	-1.9	2.0	3.2	3.1	2.8	2.2	2.1	3.1	3.2	2.5
Elec Util Fuel Use, Percent from:											
Coal	55.5	54.6	55.1	54.7	53.5	56.1	58.5	-0.3	-0.4	1.0	0.8
Natural Gas	9.3	9.1	8.8	9.8	11.2	10.6	9.7	1.1	2.8	-1.1	-1.9
Petroleum Products	4.2	4.2	3.8	4.0	4.8	4.8	4.8	-1.1	3.7	-0.1	-0.1
Hydro, Nuclear, Solar, and Other	31.0	32.0	32.3	31.5	30.5	28.5	27.1	0.4	-0.7	-1.3	-1.0

Comparison of the NPC and DRI Forecasts

Key Economic Indicators

(Compound average annual growth rates)

	NPC Forecast 1990–2010	DRI Forecast 1990–2010
Residential and Commercial Sectors		
Residential Building Stock	1.0	1.0
Commercial Floor Space	1.4	1.3
Disposable Income	1.8	1.8
Residential Population	0.6	0.6
Industrial Sector		
Food	1.7	1.6
Textiles	0.8	0.7
Paper	2.1	2.0
Chemicals	2.4	2.3
Petroleum Refining	0.5	0.5
Stone, Clay & Glass	1.4	1.3
Iron and Steel	0.0	–0.3
Nonferrous Metals	2.3	2.0
Other	3.0	2.8
Total Industrial	2.7	2.5
Real GNP	2.4	2.3
GNP Deflator	3.3	3.7

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/MTBEFIX.

RESIDENTIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal	72.7	73.2	73.0	72.9	72.8	72.6	71.8	70.8	69.7	-0.2	-0.1	-0.3
Natural Gas	4,526.7	4,658.1	4,822.0	4,797.6	4,789.0	4,771.1	4,701.1	4,630.7	4,468.6	3.5	0.4	-0.5
Petroleum	1,318.7	1,328.9	1,352.6	1,379.7	1,373.4	1,374.5	1,324.3	1,295.6	1,249.3	1.8	0.0	-0.6
Distillate Fuel	835.8	788.1	839.2	862.5	854.7	854.0	818.2	793.0	755.0	6.5	-0.2	-0.8
Liquefied Gases	423.1	449.3	433.9	436.9	437.4	438.3	427.6	426.9	421.3	-3.4	0.1	-0.1
Kerosene	59.8	91.5	79.5	80.3	81.3	82.2	78.5	75.6	73.1	-13.1	2.8	-0.7
Other	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	0.5	0.5	0.5
Total Direct Fuels	5,919.6	6,061.7	6,249.2	6,251.7	6,236.7	6,219.8	6,098.8	5,998.6	5,789.3	3.1	0.3	-0.5
Electricity	3,105.9	3,267.8	3,300.4	3,354.7	3,405.1	3,456.6	3,724.4	3,981.8	4,184.2	1.0	1.8	1.2
Losses	6,997.9	7,281.9	7,367.9	7,538.1	7,620.8	7,755.3	8,065.7	8,478.3	8,838.7	1.2	1.4	0.9
Total Primary Fuels	16,023.4	16,611.4	16,917.5	17,144.5	17,262.5	17,431.7	17,888.8	18,458.7	18,812.1	1.8	1.1	0.5
Primary Fuels Per Household	169.7	174.4	176.1	177.1	177.2	177.7	175.6	175.3	173.9	1.0	0.3	-0.1
Energy Use to GNP Ratio	2.19	2.28	2.30	2.25	2.20	2.15	1.94	1.77	1.64	1.0	-1.2	-1.7
Energy to GNP Ratio	3.89	4.05	4.07	4.01	3.94	3.87	3.54	3.27	3.08	0.5	-0.9	-1.4

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/M1BEFIX.

COMMERCIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal	91.3	91.9	91.8	91.6	91.4	91.2	90.2	88.9	87.6	-0.2	-0.1	-0.3
Natural Gas	2,763.0	2,855.0	2,963.7	2,999.9	3,036.3	3,062.3	3,210.3	3,516.1	3,741.0	3.8	1.5	1.5
Petroleum	898.4	863.5	893.3	892.4	886.8	883.3	852.0	825.8	814.3	3.4	-0.5	-0.5
Distillate Fuel	486.1	444.9	476.7	473.6	467.1	461.7	427.1	397.7	378.4	7.1	-1.3	-1.2
Residual Fuel	225.2	207.7	224.6	225.3	224.6	224.5	216.6	207.7	203.5	8.1	-0.4	-0.6
Gasoline	100.6	99.8	101.0	102.3	103.7	105.4	114.7	125.0	135.8	1.1	1.3	1.7
Kerosene	13.0	33.0	13.9	14.0	14.1	14.2	14.9	15.7	16.4	-57.9	1.4	1.0
Liquefied Gases	73.6	78.1	77.2	77.2	77.3	77.5	78.7	79.8	80.2	-1.2	0.7	0.2
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Total Direct Fuels	3,752.8	3,810.5	3,948.8	3,984.0	4,014.6	4,036.9	4,152.4	4,430.8	4,643.0	3.6	1.0	1.1
Electricity	2,804.2	2,846.0	2,850.9	2,921.3	3,009.0	3,094.0	3,353.9	3,529.8	3,668.6	0.2	1.8	0.9
Losses	6,318.1	6,341.9	6,364.3	6,564.1	6,734.5	6,941.8	7,263.4	7,516.1	7,749.6	0.4	1.4	0.7
Total Primary Fuels	12,875.1	12,998.3	13,164.1	13,469.4	13,758.1	14,072.6	14,769.7	15,476.7	16,061.2	1.3	1.4	0.8
Primary Fuels Per Square Foot Energy Use to GNP Ratio	279.0	276.8	276.2	279.2	281.4	283.7	275.2	258.0	241.8	-0.2	-0.1	1.3
Energy to GNP Ratio	1.59	1.62	1.64	1.61	1.60	1.58	1.49	1.41	1.36	0.8	-0.7	-0.9
Energy to GNP Ratio	3.12	3.17	3.17	3.15	3.14	3.13	2.92	2.74	2.63	-0.1	-0.7	-1.0

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/MTBEFIX.

INDUSTRIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal	2,792.8	2,607.7	2,706.5	2,712.4	2,690.7	2,687.4	2,398.6	2,285.6	2,181.3	3.8	-1.5	-0.9
Coking	1,067.3	924.6	983.9	1,007.5	992.3	997.3	717.1	524.6	382.0	6.4	-3.9	-6.1
Steam	1,723.8	1,681.0	1,722.6	1,704.9	1,698.4	1,690.1	1,681.5	1,761.0	1,799.3	2.5	-0.2	0.7
Natural Gas	8,459.2	8,521.7	8,709.0	8,764.7	8,794.4	8,850.9	9,195.6	9,714.3	9,458.1	2.2	0.8	0.3
Fuel and Power	7,185.6	7,294.8	7,501.4	7,570.7	7,624.8	7,708.5	8,072.9	8,601.6	8,413.2	2.8	1.2	0.4
Lease and Plant	1,273.6	1,226.9	1,207.6	1,194.0	1,169.6	1,142.3	1,122.6	1,112.7	1,045.0	-1.6	-1.3	-0.7
Petroleum	4,059.8	3,963.5	4,053.6	4,132.4	4,189.6	4,299.4	4,522.7	4,664.3	4,865.2	2.3	1.1	0.7
Distillate Fuel	1,178.6	1,116.9	1,132.1	1,145.4	1,160.3	1,182.6	1,290.0	1,350.3	1,391.8	1.4	0.9	0.8
Residual Fuel	385.1	346.1	358.3	411.8	436.7	506.7	557.7	575.7	695.1	3.5	3.8	2.2
Liquefied Gases	332.3	405.4	411.8	415.8	422.7	429.6	456.3	485.1	488.8	1.6	3.2	0.7
Kerosene	15.8	25.5	24.6	26.6	28.2	29.7	31.8	31.3	30.3	-3.6	7.2	-0.5
Gasoline	196.1	194.6	188.9	191.5	190.9	190.4	173.2	165.7	154.7	-3.0	-1.2	-1.1
Still Gas	1,379.8	1,331.0	1,381.5	1,383.2	1,389.4	1,395.6	1,430.3	1,457.2	1,488.1	3.8	0.4	0.4
Petroleum Coke	521.0	504.4	517.0	518.7	522.0	525.4	543.9	559.6	577.0	2.5	0.4	0.6
Crude Oil	51.0	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	0.0	-2.5	0.0
Hydropower	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	0.0	0.0	0.0
Other	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0
Total Direct Fuels	15,343.8	15,124.9	15,501.1	15,641.5	15,706.7	15,869.7	16,148.9	16,696.2	16,536.6	2.5	0.5	0.2
Electricity	3,160.1	3,132.3	3,161.9	3,221.1	3,235.7	3,296.9	3,513.8	3,697.1	3,867.4	0.9	1.1	1.0
Losses	7,119.9	6,979.8	7,058.6	7,237.8	7,241.7	7,396.9	7,609.8	7,872.2	8,169.5	1.1	0.7	0.7
Total Primary Fuels	25,623.7	25,237.0	25,721.6	26,100.4	26,184.0	26,563.5	27,272.5	28,265.6	28,573.5	1.9	0.6	0.5
Primary Fuels Per Real Value of Shipments	10.93	11.11	11.15	10.94	10.71	10.51	9.38	8.50	7.88	0.4	-1.5	-1.7
Energy Use to GNP Ratio	4.49	4.46	4.49	4.41	4.33	4.26	3.89	3.61	3.35	0.9	-1.4	-1.5
Energy to GNP Ratio	6.22	6.16	6.19	6.10	5.98	5.90	5.40	5.00	4.68	0.6	-1.4	-1.4

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/MTBEFIX.

RAW MATERIAL DEMAND FOR ENERGY
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Asphalt & Road Oil	1,166.3	1,053.8	1,041.1	1,048.2	1,059.0	1,076.0	1,152.4	1,185.8	1,204.7	-1.2	-0.1	0.4
Lubes & Waxes	396.1	353.8	375.0	385.4	391.8	398.4	428.2	461.8	482.9	6.0	0.8	1.2
Industrial Use	221.3	197.6	207.0	215.7	221.1	226.6	252.4	280.3	298.2	4.8	1.3	1.7
Transportation Use	174.8	156.2	168.0	169.7	170.7	171.8	175.8	181.5	184.7	7.5	0.1	0.5
Petroleum Coke	211.4	203.6	206.3	214.0	207.8	212.0	209.1	202.3	191.0	1.3	-0.1	-0.9
Special Naphthas	107.3	92.2	96.7	103.5	111.4	123.0	155.5	173.3	187.3	5.0	3.8	1.9
Other Petroleum Products *	126.4	-56.7	82.1	85.1	85.9	86.9	86.7	86.8	86.8	NM	-3.7	0.0
Petrochemical Feedstocks	2,389.7	2,455.9	2,435.8	2,349.2	2,289.4	2,314.2	2,677.0	2,857.5	3,026.1	-0.8	1.1	1.2
Liquefied Gases	1,194.5	1,216.2	1,202.1	1,186.5	1,154.6	1,166.4	1,351.9	1,445.9	1,534.2	-1.2	1.2	1.3
Naphtha	347.8	319.2	335.6	343.6	350.6	355.6	416.6	450.4	483.1	5.1	1.8	1.5
Still Gas	93.5	90.8	92.3	92.1	92.0	93.3	110.6	119.5	128.1	1.6	1.7	1.5
Miscellaneous	753.9	829.7	805.9	727.0	692.2	699.0	797.9	841.7	880.7	-2.9	0.6	1.0
Total	4,397.2	4,102.7	4,237.1	4,185.5	4,145.3	4,210.6	4,708.9	4,967.5	5,178.8	3.3	0.7	1.0
Total Delivered Fuel per Dollar of GNP **	1.07	1.00	1.02	0.98	0.95	0.94	0.93	0.88	0.85	1.9	-1.3	-0.9

* Other products include natural gasoline, isopentane, unfractionated stream, plant condensate, unfinished oils, motor gasoline blending components and aviation gasoline blending components. Due to inconsistencies in the classifications of some petroleum products, refinery inputs exceed total supply for these products, leaving a net negative balance.

** Thousand Btu per 1982 Dollar of GNP

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/MTBEFIX

TRANSPORTATION DEMAND FOR ENERGY
FUEL AND POWER USES
(Trillion Btu)

	YEARS									%CH -----	%CH -----	%CH -----
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Natural Gas	680.3	772.2	674.0	645.1	650.3	660.1	906.0	1,146.7	1,219.8	-12.7	2.9	3.0
Pipeline Fuel	680.3	772.2	674.0	645.1	650.3	653.8	715.0	770.5	776.0	-12.7	0.5	0.8
Vehicle Fuel	0.0	0.0	0.0	0.0	0.0	6.3	191.1	376.2	443.8	NC	NC	8.8
Petroleum	21,519.8	21,246.1	21,119.5	21,416.7	21,771.4	22,249.3	23,509.1	24,927.6	25,300.1	-0.6	0.9	0.7
Motor Gasoline	13,553.7	13,470.0	13,311.0	13,439.2	13,586.0	13,773.0	14,143.6	14,592.8	14,429.2	-1.2	0.4	0.2
Unreformulated	13,553.7	13,470.0	13,311.0	13,439.2	13,432.9	13,461.5	13,270.2	13,589.8	13,437.4	-1.2	-0.2	0.1
Oxygenate	0.0	0.0	0.0	0.0	153.1	311.5	873.4	1,003.0	991.9	NC	NC	1.3
Distillate Fuel	3,823.2	3,778.4	3,775.8	3,822.2	3,896.6	4,010.4	4,532.8	5,120.0	5,429.4	-0.1	1.7	1.8
Jet Fuel	3,129.4	3,023.9	3,038.1	3,127.3	3,238.1	3,359.9	3,625.0	3,900.3	4,062.6	0.5	1.5	1.1
Residual Fuel	948.1	910.6	931.7	964.4	985.9	1,038.7	1,136.4	1,240.3	1,302.0	2.3	1.8	1.4
Liquefied Gases	20.4	21.7	21.3	22.1	23.3	25.8	29.8	32.8	35.3	-1.9	3.9	1.7
Aviation Gasoline	45.0	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	0.0	-0.8	0.0
Total	22,200.1	22,018.3	21,793.5	22,061.8	22,421.7	22,909.4	24,415.2	26,074.3	26,519.9	-1.0	1.0	0.8
Electricity	18.1	24.4	19.6	19.7	20.0	20.2	21.1	21.9	22.5	-19.8	1.6	0.7
Primary Fuels Per Person	88.84	87.22	85.58	85.98	86.72	87.98	90.66	94.14	93.40	-1.9	0.2	0.3
Energy to GNP Ratio	5.39	5.38	5.25	5.16	5.12	5.10	4.84	4.62	4.35	-2.3	-1.1	-1.1

6/17/92

Version: NPCLOWREF

Workspace: NPC/ENG/WS/MTBEFIX.

ELECTRIC UTILITIES DEMAND FOR ENERGY
USED IN THE GENERATION OF ELECTRICITY
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal (1)	16,585.0	16,061.7	16,450.2	16,542.6	16,696.6	17,020.1	16,479.0	16,903.5	16,893.3	2.4	-0.1	0.2
Consumption	16,079.7	16,003.3	16,215.2	16,475.8	16,656.9	16,954.8	16,662.9	16,864.4	16,890.8	1.3	0.4	0.1
Stock Changes	417.6	58.4	235.1	66.8	39.7	65.3	-183.8	39.1	2.5	302.4	NM	NM
Natural Gas	2,854.1	2,848.2	2,785.4	2,978.7	3,066.9	3,085.1	4,327.3	5,181.4	5,577.0	-2.2	4.2	2.6
Petroleum (1)	1,376.9	1,286.6	1,029.8	1,135.2	1,136.6	1,401.8	1,435.4	1,652.5	2,402.6	-20.0	0.4	5.3
Residual Fuel (1)	1,263.2	1,198.1	967.3	1,053.8	1,058.6	1,293.1	1,311.4	1,481.6	2,132.3	-19.3	0.4	5.0
Consumption	1,140.1	1,206.8	978.9	1,031.2	1,050.6	1,246.7	1,338.1	1,436.5	2,071.2	-18.9	1.6	4.5
Stock Changes	123.1	-8.7	-11.6	22.6	8.0	46.4	-26.7	45.1	61.1	-33.5	NM	NM
Distillate Fuel (1)	101.8	76.9	56.1	75.0	71.6	102.4	117.7	164.5	264.0	-27.1	1.5	8.4
Consumption	86.4	77.5	64.0	69.8	72.3	87.1	116.9	142.7	230.8	-17.5	3.1	7.0
Stock Changes	15.4	-0.6	-7.9	5.3	-0.6	15.3	0.8	21.9	33.1	-1,223.5	-25.7	45.4
Other (1)	11.9	11.5	6.3	6.3	6.3	6.3	6.3	6.3	6.3	-44.9	-6.1	0.0
Nuclear Power	6,186.0	6,569.2	6,850.6	6,942.8	7,042.3	7,116.4	7,451.4	7,513.8	7,565.4	4.3	1.9	0.2
Hydropower	2,909.0	3,064.8	3,125.0	3,192.5	3,231.5	3,263.1	3,408.5	3,638.0	3,846.6	2.0	1.6	1.2
Other	200.0	196.4	206.3	222.1	222.8	231.5	357.4	338.7	310.8	5.0	6.0	-1.4
Total (2)	29,605.8	29,968.6	30,212.3	30,946.9	31,357.0	32,052.7	33,642.9	35,188.7	36,593.1	0.8	1.3	0.8
Total Electricity	9,100.8	9,282.9	9,346.7	9,530.9	9,683.8	9,881.8	10,627.4	11,245.0	11,757.2	0.7	1.6	1.0

LEGEND

(1) Product Supplied.

(2) Includes consumption of coal, product supplied of petroleum.

6/15/92

Version: NPCHIGHREF

Workspace: NPC/ENG/2.

TRANSPORTATION DEMAND FOR ENERGY
FUEL AND POWER USES
(Trillion Btu)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Natural Gas	680.3	772.2	675.8	650.5	658.8	668.9	921.7	1,161.5	1,238.0	-12.5	3.1	3.0
Pipeline Fuel	680.3	772.2	675.8	650.5	658.8	662.6	731.6	790.3	797.1	-12.5	0.7	0.9
Vehicle Fuel	0.0	0.0	0.0	0.0	0.0	6.3	190.1	371.3	440.9	NC	NC	8.8
Petroleum	21,519.8	21,246.1	21,107.1	21,446.4	21,853.4	22,352.5	24,030.0	25,575.4	26,833.0	-0.7	1.1	1.1
Motor Gasoline	13,553.7	13,470.0	13,315.9	13,480.7	13,672.5	13,894.2	14,510.3	15,017.5	15,258.8	-1.1	0.7	0.5
Unreformulated	13,553.7	13,470.0	13,315.9	13,480.7	13,518.4	13,580.0	13,614.6	13,985.7	14,210.7	-1.1	0.0	0.4
Oxygenate *	0.0	0.0	0.0	0.0	154.1	314.2	895.8	1,031.8	1,048.1	NC	NC	1.6
Distillate Fuel	3,823.2	3,778.4	3,775.1	3,829.1	3,914.9	4,035.6	4,616.9	5,254.5	5,798.9	-0.1	1.9	2.3
Jet Fuel	3,129.4	3,023.9	3,026.0	3,111.9	3,217.8	3,323.1	3,672.1	3,960.9	4,310.7	0.1	1.6	1.6
Residual Fuel	948.1	910.6	927.6	961.7	984.3	1,033.8	1,160.6	1,269.9	1,387.6	1.9	2.0	1.8
Liquefied Gases	20.4	21.7	21.0	21.5	22.5	24.4	28.6	31.1	35.4	-3.3	3.4	2.2
Aviation Gasoline	45.0	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	0.0	-0.8	0.0
Total	22,200.1	22,018.3	21,782.9	22,096.9	22,512.3	23,021.4	24,951.7	26,736.9	28,071.0	-1.1	1.2	1.2
Electricity	18.1	24.4	19.6	19.7	20.0	20.2	21.1	21.9	22.5	-19.8	1.6	0.7
Primary Fuels Per Person	88.84	87.22	85.54	86.12	87.07	88.41	92.65	96.53	98.85	-1.9	0.4	0.7
Energy to GNP Ratio	5.39	5.38	5.23	5.12	5.06	5.01	4.76	4.49	4.23	-2.7	-1.2	-1.2

*Incremental; Current (i.e. 1992) Levels of Oxygenate Use
are Imbedded in "Unreformulated" (Conventional) Fuel Category

CASE 1

WORLD OIL OUTLOOK

* * * * *

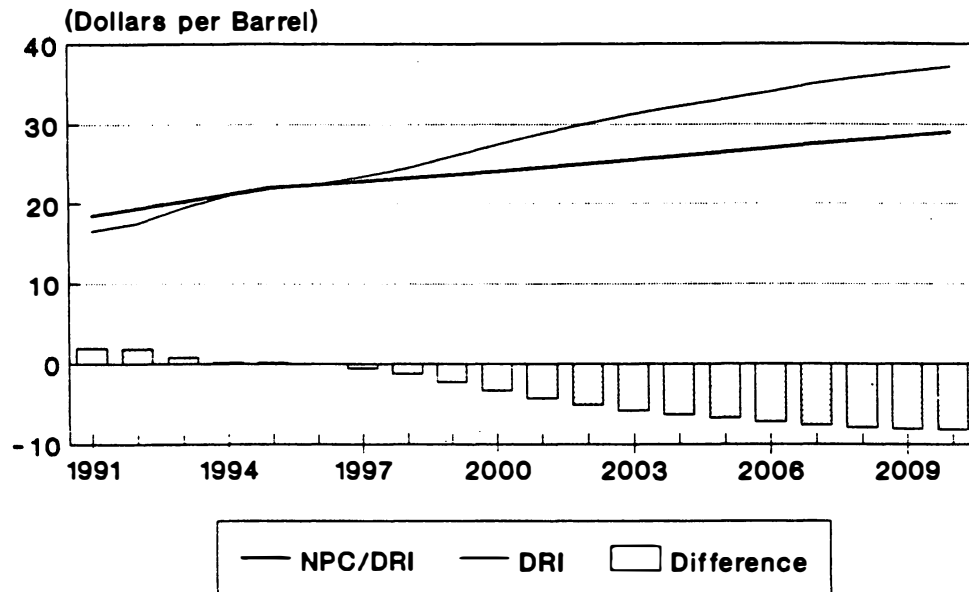
Prepared for
National Petroleum Council
Strawman Projection
May 16, 1991

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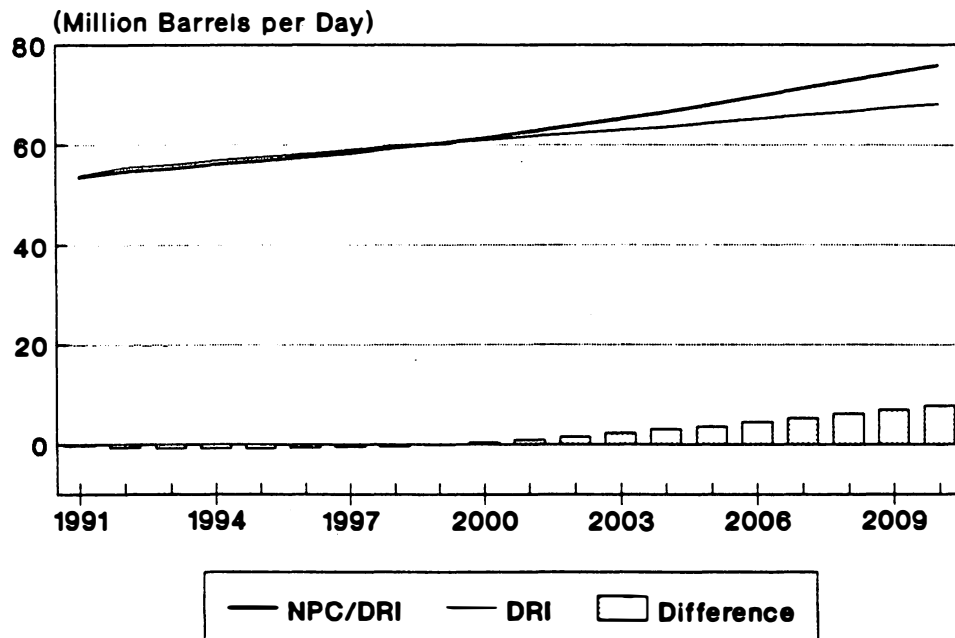
Prepared by
William R. Veno
DRI/McGraw-Hill

Comparison of NPC/DRI and DRI Base Cases

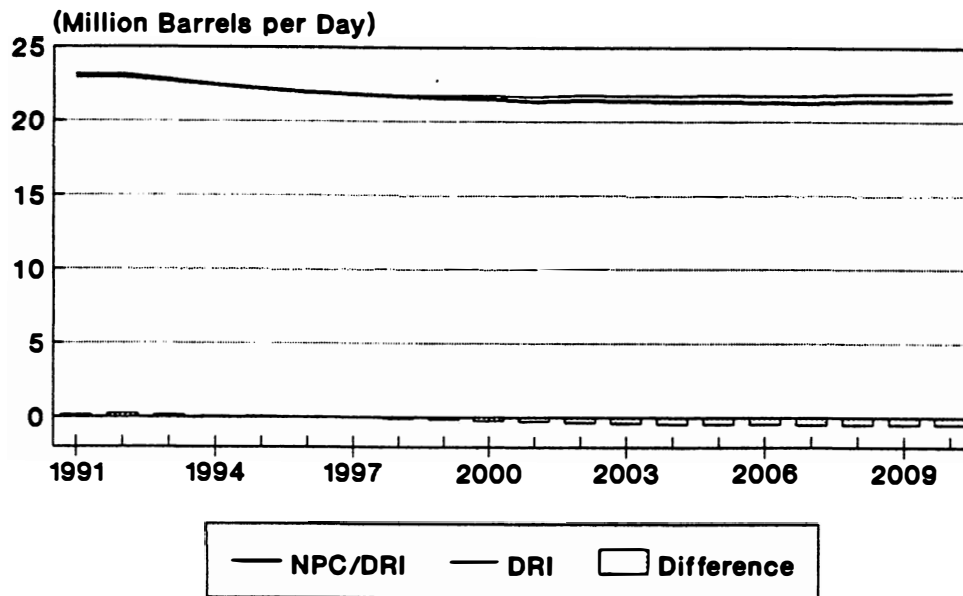
Average U.S. Refiner Cost of Foreign Crude



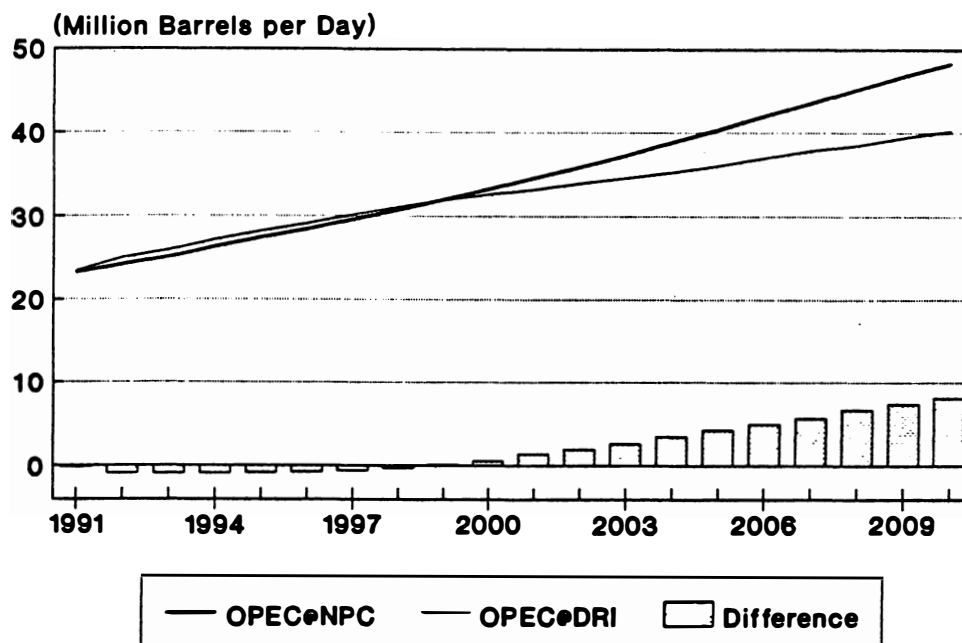
Non-Communist World Oil Consumption



Non-OPEC Crude Production (Excluding CPEs)



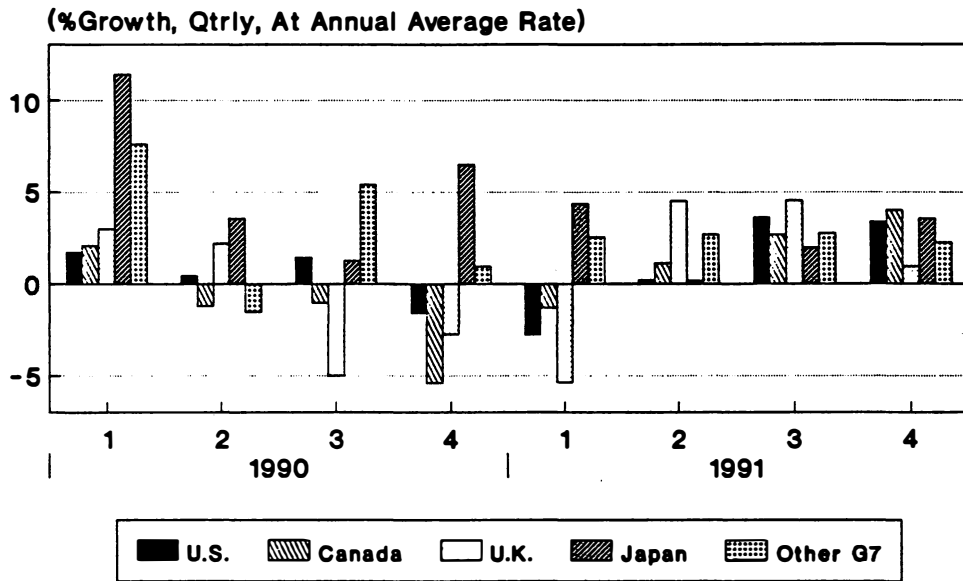
OPEC Crude Production



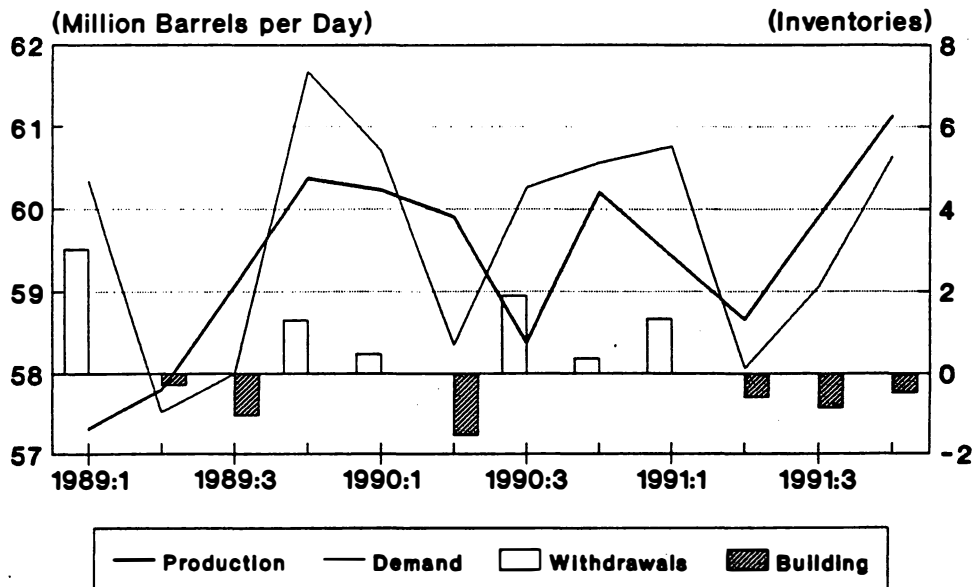
SHORT-TERM OUTLOOK: After the War

- **Return to Market Fundamentals**
- **Production Discipline is Key in Short Term, Led by Persian Gulf Producers, Especially Saudi Arabia**
- **Resumption of Kuwaiti and Iraqi Production will not be as Quick as Expected Prior to the War's End**
- **OPEC Production Cut is Required to Compensate for Weak World Economic Growth, Sluggish Oil Demand Growth and Seasonal Second-Quarter Downturn in Oil Demand**
- **Promised Cut in OPEC Production May Be Too Small to Avert Further Price Weakness**

World Economic Growth Burdened by Sluggish Anglo Economies



Ample World Crude Production Will Lead to Inventory Building



SHORT-TERM OUTLOOK: OPEC Restraint Critical for Price Growth

- **Excess Production and Weak Demand Exert Downward Pressure on Near-term Crude Prices**
- **Gradual Price Recovery Due to Improved Economic Growth and Faster Oil Demand Growth by Late 1991**
- **Eventual Restoration of Kuwaiti and Iraqi Production Presents Critical Test for OPEC Production Restraint**
- **Saudi Influence on OPEC Policy Greatly Expanded -- From 27% to 35% of OPEC Production (1990 vs. 1991)**
- **Crude Prices Will Rise Slowly From 2nd-Quarter 1991, With U.S. Refiner Prices Averaging \$20.50 In 1992**

SHORT-TERM OUTLOOK: Turmoil Surrounds OPEC Production/Pricing Policy

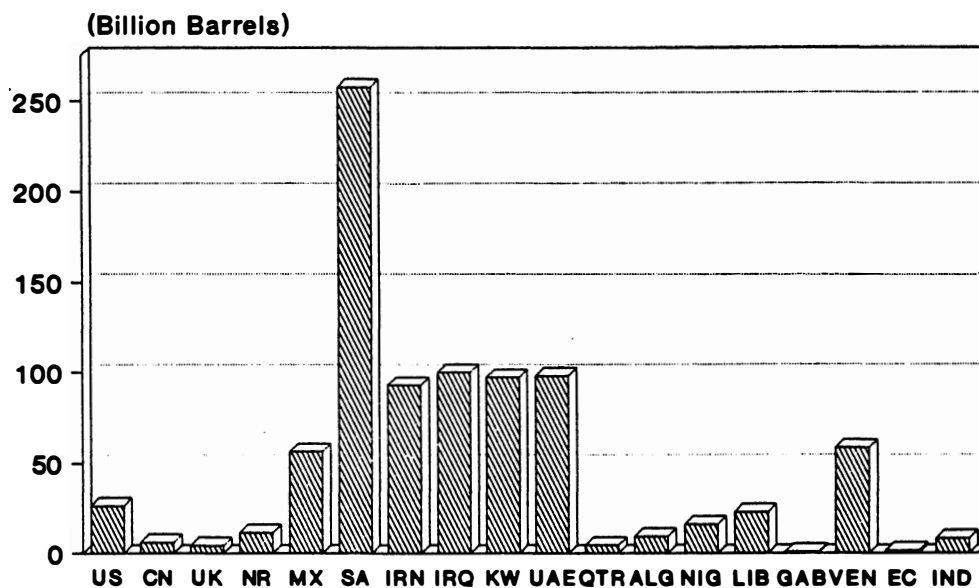
High Reserve Producers Want:

- Higher Volumes
- Lower, More Stable Oil Prices
- Steady Demand Growth
- Reduced Financial Incentive for Non-OPEC Producers
- These countries can generally tolerate lower oil export earnings.

Low Reserve Producers Want:

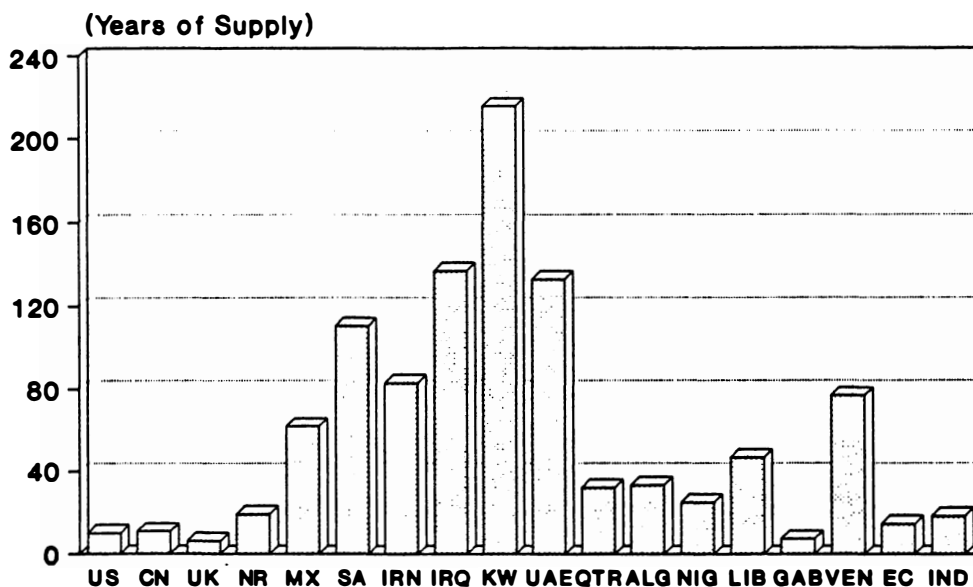
- Higher Prices
- Lower Production Volumes
- Extended Reserve Life
- Higher Short-Term Revenues
- Pressured by high debt and high population growth, these economies risk destabilization if export revenues are inadequate.

World Crude Reserves (As of 1/1/90)



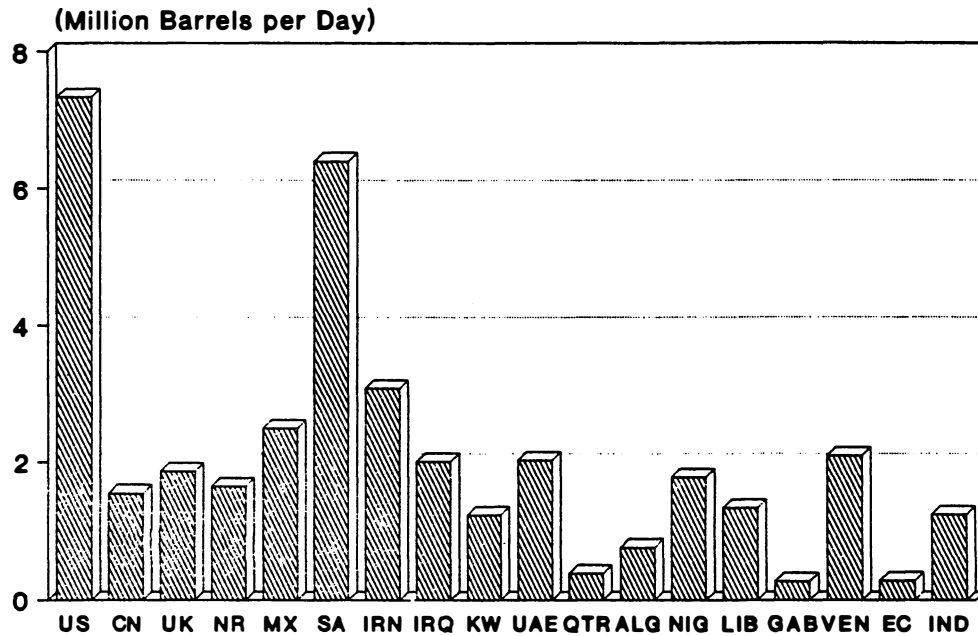
Source: Oil & Gas Journal

Reserve/Production Ratio (As of 1/1/90)



Source: Oil & Gas Journal

1990 World Crude Oil Production

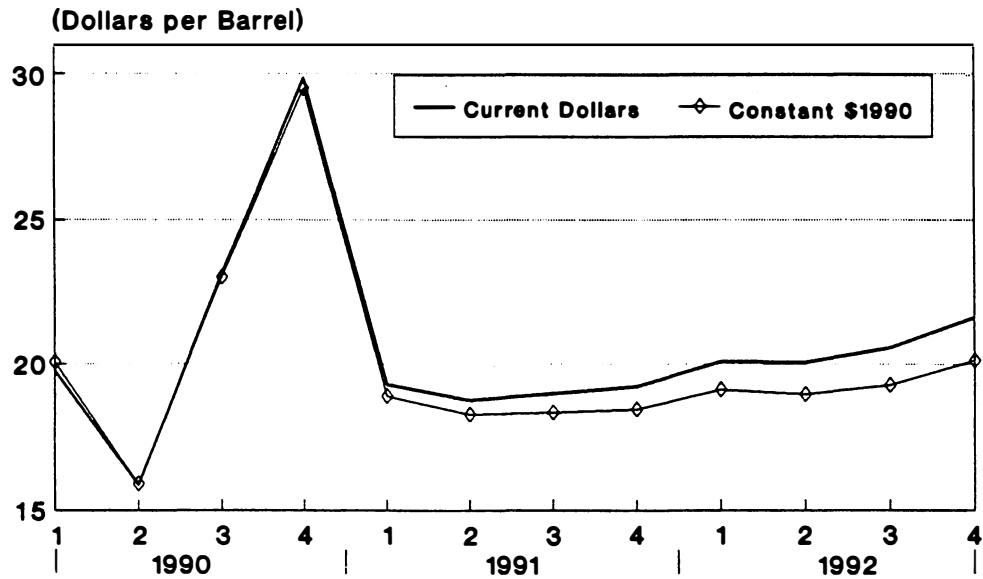


Source: Oil & Gas Journal

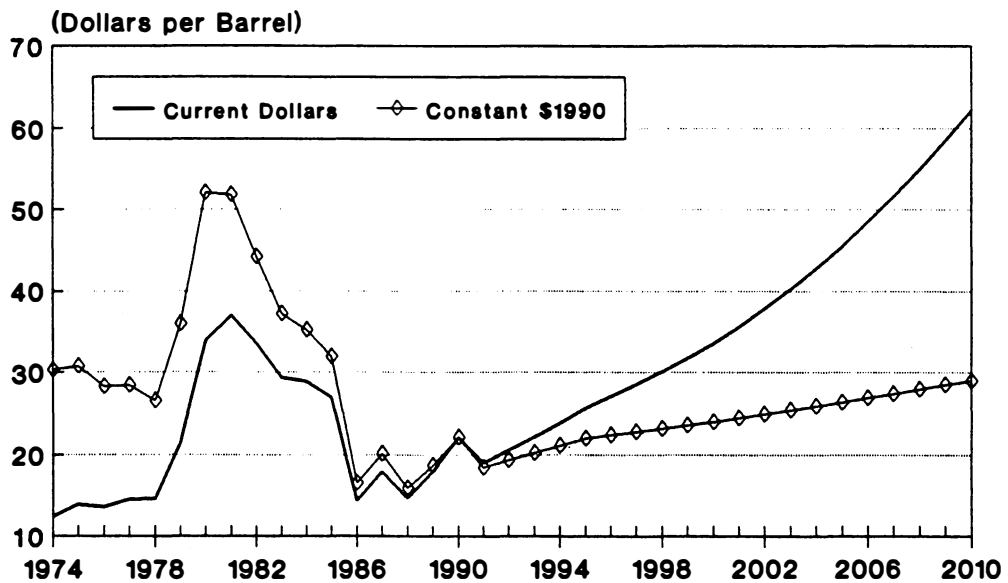
LEGEND FOR COUNTRY ABBREVIATIONS

US - United States
CN - Canada
UK - United Kingdom
NR - Norway
MX - Mexico
SA - Saudi Arabia
IRN - Iran
IRQ - Iraq
KW - Kuwait
UAE - United Arab Emirates
QTR - Qatar
ALG - Algeria
NIG - Nigeria
LIB - Libya
GAB - Gabon
VEN - Venezuela
EC - Ecuador
IND - Indonesia

Short-term U.S. Refiner Cost of Foreign Crude



Long-term U.S. Refiner Cost of Foreign Crude



SHORT-TERM OUTLOOK: U.S. Demand for Petroleum Products Weak

- Gains in Stock Average Fuel Economy Outpace Increasing Vehicle Miles Traveled and Lead to Declining Gasoline Consumption
- Weak On-Highway Diesel Demand Closely Tied to Economic Activity
- Reduced Competition and Higher Fares, Slowing Economy and Increasing Aircraft Efficiency Lead to Slower Growth in Jet Fuel Demand
- Gains in Electricity Generated From Nuclear and Hydro Displace Residual Fuel, but Depletion of Coal and Nuclear Pipeline Will Cause Later Rebound
- Tighter Environmental Regulations Will Strengthen Gasoline, Diesel Fuel and Low-Sulfur Residual Fuel Prices

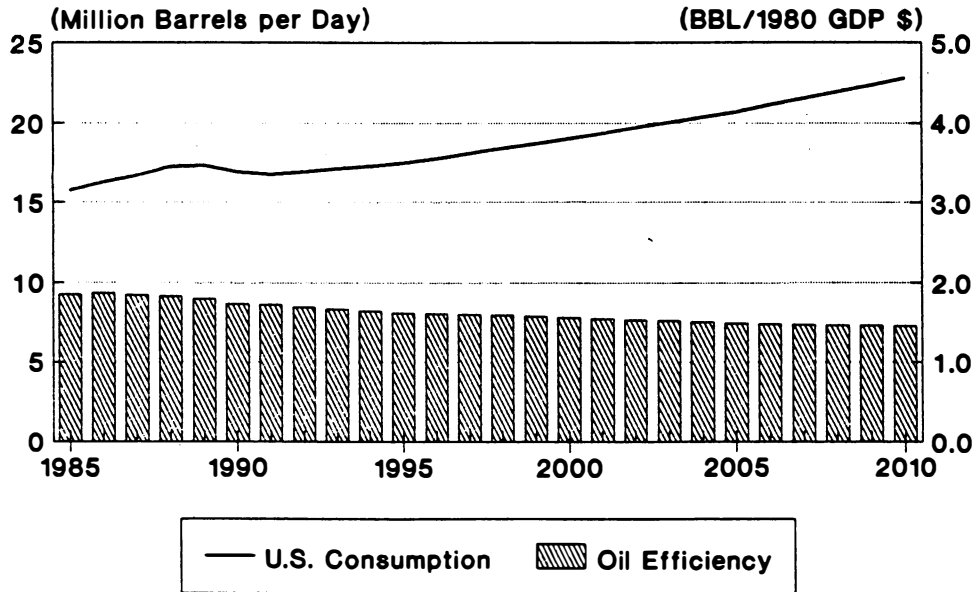
LONG-TERM OUTLOOK: Sustained Upward Pressure on Crude Prices

- **Certain OPEC Producers Experience Flat or Declining Production, and Require Higher Real Prices**
- **Non-OPEC Oil Production and Net CPE Exports Begin Protracted Decline**
- **OPEC Production Capacity Expands to Meet Increased Requirements**
- **Real Crude Price Growth Moderates from 4% Annually in Early 1990s to 2% Long Term**
- **Real Crude Prices Rise From \$18.50 in 1991 to \$24 in 2000 and \$29 in 2010**

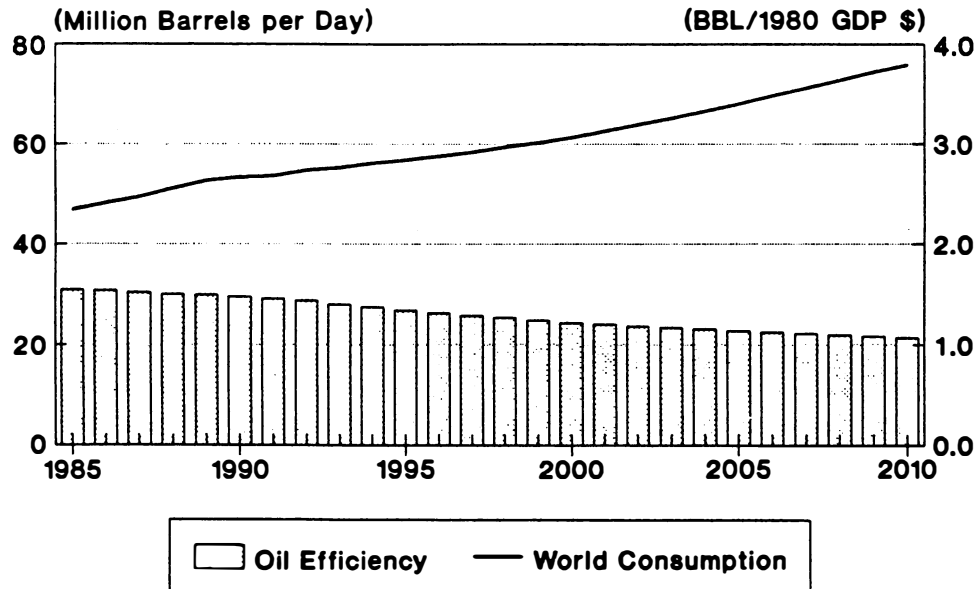
Slower Near-Term Economic Growth Yields to Faster Growth in Late 1990s

	(Average Annual Percent Change)		
	85-90	90-95	95-2000
	-----	-----	-----
United States	2.8	2.0	2.5
Canada	3.1	2.3	3.4
Japan	4.7	3.7	3.5
European Big 4	3.1	2.5	3.4
Other OECD	3.0	2.6	3.3
Non-OPEC LDCs	5.2	5.1	5.9
OPEC	2.6	5.3	5.0

U.S. Demand for Petroleum Will Grow Slowly, Then Accelerate

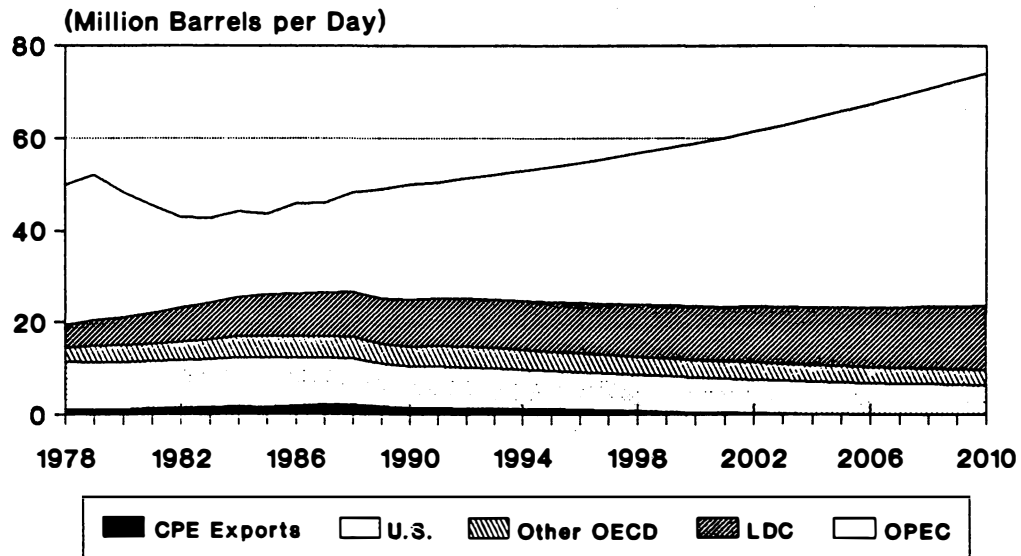


World Oil Demand* Will Exhibit Steady Growth

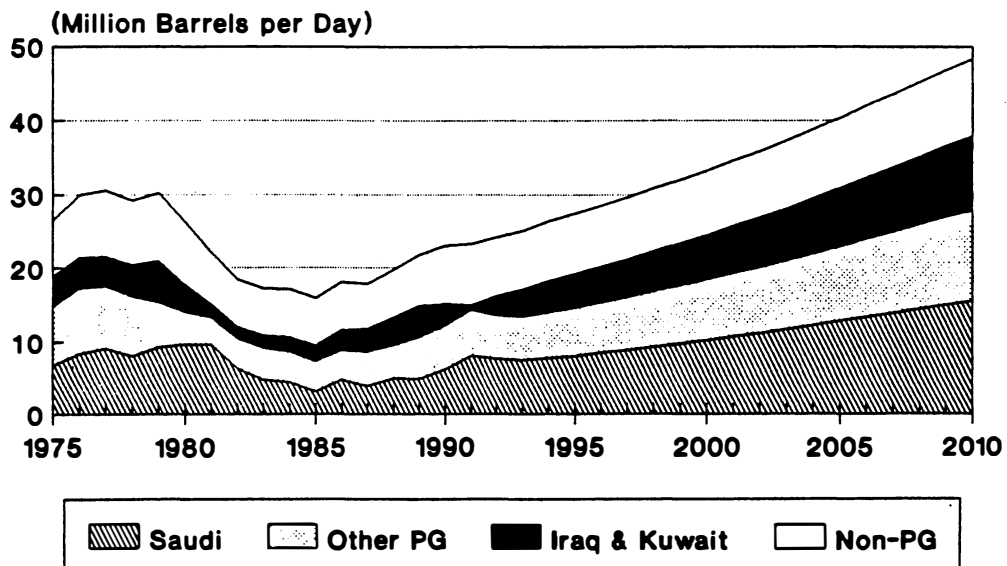


•(Not Including CPEs)

OPEC Will Gain From Declines in Non-OPEC and CPE Exports



The Persian Gulf Countries Will Expand Their Dominance over OPEC Production



Risks to the Forecast

Lower Prices Result From:

- **Low Economic Growth, Which Reduces Growth in Oil Consumption**
- **OPEC Discord on Production and Pricing**
- **Inability to Restrain Production Versus Sluggish Oil Demand Causes Sharper Price Decline Than Base Case**

Higher Prices Caused by:

- **Stronger Economic Recovery and Faster Oil Demand Demand Growth Than Base Case**
- **Kuwaiti and Iraqi Outages Are Longer Than Expected**
- **Saudi-Led OPEC Achieves Successful Production Restraint**

World Oil Outlook Summary (Million Barrels per Day)

	YEARS								%CH	%CH	%CH	%CH	%CH
	1989	1990	1991	1992	1995	2000	2005	2010	89 TO 90	90 TO 95	95 TO 2000	2000 TO 2005	2005 TO 2010
OIL CONSUMPTION													
MAJOR SEVEN	31.93	31.83	31.76	32.30	33.10	35.48	39.40	43.88	-0.3	0.8	1.4	2.1	2.2
OTHER OECD	5.67	5.87	6.02	6.28	6.38	6.77	7.53	8.41	3.6	1.7	1.2	2.1	2.3
TOTAL OECD	37.60	37.70	37.78	38.58	39.49	42.25	46.93	52.29	0.3	0.9	1.4	2.1	2.2
DEVELOPING AREAS	14.91	15.52	15.70	16.01	17.19	18.98	21.05	23.59	4.1	2.1	2.0	2.1	2.3
NON-COMMUNIST CONSUMPTION	52.50	53.22	53.48	54.59	56.68	61.23	67.98	75.88	1.4	1.3	1.6	2.1	2.2
OIL PRODUCTION													
MAJOR SEVEN	13.38	13.07	13.32	13.30	12.36	11.30	10.40	9.59	-2.4	-1.1	-1.8	-1.7	-1.6
OTHER NON-OPEC	11.77	12.26	12.55	12.62	12.67	13.13	13.95	14.93	4.2	0.7	0.7	1.2	1.4
TOTAL NON-OPEC	25.15	25.32	25.88	25.92	25.03	24.43	24.35	24.52	0.7	-0.2	-0.5	-0.1	0.1
OPEC CRUDE	21.77	23.00	23.27	24.15	27.43	33.27	40.41	48.32	5.7	3.6	3.9	4.0	3.6
OPEC NGLs	1.91	1.90	1.87	1.89	1.95	2.02	2.12	2.23	-0.2	0.5	0.7	1.0	1.0
TOTAL OPEC PRODUCTION	23.67	24.91	25.14	26.04	29.38	35.29	42.53	50.55	5.2	3.4	3.7	3.8	3.5
NON-COMMUNIST PRODUCTION	48.82	50.23	51.02	51.96	54.41	59.72	66.88	75.07	2.9	1.6	1.9	2.3	2.3
NET COMMUNIST EXPORTS	1.84	1.58	1.50	1.43	1.23	0.47	-0.04	-0.54	-14.1	-4.9	-17.5	NM	-70.8
REFINERY GAIN	1.10	1.12	1.12	1.15	1.19	1.29	1.43	1.59	1.4	1.3	1.6	2.1	2.2
INVENTORY WITHDRAWALS (*)	0.74	0.29	-0.15	0.06	-0.15	-0.24	-0.29	-0.24	-60.4	NM	-10.6	-3.5	3.9
TOTAL NON-COMMUNIST SUPPLY	52.50	53.22	53.48	54.59	56.68	61.23	67.98	75.88	1.4	1.3	1.6	2.1	2.2
AVERAGE U.S. REFINERS' COST OF FOREIGN CRUDE													
1990 \$/BARREL	18.77	22.15	18.50	19.38	22.00	24.00	26.38	29.00	18.0	-0.1	1.8	1.9	1.9
CURRENT \$/BARREL	18.04	22.15	19.07	20.57	25.62	33.58	45.52	62.23	22.8	3.0	5.6	6.3	6.5

* Negative values indicate an inventory build;
includes statistical discrepancy.

World Crude Production Summary (Million Barrels per Day)

	YEARS								%CH	%CH	%CH	%CH	%CH
	1989	1990	1991	1992	1995	2000	2005	2010	89 TO 90	90 TO 95	95 TO 2000	2000 TO 2005	2005 TO 2010
UNITED STATES	7.68	7.37	7.36	7.25	6.72	5.99	5.36	4.76	-4.1	-1.8	-2.3	-2.2	-2.3
CANADA	1.56	1.53	1.52	1.47	1.39	1.44	1.51	1.56	-2.1	-1.8	0.6	1.1	0.6
JAPAN	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0	0.1	-0.5	-0.5	-0.1
UNITED KINGDOM	1.79	1.83	2.03	2.16	1.81	1.44	1.11	0.87	2.2	-0.1	-4.4	-5.1	-4.7
W. GERMANY	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.0	-0.7	-1.4	-0.6	-0.7
FRANCE	0.07	0.07	0.07	0.07	0.07	0.06	0.06	0.05	-0.6	-0.9	-1.4	-2.1	-1.8
ITALY	0.11	0.12	0.12	0.12	0.12	0.11	0.09	0.09	8.4	0.0	-1.8	-2.2	-1.3
MAJOR SEVEN	11.25	10.93	11.19	11.17	10.20	9.12	8.22	7.41	-2.8	-1.4	-2.2	-2.1	-2.0
SAUDI ARABIA	4.95	6.29	8.12	7.64	8.07	10.13	12.75	15.55	27.1	5.1	4.6	4.7	4.1
IRAN	2.86	3.09	3.23	3.05	3.42	4.47	5.60	6.76	7.9	2.1	5.5	4.6	3.8
IRAQ	2.82	2.01	0.50	1.83	3.13	4.18	5.25	6.40	-28.7	9.3	5.9	4.7	4.0
KUWAIT	1.60	1.08	0.18	0.89	1.61	2.02	2.91	3.77	-32.7	8.4	4.6	7.5	5.4
UNITED ARAB EMIRATES	1.88	2.06	2.36	2.17	2.23	2.76	3.40	4.37	9.7	1.6	4.4	4.2	5.2
QATAR	0.39	0.39	0.40	0.39	0.42	0.46	0.52	0.57	-1.6	1.8	1.8	2.5	1.9
NEUTRAL ZONE	0.40	0.29	0.19	0.28	0.36	0.44	0.50	0.55	-27.9	4.5	4.1	2.6	1.9
NIGERIA	1.64	1.78	1.83	1.74	1.81	1.86	1.75	1.76	8.7	0.3	0.5	-1.2	0.1
LIBYA	1.10	1.35	1.43	1.35	1.45	1.47	1.56	1.64	23.2	1.4	0.3	1.2	1.0
ALGERIA	0.70	0.77	0.76	0.73	0.72	0.80	0.73	0.65	10.1	-1.2	2.1	-1.8	-2.3
GABON	0.22	0.28	0.29	0.30	0.32	0.32	0.36	0.41	26.3	2.9	0.0	2.4	2.6
VENEZUELA	1.71	2.10	2.30	2.18	2.28	2.76	3.61	4.32	22.5	1.7	3.9	5.5	3.7
INDONESIA	1.22	1.25	1.40	1.32	1.30	1.31	1.15	1.23	2.6	0.8	0.2	-2.6	1.4
ECUADOR	0.29	0.29	0.29	0.29	0.30	0.29	0.33	0.33	-0.6	1.0	-0.7	2.6	0.0
OPEC	21.77	23.00	23.27	24.15	27.43	33.27	40.41	48.32	5.7	3.6	3.9	4.0	3.6
MEXICO	2.51	2.55	2.54	2.51	2.59	2.88	3.26	3.66	1.6	0.3	2.2	2.5	2.4
NORWAY	1.49	1.65	1.84	1.81	1.57	1.11	0.90	0.75	10.6	-1.1	-6.6	-4.1	-3.6
OTHER	7.07	7.31	7.49	7.61	7.81	8.38	8.95	9.62	3.4	1.3	1.4	1.3	1.4
OTHER NON-OPEC	11.07	11.50	11.87	11.94	11.97	12.37	13.11	14.03	4.0	0.8	0.7	1.2	1.4
NON-COMMUNIST WORLD	44.08	45.44	46.34	47.26	49.60	54.76	61.74	69.76	3.1	1.8	2.0	2.4	2.5
COMMUNIST WORLD	14.57	13.84	13.45	13.41	13.29	12.62	12.20	11.79	-5.0	-0.8	-1.0	-0.7	-0.7
TOTAL WORLD	58.64	59.67	59.78	60.66	62.89	67.38	73.94	81.55	1.8	1.1	1.4	1.9	2.0

THE ECONOMIC OUTLOOK

CASE 2

* * * * *

The Low-Reference Case

Prepared for
The National Petroleum Council
June 1992

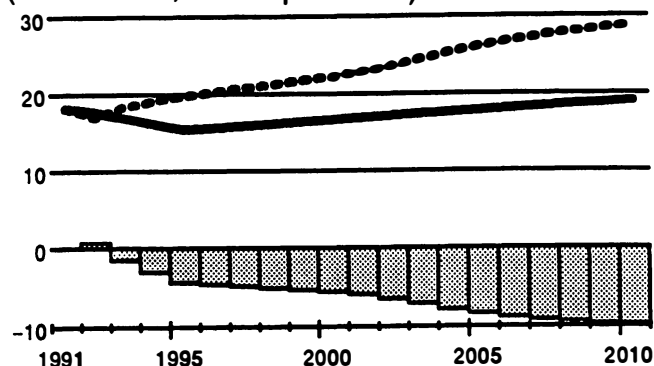
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Prepared by
Christopher Probyn
DRI/McGraw-Hill

A Comparison of NPC and DRI Forecasts

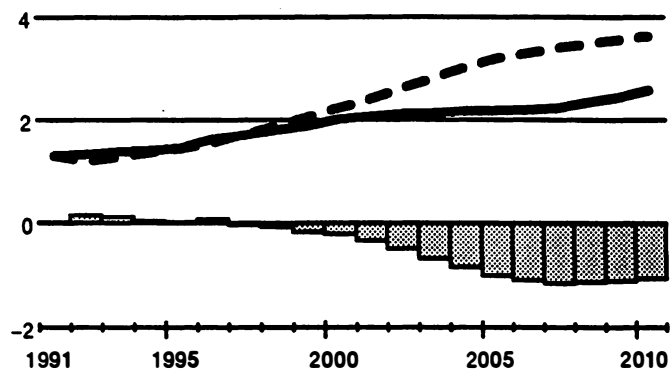
Refiners' Acquisition Price of Foreign Crude Oil

(1990 dollars, dollars per barrel)



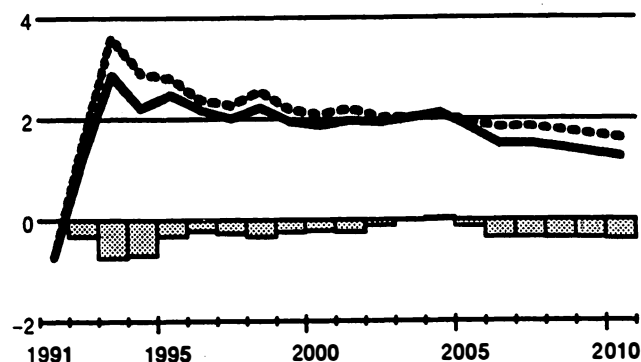
Tx/Gulf Spot Wellhead Price of Natural Gas

(1990 dollars per mmbtu)



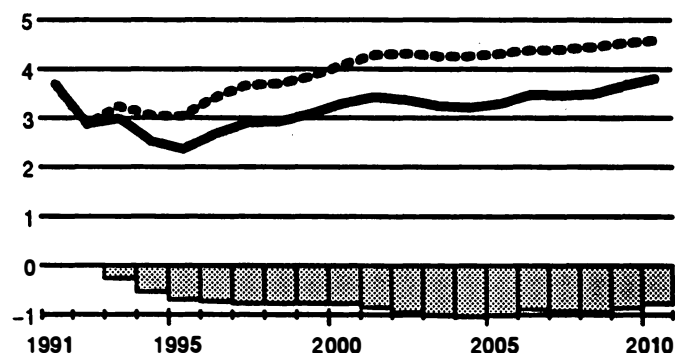
Real GNP

(Percent change)



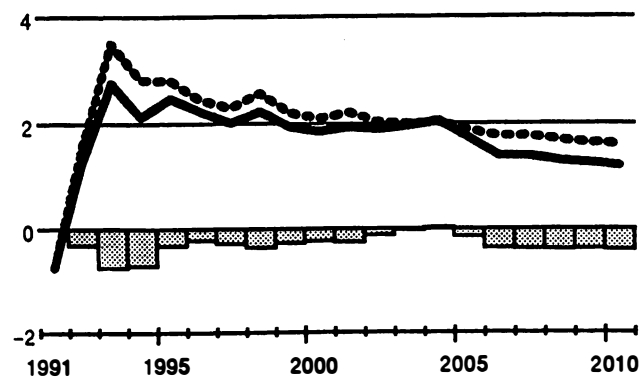
Implicit GNP Deflator

(Percent change)



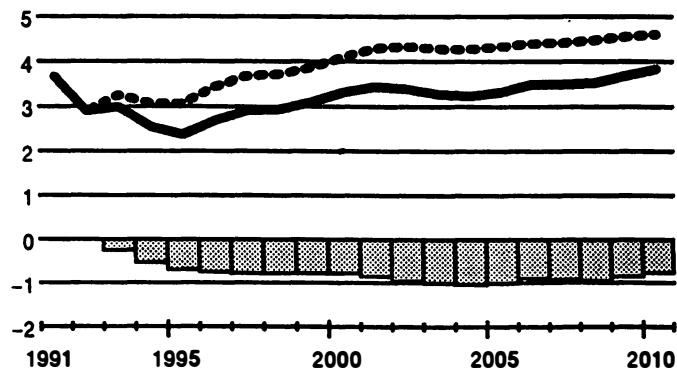
Real GDP

(Percent change)



Implicit GDP Deflator

(Percent change)



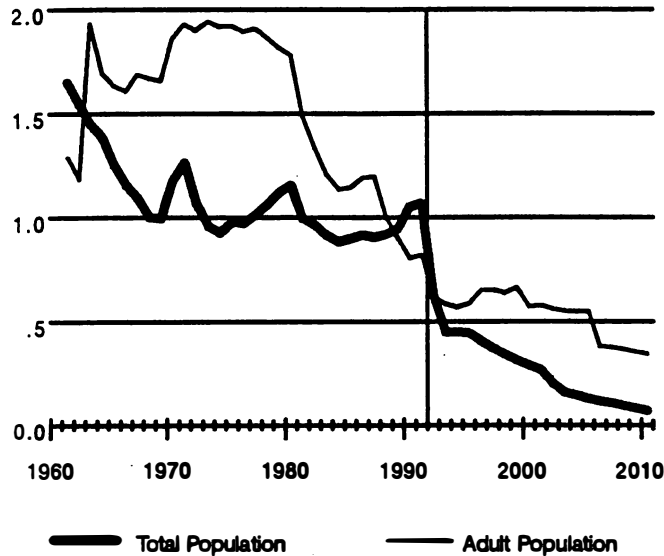
— NPC

... DRI

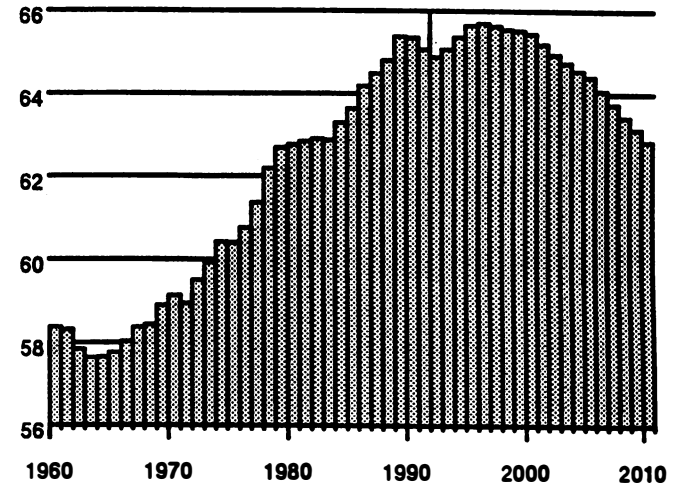
▨ Difference

NPC Forecast—A Graphic Summary

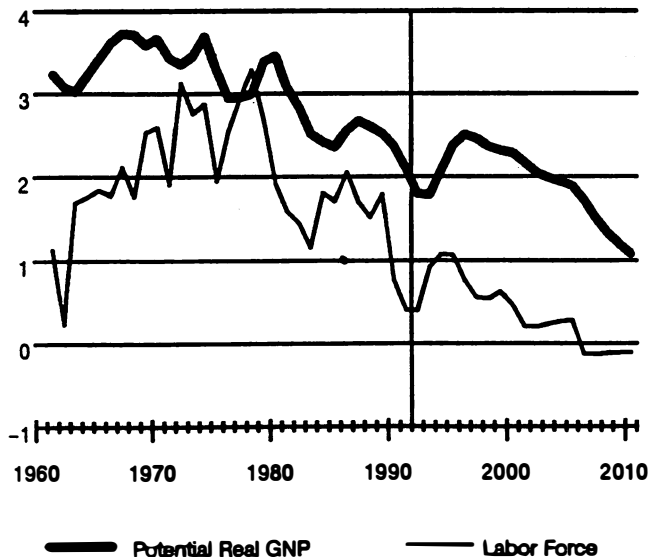
Population Growth Slows
(Percent change)



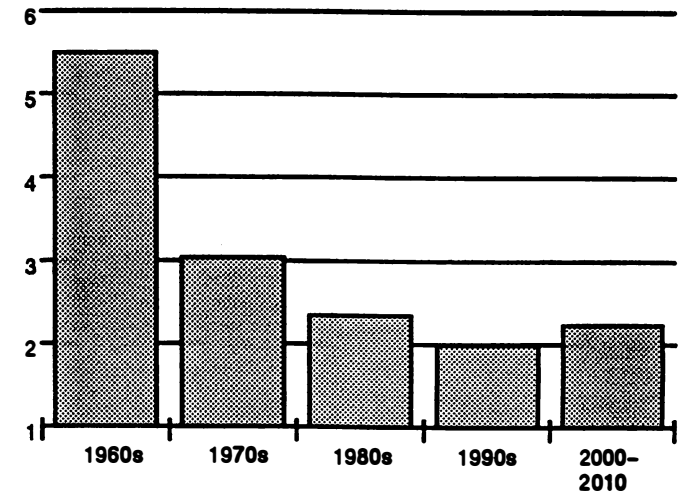
The Labor-Force Participation Rate Drops Off
(Percent)



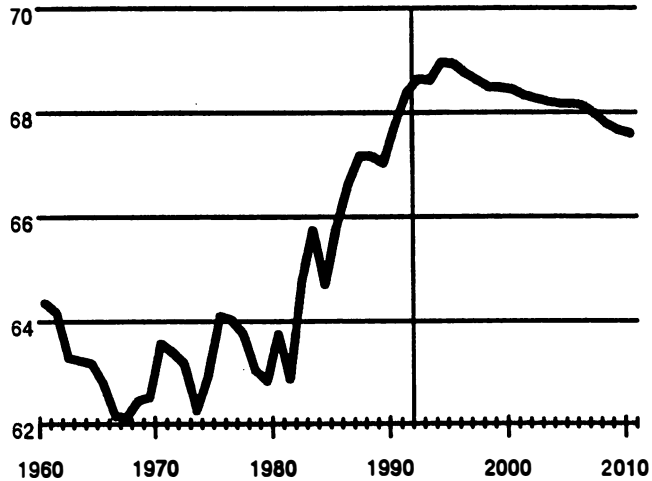
Slower Growth in the Labor Force Limits Gains in Potential Output
(Percent change)



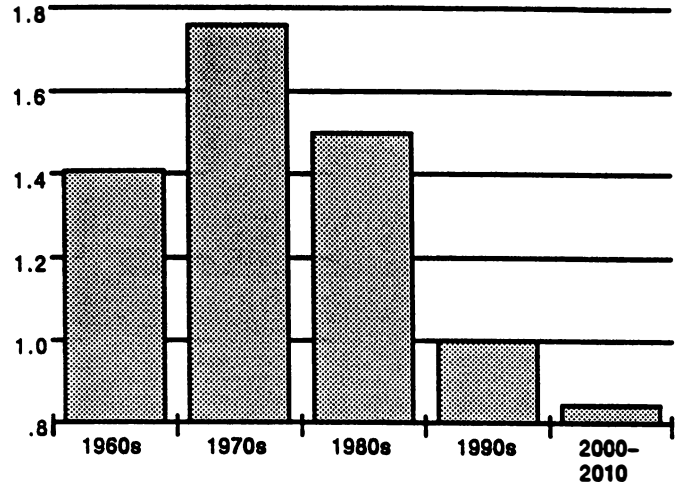
Industrial Production Growth Remains Slow
(Average annual percent change)



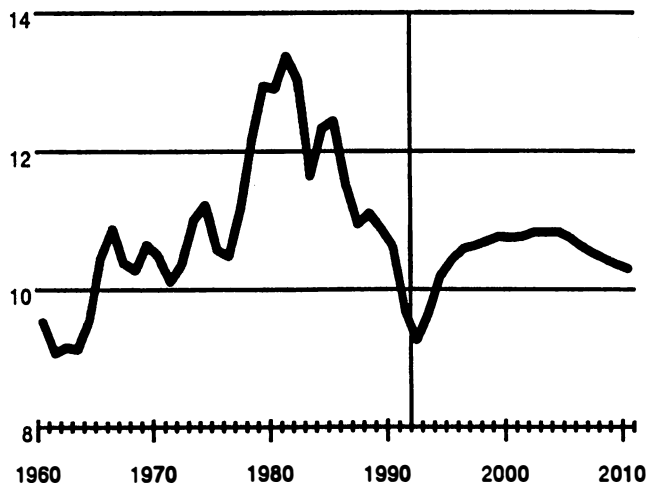
Consumption Retreats Slightly
(Percent of GNP)



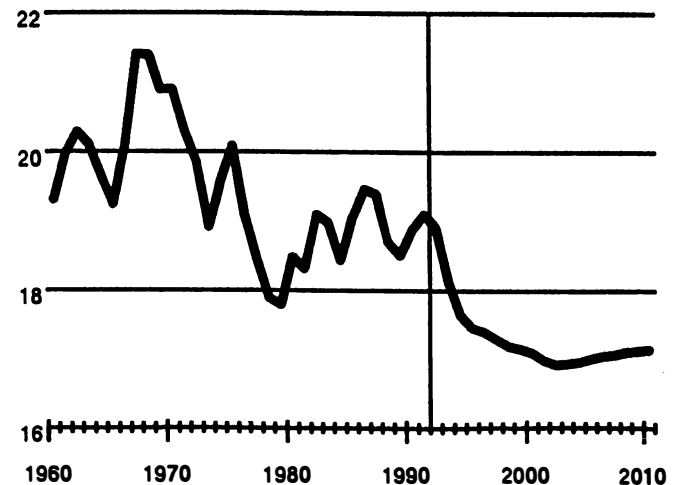
Housing Starts Tumble from 1970s Peak
(Average annual rate, millions of units)



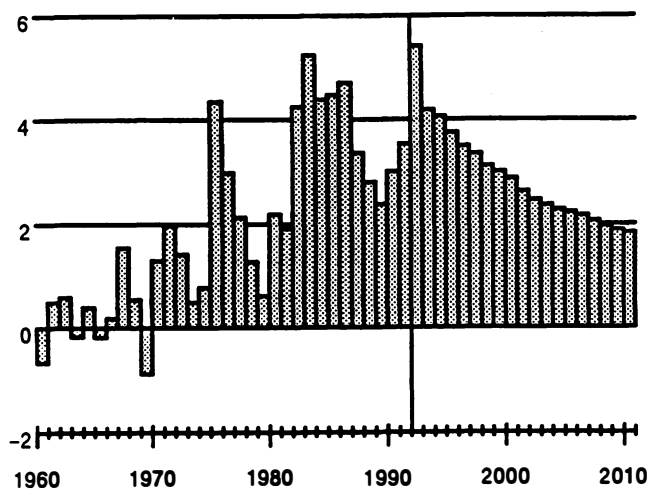
Business Fixed Investment Surges Back in the Near Term
(Percent of GNP)



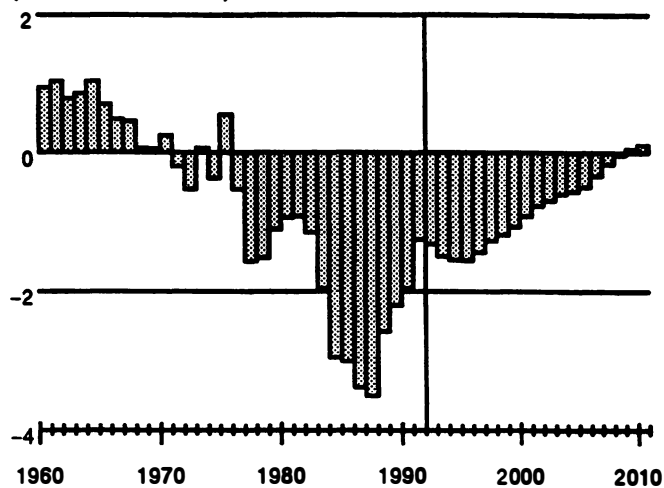
...As Government Spending Recedes
(Percent of GNP)



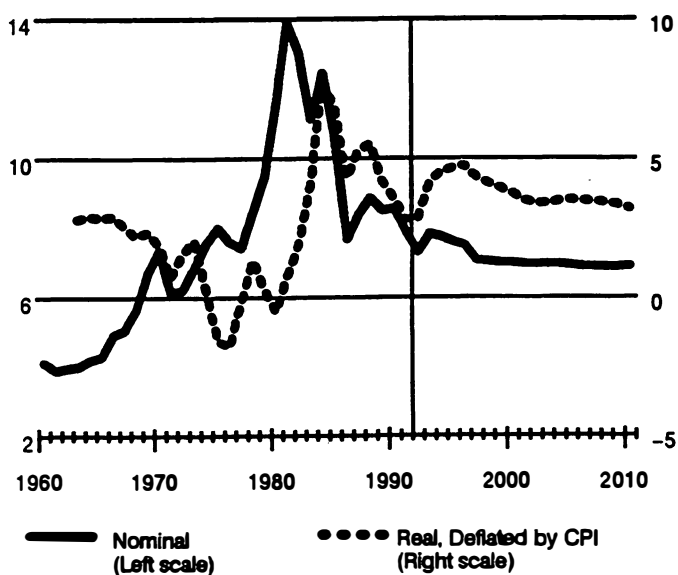
The Federal Deficit Improves Steadily
(Percent of GNP)



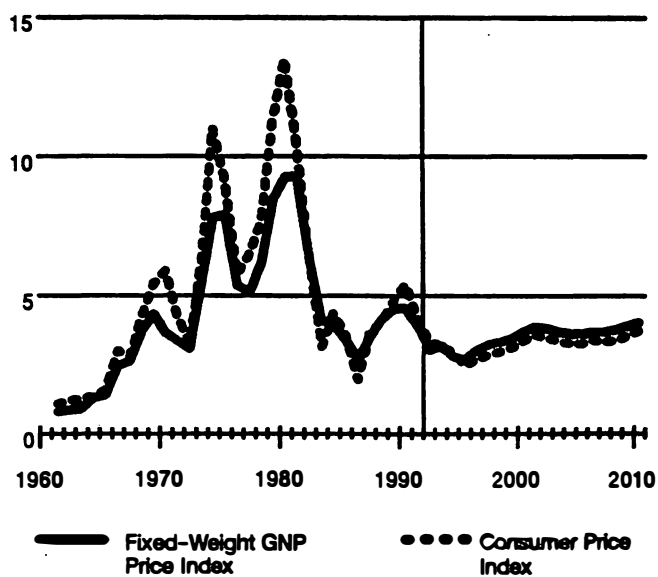
The Merchandise Trade Deficit Steadily Improves
(Percent of GNP)



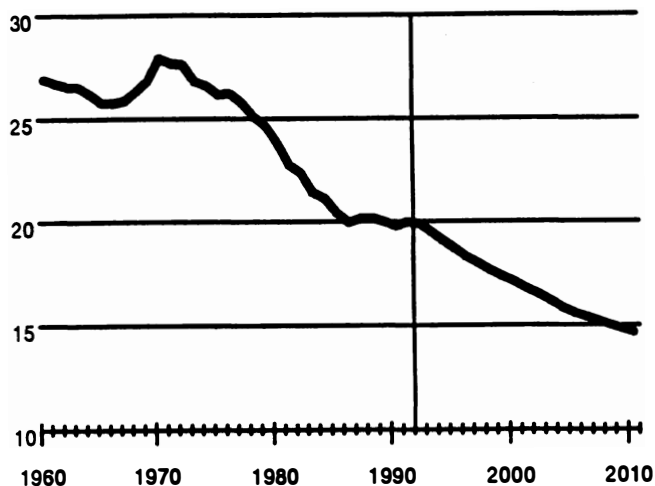
Real Interest Rates Moderate, But Remain High Relative to History
(Ten-year bond yield, percent)



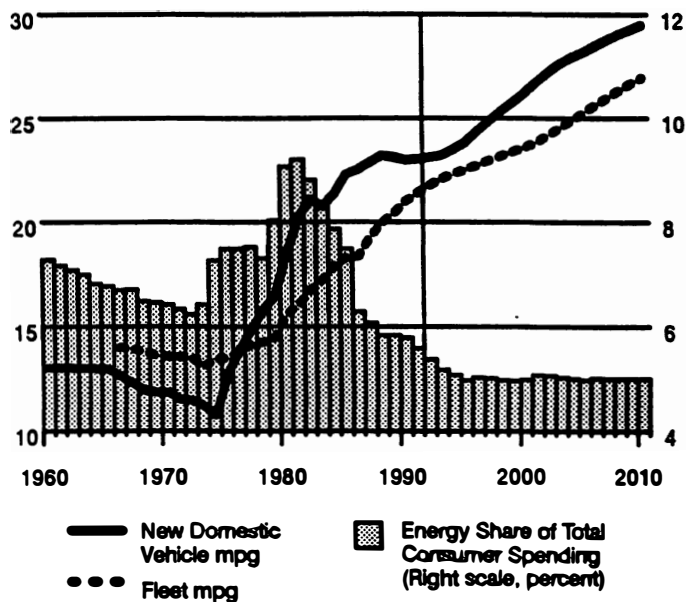
Inflation Remains Moderate
(Percent change)



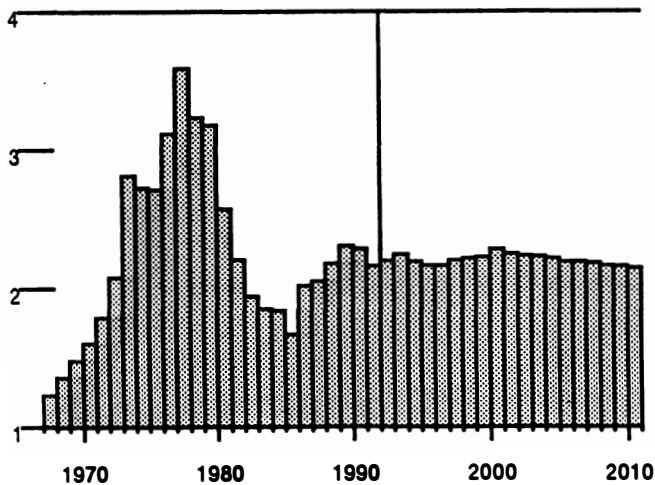
The Energy-to-GNP Ratio Keeps Falling
(Thousands of Btus per 1982 dollar of GNP)



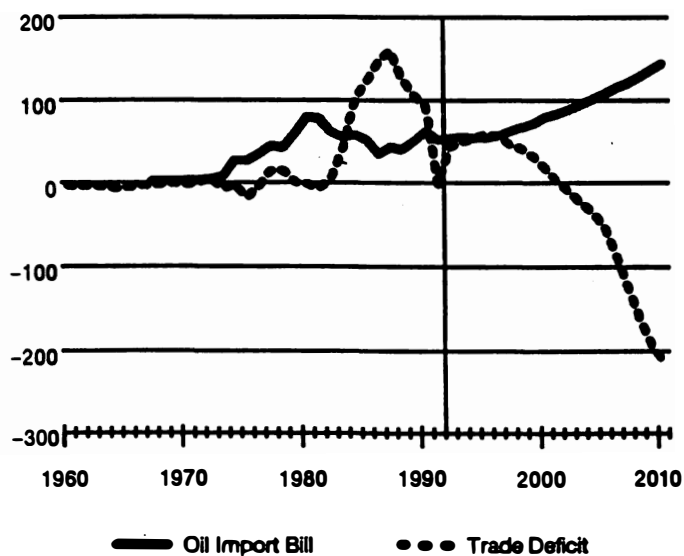
Consumers Continue to Spend Proportionately Less on Energy



Oil Import Volume Relative to Real GNP Remains Stable
(Percent)



The Oil Import Bill Exceeds the Trade Deficit in the Late 1990s
(Billions of dollars)



NPC Forecast

DRI/McGraw-Hill Summary Table for the U.S. Economy

	YEARS							Average Annual Compound Growth			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
	Composition of Real GNP (Annual rate of change)										
Gross Domestic Product	1.0	-0.6	1.4	2.8	2.1	1.9	1.3	1.7	2.4	2.2	1.4
Gross National Product	1.1	-0.6	1.3	2.8	2.1	2.0	1.3	1.8	2.3	2.3	1.5
Final Sales	1.8	-0.2	1.1	2.8	2.2	2.1	1.3	1.7	2.4	2.3	1.5
Excluding CCC Transactions	1.9	-0.3	1.1	2.8	2.2	2.1	1.3	1.7	2.4	2.3	1.5
Total Consumption	1.1	-0.3	1.3	2.2	1.6	1.7	1.1	1.6	1.7	1.7	1.1
Nonresidential Fixed Investment	1.7	-4.6	3.3	6.8	3.6	2.1	1.2	5.2	4.4	3.7	1.2
Equipment	2.7	-0.9	8.1	6.3	4.0	2.1	1.2	7.4	4.7	4.2	1.2
Structures	-0.5	-13.4	-9.6	8.6	1.8	1.8	1.3	-0.7	3.4	2.0	1.4
Residential Fixed Investment	-8.7	-10.4	6.1	5.8	0.9	0.5	1.8	-0.2	1.7	0.2	1.0
Exports	6.5	4.9	3.6	6.0	6.2	4.3	2.6	5.5	6.4	5.5	3.3
Imports	1.5	-0.5	5.7	4.8	4.0	2.8	1.8	5.3	4.0	3.9	1.7
Federal Government	1.5	1.1	-0.9	-4.0	-0.8	1.3	0.8	-3.4	-1.6	0.4	1.0
Excluding CCC Transactions	1.9	0.6	-0.8	-4.0	-0.8	1.3	0.8	-3.4	-1.6	0.4	1.0
State and Local Governments	4.5	0.7	0.7	3.0	1.0	1.0	0.4	1.7	1.5	0.8	0.5
Billions of Dollars											
Real GNP (1982 \$)	4,121.8	4,097.5	4,152.1	4,499.7	5,051.7	5,652.5	6,099.1	1.8	2.3	2.3	1.5
Gross National Product	5,524.6	5,684.7	5,922.0	6,893.0	8,824.5	11,443.3	14,617.6	4.5	5.1	5.3	5.0
Prices and Wages (Annual rate of change)											
GNP Price Deflator (Implicit)	4.1	3.5	2.8	2.1	3.0	3.1	3.7	2.7	2.7	3.0	3.4
GNP Price Index (Fixed-Weight)	4.6	3.9	3.0	2.7	3.7	3.6	4.1	3.1	3.3	3.7	3.8
CPI—All Urban Consumers	5.4	4.2	3.3	2.5	3.4	3.3	3.8	3.2	3.0	3.4	3.5
Producer Price Index—Finished Goods	4.9	2.1	2.1	1.5	3.1	2.8	3.6	1.9	2.6	2.9	3.2
Employment Cost Index—Total Comp.	5.0	4.4	3.8	4.1	4.9	4.8	5.0	3.9	4.7	5.0	4.9
Output per Hour	0.0	0.3	1.8	1.9	2.1	1.7	1.4	1.6	2.1	2.1	1.6
Production and Other Key Measures											
Industrial Production (1987=1.000)	1.092	1.071	1.088	1.182	1.352	1.548	1.677	1.6	2.7	2.7	1.6
Annual Rate of Change	1.0	-1.9	1.6	2.8	2.7	2.2	1.5	1.6	2.7	2.7	1.6
Nonfarm Inven Accum (Billion 1982 \$)	-0.7	-14.0	-5.3	17.0	16.9	24.6	27.4	NM	-0.2	7.8	2.2
Housing Starts (Mil units)	1.203	1.011	1.048	0.976	0.953	0.792	0.834	-4.1	-0.5	-3.6	1.1
Retail Unit Car Sales (Mil units)	9.5	8.4	8.7	10.1	10.3	10.7	10.4	1.1	0.5	0.8	-0.7
Civilian Unemployment Rate (%)	5.5	6.8	7.1	6.2	6.3	5.9	5.7	2.3	0.2	-1.2	-0.7
Nonfarm Empl. (Estab. survey, % change)	1.5	-0.9	0.2	1.4	0.4	0.4	0.1	0.7	0.6	0.4	0.0
Fed. Budget Surplus (Unified, FY, bil. \$)	-220.5	-268.7	-395.7	-250.5	-245.8	-281.5	-353.3	-2.6	0.4	-2.7	-4.6
Foreign Trade											
Current Account Balance (Billion \$)	-92.128	1.564	-43.697	-58.846	-17.502	51.474	212.074	8.6	21.5	NM	32.7
Merch. Trade Balance (c.v.b., bil. \$)	-101.7	-62.7	-67.5	-94.9	-64.2	-34.7	44.8	1.4	7.5	11.6	NM
Foreign Crude Oil (\$ per barrel)	22.22	18.83	18.79	17.73	22.20	27.97	35.57	-4.4	4.6	4.7	4.9
U.S. Dollar Exchange Rate (% change)	-5.2	-1.1	0.7	-0.6	-0.7	-0.5	0.0	0.3	-0.7	-0.6	-0.2
Foreign GDP (% change)	3.0	2.2	2.0	3.5	3.4	3.2	2.7	2.8	3.4	3.3	2.9
Financial Markets											
Money Supply (M2, billion \$)	3,325.3	3,416.0	3,580.9	4,135.4	5,465.1	7,103.3	8,943.5	4.5	5.7	5.4	4.7
Percent Change vs Year Ago (Q4/Q4)	3.8	2.7	4.8	5.1	5.8	5.2	4.8	4.5	5.7	5.4	4.7
AA Corp Utility Rate (%)	9.66	9.10	8.72	8.98	8.47	8.42	8.30	-1.4	-1.2	-0.1	-0.3
Thirty-Year Treasury Bond Rate (%)	8.61	8.14	7.67	7.75	7.05	6.96	6.93	-2.1	-1.9	-0.3	-0.1
Treasury Bill Rate (%)	7.49	5.38	3.87	6.10	5.58	5.62	5.61	-4.0	-1.8	0.1	0.0
Federal Funds Rate (%)	8.10	5.69	3.86	6.64	6.00	6.00	5.99	-3.9	-2.0	0.0	0.0
Prime Rate (%)	10.01	8.46	6.35	8.64	7.50	7.50	7.49	-2.9	-2.8	0.0	0.0
S&P Index of 500 Common Stocks	335	376	417	472	647	849	1,146	7.1	6.5	5.6	6.2
Incomes											
Personal Income (Billion \$)	4,679.8	4,833.9	5,046.6	5,947.8	7,586.0	9,828.2	12,523.1	4.9	5.0	5.3	5.0
Real Disposable Income (% change)	1.8	-0.2	1.1	2.3	1.5	1.8	1.1	1.6	1.6	1.7	1.1
Saving Rate (%)	5.1	5.3	5.2	5.4	5.4	5.5	5.6	1.0	0.0	0.5	0.3
Profits After Tax (Billion \$)	197.0	187.8	209.6	264.8	349.3	415.4	589.1	6.1	5.7	3.5	7.2
Post-Tax Corp Cash Flow (Billion \$)	549.1	566.5	638.6	741.4	967.7	1,225.5	1,600.6	6.2	5.5	4.8	5.5
Percent Change vs Year Ago	-2.7	3.2	12.7	5.6	5.2	4.0	5.5	6.2	5.5	4.8	5.5

NPC Forecast

U.S. Energy Outlook Summary

	YEARS							Average Annual Compound Growth			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Demand for All Fuels											
Total Energy Demand (Quad Btus)	81.4	81.8	82.4	84.0	86.1	87.9	89.4	0.6	0.5	0.4	0.3
Annual Rate of Change	0.1	0.5	0.8	0.6	0.6	0.4	0.3	0.6	0.5	0.4	0.3
Real GNP (% change)	1.1	-0.6	1.3	2.8	2.1	2.0	1.3	1.8	2.3	2.3	1.5
Energy Use Ratios											
Million Btus per Capita	325.6	323.6	324.1	325.8	328.3	332.4	336.3	0.0	0.2	0.2	0.2
Thousand Btus per 1982 \$ GNP	19.8	20.0	19.9	18.7	17.0	15.6	14.7	-1.1	-1.8	-1.8	-1.2
Prices (Dollars per barrel)											
U.S. Refiners' Acquisition Price for Crude Oil—Composite	22.35	19.14	18.71	17.61	22.08	27.83	35.42	-4.6	4.6	4.7	4.9
Annual Rate of Change	24.4	-14.4	-2.2	-2.2	5.0	4.8	5.2	-4.6	4.6	4.7	4.9
Domestic	22.44	19.37	18.65	17.50	21.92	27.62	35.12	-4.8	4.6	4.7	4.9
Annual Rate of Change	25.5	-13.7	-3.7	-2.2	5.0	4.8	5.2	-4.8	4.6	4.7	4.9
Foreign	22.22	18.83	18.79	17.73	22.20	27.97	35.57	-4.4	4.6	4.7	4.9
Annual Rate of Change	23.0	-15.3	-0.2	-2.2	5.0	4.8	5.2	-4.4	4.6	4.7	4.9
Foreign (1990 \$)	22.22	18.19	17.66	15.51	17.03	18.52	19.89	-6.9	1.9	1.7	1.4
Annual Rate of Change	18.1	-18.1	-2.9	-4.1	2.0	1.6	1.5	-6.9	1.9	1.7	1.4
Prices (Percent change)											
Producer Price Index—Fuel and Power	12.8	-1.3	-0.9	-0.5	6.1	4.6	5.3	-0.4	4.2	5.1	5.0
Coal	2.1	-0.3	1.6	2.0	4.2	4.5	4.7	1.7	3.8	4.4	4.6
Natural Gas	4.1	-1.9	3.6	-2.8	11.2	6.0	7.0	-1.0	5.1	7.9	6.5
Electricity	2.5	5.7	1.4	0.2	4.4	3.6	4.3	1.4	2.0	3.7	4.1
Domestic Crude Oil (NSA)	26.1	-12.7	-4.6	-2.3	5.0	4.7	5.2	-4.8	4.6	4.7	4.9
Refined Petroleum Products	22.3	-10.4	-1.0	0.5	5.5	4.3	4.8	-1.5	4.9	4.7	4.6
Residual Fuels	21.4	-18.9	-1.4	-1.4	5.5	5.0	5.4	-3.6	5.0	5.2	5.2
Producer Price Index—Industrial	3.8	0.6	0.7	1.2	3.3	3.0	3.8	1.0	2.8	3.2	3.5
Personal Consump Deflator—Energy	8.6	0.8	0.8	1.6	5.1	4.2	4.9	1.0	4.2	4.6	4.8
Gasoline	14.0	-1.5	-1.0	2.9	5.4	4.3	4.8	0.6	5.9	5.2	5.0
Fuel Oil and Coal	20.4	-3.7	-0.4	0.4	3.7	3.8	3.8	0.2	2.9	3.9	3.8
Electricity	2.4	3.8	2.3	0.6	4.6	4.0	5.0	1.4	2.0	3.8	4.6
Natural Gas	0.1	1.3	3.0	-0.1	5.5	4.0	5.4	0.9	3.9	4.6	4.9
Personal Consumption Deflator	5.3	4.2	3.3	2.6	3.5	3.4	3.8	3.2	3.2	3.5	3.7
Gasoline Tax (Cents per gallon)	25.7	31.7	32.7	36.2	47.8	62.3	80.1	7.1	5.7	5.4	5.2
Federal	10.5	15.1	15.1	15.1	20.1	25.1	30.1	7.5	5.9	4.5	3.7
State and Local	15.2	16.6	17.6	21.1	27.8	37.2	50.0	6.8	5.6	6.1	6.1

U.S. Energy Outlook Summary (Continued)

	YEARS										
	1990	1991	1992	1995	2000	2005	2010	1990	1995	2000	2005
Household Energy Consumption	-2.9	-0.6	-0.2	1.3	0.7	0.6	0.1	0.8	0.8	0.6	0.1
Gasoline	-1.9	-2.3	-1.5	0.8	0.4	0.1	-0.4	-0.1	0.4	0.1	-0.4
Fuel Oil and Coal	-13.0	-3.9	1.8	0.7	-0.4	-0.1	-0.7	0.1	-0.3	-0.1	-0.7
Electricity	0.4	3.3	-0.3	2.6	1.9	1.7	1.1	2.3	2.0	1.7	1.3
Natural Gas	-8.0	-0.6	4.1	0.3	-0.5	-0.3	-0.8	1.2	-0.1	-0.4	-0.8
Total Consumption	1.1	-0.3	1.3	2.2	1.6	1.7	1.1	1.6	1.7	1.7	1.1
Energy Share of Consumption (%)											
1982 Dollars	7.6	7.6	7.4	7.3	6.9	6.6	6.2	-0.9	-0.9	-1.1	-1.0
Current Dollars	5.8	5.6	5.4	5.0	5.0	5.0	5.0	-3.0	0.1	-0.1	0.1
Average Miles per Gallon	21.0	21.4	21.8	22.5	23.6	25.2	27.0	1.4	0.9	1.4	1.3

Imports of Petroleum and Products

Billions of 1982 Dollars	94.1	88.4	91.2	97.3	115.3	123.9	131.0	0.7	3.5	1.5	1.1
Billions of Current Dollars	62.3	51.3	54.0	53.7	79.2	107.3	144.2	-2.9	8.1	6.3	6.1
Import Bill as Percent of GNP	1.13	0.90	0.91	0.78	0.90	0.94	0.99	-7.1	2.9	0.9	1.0

Industrial Production

Oil and Gas Extraction (% change)	0.0	0.3	-4.9	-0.3	1.2	-0.9	-0.4	-1.4	-0.5	-1.2	-0.9
Piped Gas and Electric Utilities (% change)	0.9	0.6	1.5	1.8	2.6	1.5	0.9	1.4	1.7	1.5	1.0
Total Production (% change)	1.0	-1.9	1.6	2.8	2.7	2.2	1.5	1.6	2.7	2.7	1.6
Elec Util Fuel Use, Percent from:											
Coal	55.5	54.6	55.1	54.7	53.5	56.1	58.5	-0.3	-0.4	1.0	0.8
Natural Gas	9.3	9.1	8.8	9.8	11.2	10.6	9.7	1.1	2.8	-1.1	-1.9
Petroleum Products	4.2	4.2	3.8	4.0	4.8	4.8	4.8	-1.1	3.7	-0.1	-0.1
Hydro, Nuclear, Solar, and Other	31.0	32.0	32.3	31.5	30.5	28.5	27.1	0.4	-0.7	-1.3	-1.0

Comparison of the NPC and DRI Forecasts

Key Economic Indicators (Compound average annual growth rates)

	NPC Forecast 1990-2010	DRI Forecast 1990-2010
Residential and Commercial Sectors		
Residential Building Stock	0.7	1.0
Commercial Floor Space	1.1	1.3
Disposable Income	1.5	1.8
Residential Population	0.3	0.6
Industrial Sector		
Food	1.4	1.6
Textiles	0.5	0.7
Paper	1.7	2.0
Chemicals	2.0	2.3
Petroleum Refining	-0.1	0.5
Stone, Clay & Glass	0.9	1.3
Iron and Steel	-0.5	-0.3
Nonferrous Metals	1.6	2.0
Other	2.2	2.8
Total Industrial	2.2	2.5
Real GNP	2.0	2.3
GNP Deflator	2.9	3.7

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Version: NPC LOWREF CASE
OUTLOOK FOR THE U.S. ENERGY SECTOR

	YEARS									%CH ----- 91 TO 92	%CH ----- 90 TO 2000	%CH ----- 2000 TO 2010
	1990	1991	1992	1993	1994	1995	2000	2005	2010			
PRIMARY ENERGY CONSUMPTION BY SECTOR (QUADRILLION BTU)												
Total	80.6	80.3	81.9	82.9	83.5	84.6	87.1	89.7	90.0	2.0	0.8	0.3
Residential	5.9	6.1	6.2	6.3	6.2	6.2	6.1	6.0	5.8	3.1	0.3	-0.5
Commercial	3.8	3.8	3.9	4.0	4.0	4.0	4.2	4.4	4.6	3.6	1.0	1.1
Industrial	19.6	19.1	19.6	19.6	19.5	19.7	20.0	20.4	20.1	2.6	0.2	0.0
Transportation	21.7	21.4	22.0	22.2	22.5	22.9	23.8	24.8	24.6	2.6	0.9	0.3
Electric Utility	29.6	30.0	30.2	30.9	31.2	31.8	33.0	34.1	34.9	0.8	1.1	0.6
Energy to Real GNP	19.54	19.60	19.73	19.38	19.06	18.81	17.24	15.86	14.76	0.7	-1.2	-1.5
TOTAL CONSUMPTION BY FUEL TYPE (QUADRILLION BTU)												
Petroleum	33.6	32.8	32.7	33.1	33.3	34.1	35.4	36.5	37.1	-0.4	0.5	0.5
Natural Gas	19.3	19.7	20.0	20.1	20.2	20.2	21.8	23.2	23.1	1.5	1.2	0.6
Coal	19.0	18.8	19.1	19.3	19.4	19.6	18.7	18.5	18.2	1.7	-0.2	-0.3
Nuclear	6.2	6.6	6.9	6.9	7.0	7.1	7.4	7.4	7.4	4.3	1.8	0.0
Hydropower	2.9	3.1	3.2	3.2	3.3	3.3	3.4	3.7	3.9	1.9	1.6	1.2
Other	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.3	0.3	5.0	5.8	-3.3
Electricity	9.1	9.3	9.3	9.5	9.6	9.8	10.4	10.9	11.3	0.7	1.4	0.8
PRICES (CONSTANT 1991 DOLLARS PER MILLION BTU)												
Crude Oil (Imported)	3.88	3.25	3.16	3.03	2.90	2.79	3.05	3.32	3.59	-2.5	-2.4	1.6
Residual Fuel-Electric Utility	3.42	2.47	2.54	2.64	2.65	2.61	2.89	3.14	3.42	3.0	-1.7	1.7
Distillate-Residential	8.08	7.38	6.96	6.98	7.11	6.96	7.15	7.59	7.97	-5.7	-1.2	1.1
Gasoline-Retail	10.07	9.57	9.13	8.96	8.91	8.92	10.37	11.38	12.11	-4.6	0.3	1.6
Coal-Electric Utility	1.51	1.46	1.37	1.39	1.40	1.42	1.54	1.65	1.76	-6.0	0.2	1.4
Natural Gas-Wellhead Spot	1.58	1.34	1.30	1.34	1.34	1.47	1.78	1.99	2.55	-3.3	1.2	3.6
Natural Gas-Residential	5.82	5.59	5.43	5.46	5.45	5.58	5.91	6.13	6.74	-2.8	0.1	1.3
Natural Gas-Commercial	4.84	4.64	4.49	4.52	4.52	4.65	4.97	5.19	5.78	-3.3	0.3	1.5
Natural Gas-Industrial	2.94	2.82	2.69	2.73	2.74	2.87	3.20	3.38	4.02	-4.8	0.8	2.3
Natural Gas-Utility	2.39	2.21	2.07	2.12	2.14	2.27	2.58	2.81	3.39	-6.3	0.8	2.7
Electricity-Residential	23.72	22.84	22.52	22.21	21.85	21.70	21.52	22.23	23.15	-1.4	-1.0	0.7
Electricity-Commercial	21.74	21.21	20.93	20.54	20.09	19.84	19.64	20.45	21.48	-1.3	-1.0	0.9
Electricity-Industrial	14.67	14.38	14.16	14.09	14.04	14.05	14.47	15.09	15.99	-1.6	-0.1	1.0

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Version: NPC LOWREF CASE

	YEARS									%CH ----- 91 TO 92	%CH ----- 90 TO 2000	%CH ----- 2000 TO 2010
	1990	1991	1992	1993	1994	1995	2000	2005	2010			
FUEL CONSUMPTION BY SECTOR (QUADRILLION BTU)												
Residential												
Petroleum	1.3	1.3	1.4	1.4	1.4	1.4	1.3	1.3	1.2	1.8	0.0	-0.6
Natural Gas	4.5	4.7	4.8	4.8	4.8	4.8	4.7	4.6	4.5	3.5	0.4	-0.5
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.2	-0.1	-0.3
Electricity	3.1	3.3	3.3	3.4	3.4	3.5	3.7	4.0	4.2	1.0	1.8	1.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	0.5	0.5
Commercial												
Petroleum	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.8	0.8	3.4	-0.5	-0.5
Natural Gas	2.8	2.9	3.0	3.0	3.0	3.1	3.2	3.5	3.7	3.8	1.5	1.5
Coal	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	-0.2	-0.1	-0.3
Electricity	2.8	2.8	2.9	2.9	3.0	3.1	3.4	3.5	3.7	0.2	1.8	0.9
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2
Industrial												
Petroleum	8.3	7.9	8.1	8.1	8.1	8.3	8.9	9.2	9.4	2.7	0.7	0.6
Natural Gas	8.5	8.5	8.7	8.7	8.7	8.7	8.8	9.0	8.6	2.2	0.4	-0.2
Coal	2.8	2.6	2.7	2.7	2.7	2.7	2.3	2.2	2.1	3.8	-1.8	-1.2
Electricity	3.2	3.1	3.2	3.2	3.2	3.2	3.3	3.4	3.4	0.9	0.5	0.2
Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transportation												
Petroleum	21.7	21.4	21.3	21.5	21.8	22.2	22.9	23.6	23.4	-0.6	0.5	0.2
Natural Gas	0.7	0.8	0.7	0.6	0.6	0.7	0.9	1.1	1.2	-12.7	2.7	2.7
Electricity	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	-19.8	1.6	0.7
Electric Utility												
Petroleum	1.4	1.3	1.0	1.1	1.1	1.4	1.4	1.6	2.2	-19.9	0.1	4.9
Natural Gas	2.9	2.8	2.8	3.0	3.0	3.1	4.2	4.9	5.2	-2.2	3.9	2.2
Coal	16.1	16.0	16.2	16.4	16.6	16.8	16.2	16.2	16.0	1.3	0.1	-0.2
Nuclear	6.2	6.6	6.9	6.9	7.0	7.1	7.4	7.4	7.4	4.3	1.8	0.0
Hydropower	2.9	3.1	3.1	3.2	3.2	3.3	3.4	3.6	3.8	2.0	1.6	1.2
Other	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.3	0.3	5.0	5.9	-3.4
OTHER KEY MEASURES (ANNUAL RATES OF CHANGE)												
Real GNP	1.13	-0.59	1.33	2.99	2.40	2.76	2.14	2.02	1.34	1.3	2.1	1.9
GNP Deflator	4.10	3.51	2.80	2.85	2.32	2.07	3.01	3.10	3.69	2.8	2.7	3.2
Real Disposable Income	1.79	-0.25	1.08	2.18	2.91	2.26	1.49	1.82	1.08	1.1	1.6	1.4
FRB Production Index	1.02	-1.92	1.61	3.36	2.25	2.75	2.71	2.16	1.46	1.6	2.2	2.2
FRB Capacity Utilization	-1.97	-4.95	-0.35	1.43	-0.85	-0.18	-0.31	-0.26	0.53	-0.3	-0.7	0.1

U.S. Macroeconomic Source: (DRICHIP)NPCLOWREF

6/29/92

Version: NPC LOWREF CASE

RESIDENTIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal	72.7	73.2	73.0	72.9	72.8	72.6	71.8	70.8	69.7	-0.2	-0.1	-0.3
Natural Gas	4,526.7	4,658.1	4,822.0	4,797.6	4,789.0	4,771.1	4,701.1	4,630.7	4,468.6	3.5	0.4	-0.5
Petroleum	1,318.7	1,328.9	1,352.6	1,379.7	1,373.4	1,374.5	1,324.3	1,295.6	1,249.3	1.8	0.0	-0.6
Distillate Fuel	835.8	788.1	839.2	862.5	854.7	854.0	818.2	793.0	755.0	6.5	-0.2	-0.8
Liquefied Gases	423.1	449.3	433.9	436.9	437.4	438.3	427.6	426.9	421.3	-3.4	0.1	-0.1
Kerosene	59.8	91.5	79.5	80.3	81.3	82.2	78.5	75.6	73.1	-13.1	2.8	-0.7
Other	1.5	1.5	1.5	1.5	1.5	1.5	1.6	1.6	1.6	0.5	0.5	0.5
Total Direct Fuels	5,919.6	6,061.7	6,249.2	6,251.7	6,236.7	6,219.8	6,098.7	5,998.6	5,789.2	3.1	0.3	-0.5
Electricity	3,105.9	3,267.8	3,300.4	3,354.7	3,405.0	3,456.5	3,723.9	3,981.0	4,183.5	1.0	1.8	1.2
Losses	6,997.9	7,281.9	7,368.0	7,536.3	7,619.0	7,752.5	8,056.9	8,456.8	8,797.8	1.2	1.4	0.9
Total Primary Fuels	16,023.4	16,611.4	16,917.6	17,142.7	17,260.7	17,428.8	17,879.6	18,436.4	18,770.5	1.8	1.1	0.5
Primary Fuels Per Household	169.7	174.4	176.1	177.1	177.2	177.7	175.6	175.1	173.5	1.0	0.3	-0.1
Energy Use to GNP Ratio	2.19	2.28	2.30	2.25	2.20	2.15	1.94	1.77	1.64	1.0	-1.2	-1.7
Energy to GNP Ratio	3.89	4.05	4.07	4.01	3.94	3.87	3.54	3.26	3.08	0.5	-0.9	-1.4

6/29/92

Version: NPC LOWREF CASE

COMMERCIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH ----- 91 TO	%CH ----- 90 TO	%CH ----- 2000 TO
	1990	1991	1992	1993	1994	1995	2000	2005	2010	92	2000	2010
Coal	91.3	91.9	91.8	91.6	91.4	91.2	90.2	88.9	87.6	-0.2	-0.1	-0.3
Natural Gas	2,763.0	2,855.0	2,963.7	2,999.9	3,036.3	3,062.3	3,210.2	3,516.0	3,741.0	3.8	1.5	1.5
Petroleum	898.4	863.5	893.3	892.4	886.8	883.3	852.0	825.8	814.3	3.4	-0.5	-0.5
Distillate Fuel	486.1	444.9	476.7	473.6	467.1	461.7	427.1	397.7	378.4	7.1	-1.3	-1.2
Residual Fuel	225.2	207.7	224.6	225.3	224.6	224.5	216.6	207.7	203.5	8.1	-0.4	-0.6
Gasoline	100.6	99.8	101.0	102.3	103.7	105.4	114.7	125.0	135.8	1.1	1.3	1.7
Kerosene	13.0	33.0	13.9	14.0	14.1	14.2	14.9	15.7	16.4	-57.9	1.4	1.0
Liquefied Gases	73.6	78.1	77.2	77.2	77.3	77.5	78.7	79.8	80.2	-1.2	0.7	0.2
Other	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2
Total Direct Fuels	3,752.8	3,810.5	3,948.8	3,984.0	4,014.6	4,036.8	4,152.4	4,430.8	4,643.0	3.6	1.0	1.1
Electricity	2,804.2	2,846.0	2,850.9	2,921.3	3,009.0	3,093.9	3,353.5	3,528.9	3,667.4	0.2	1.8	0.9
Losses	6,318.1	6,341.9	6,364.5	6,562.6	6,732.9	6,939.3	7,255.4	7,496.4	7,712.6	0.4	1.4	0.6
Total Primary Fuels	12,875.1	12,998.3	13,164.2	13,467.9	13,756.5	14,070.1	14,761.3	15,456.0	16,023.0	1.3	1.4	0.8
Primary Fuels Per Square Foot	279.0	276.8	276.2	279.1	281.4	283.7	275.0	257.7	241.2	-0.2	-0.1	-1.3
Energy Use to GNP Ratio	1.59	1.62	1.64	1.61	1.60	1.58	1.49	1.41	1.36	0.8	-0.7	-0.9
Energy to GNP Ratio	3.12	3.17	3.17	3.15	3.14	3.13	2.92	2.73	2.63	-0.1	-0.7	-1.1

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Version: NPC LOWREF CASE

INDUSTRIAL DEMAND FOR ENERGY
FUEL & POWER USES
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal	2,792.8	2,607.7	2,706.5	2,703.7	2,673.6	2,661.9	2,337.4	2,193.1	2,061.4	3.8	-1.8	-1.2
Coking	1,067.3	924.6	983.9	1,007.5	992.3	997.3	717.1	524.6	382.0	6.4	-3.9	-6.1
Steam	1,723.8	1,681.0	1,722.6	1,696.3	1,681.3	1,664.6	1,620.3	1,668.5	1,679.4	2.5	-0.6	0.4
Natural Gas	8,459.2	8,521.7	8,709.0	8,708.7	8,683.2	8,684.5	8,769.9	9,032.1	8,564.2	2.2	0.4	-0.2
Fuel and Power	7,185.6	7,294.8	7,501.4	7,518.8	7,521.1	7,552.7	7,667.9	7,945.0	7,546.9	2.8	0.7	-0.2
Lease and Plant	1,273.6	1,226.9	1,207.6	1,189.9	1,162.1	1,131.8	1,102.0	1,087.1	1,017.4	-1.6	-1.4	-0.8
Petroleum	4,059.8	3,963.5	4,053.6	4,118.4	4,159.7	4,251.0	4,369.3	4,385.4	4,429.6	2.3	0.7	0.1
Distillate Fuel	1,178.6	1,116.9	1,132.1	1,144.6	1,157.8	1,177.5	1,258.6	1,272.4	1,249.3	1.4	0.7	-0.1
Residual Fuel	385.1	346.1	358.3	408.7	430.2	495.6	526.7	526.6	614.8	3.5	3.2	1.6
Liquefied Gases	332.3	405.4	411.8	414.8	420.3	425.6	442.2	459.5	452.3	1.6	2.9	0.2
Kerosene	15.8	25.5	24.6	26.5	27.7	28.8	28.4	25.8	23.5	-3.6	6.0	-1.9
Gasoline	196.1	194.6	188.9	190.4	188.8	187.3	165.7	154.2	140.1	-3.0	-1.7	-1.7
Still Gas	1,379.8	1,331.0	1,381.5	1,377.5	1,377.8	1,378.1	1,382.6	1,378.3	1,376.5	3.8	0.0	0.0
Petroleum Coke	521.0	504.4	517.0	516.5	517.7	518.8	525.7	529.3	533.7	2.5	0.1	0.2
Crude Oil	51.0	39.4	39.4	39.4	39.4	39.4	39.4	39.4	39.4	0.0	-2.5	0.0
Hydropower	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	31.0	0.0	0.0	0.0
Other	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	0.0	0.0	0.0
Total Direct Fuels	15,343.8	15,124.9	15,501.1	15,562.8	15,548.4	15,629.4	15,508.6	15,642.7	15,087.2	2.5	0.1	-0.3
Electricity	3,160.1	3,132.3	3,161.9	3,201.3	3,194.9	3,233.5	3,324.2	3,356.3	3,375.3	0.9	0.5	0.2
Losses	7,119.9	6,979.8	7,058.7	7,191.8	7,149.0	7,252.4	7,192.1	7,129.7	7,098.3	1.1	0.1	-0.1
Total Primary Fuels	25,623.7	25,237.0	25,721.7	25,956.0	25,892.3	26,115.2	26,025.0	26,128.7	25,560.8	1.9	0.2	-0.2
Primary Fuels Per Real Value of Shipments	10.93	11.11	11.15	10.88	10.59	10.33	8.95	7.85	7.05	0.4	-2.0	-2.4
Energy Use to GNP Ratio	4.49	4.46	4.49	4.39	4.28	4.19	3.73	3.36	3.03	0.9	-1.8	-2.1
Energy to GNP Ratio	6.22	6.16	6.19	6.07	5.91	5.80	5.15	4.62	4.19	0.6	-1.9	-2.0

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Version: NPC LOWREF CASE

RAW MATERIAL DEMAND FOR ENERGY
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Asphalt & Road Oil	1,166.3	1,053.8	1,041.1	1,048.2	1,059.0	1,076.0	1,152.4	1,185.8	1,204.7	-1.2	-0.1	0.4
Lubes & Waxes	396.1	353.8	375.0	385.2	392.2	399.3	429.9	461.6	480.4	6.0	0.8	1.1
Industrial Use	221.3	197.6	207.0	215.7	221.1	226.6	252.4	280.3	298.2	4.8	1.3	1.7
Transportation Use	174.8	156.2	168.0	169.5	171.0	172.7	177.5	181.3	182.1	7.5	0.2	0.3
Petroleum Coke	211.4	203.6	206.3	214.0	207.8	212.0	209.1	202.3	191.0	1.3	-0.1	-0.9
Special Naphthas	107.3	92.2	96.7	103.5	111.4	123.0	155.5	173.3	187.3	5.0	3.8	1.9
Other Petroleum Products *	126.4	-56.7	82.1	85.1	85.9	86.9	86.7	86.8	86.8	NM	-3.7	0.0
Petrochemical Feedstocks	2,389.7	2,455.9	2,435.8	2,349.2	2,289.4	2,314.2	2,677.0	2,857.5	3,026.1	-0.8	1.1	1.2
Liquefied Gases	1,194.5	1,216.2	1,202.1	1,186.5	1,154.6	1,166.4	1,351.9	1,445.9	1,534.2	-1.2	1.2	1.3
Naphtha	347.8	319.2	335.6	343.6	350.6	355.6	416.6	450.4	483.1	5.1	1.8	1.5
Still Gas	93.5	90.8	92.3	92.1	92.0	93.3	110.6	119.5	128.1	1.6	1.7	1.5
Miscellaneous	753.9	829.7	805.9	727.0	692.2	699.0	797.9	841.7	880.7	-2.9	0.6	1.0
Total	4,397.2	4,102.7	4,237.1	4,185.3	4,145.7	4,211.5	4,710.6	4,967.3	5,176.2	3.3	0.7	0.9
Total Delivered Fuel per Dollar of GNP **	1.07	1.00	1.02	0.98	0.95	0.94	0.93	0.88	0.85	1.9	-1.3	-0.9

* Other products include natural gasoline, isopentane, unfractionated stream, plant condensate, unfinished oils, motor gasoline blending components and aviation gasoline blending components. Due to inconsistencies in the classifications of some petroleum products, refinery inputs exceed total supply for these products, leaving a net negative balance.

** Thousand Btu per 1982 Dollar of GNP

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Version: NPC LOWREF CASE

TRANSPORTATION DEMAND FOR ENERGY
FUEL AND POWER USES
(Trillion Btu)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Natural Gas	680.3	772.2	674.0	643.3	647.0	655.4	888.8	1,106.5	1,158.6	-12.7	2.7	2.7
Pipeline Fuel	680.3	772.2	674.0	643.3	647.0	649.2	704.9	756.0	758.3	-12.7	0.4	0.7
Vehicle Fuel	0.0	0.0	0.0	0.0	0.0	6.2	183.9	350.5	400.2	NC	NC	8.1
Petroleum	21,539.7	21,246.1	21,108.7	21,355.1	21,641.6	22,030.8	22,715.2	23,438.6	23,176.2	-0.6	0.5	0.2
Motor Gasoline	13,573.5	13,470.0	13,300.6	13,401.9	13,507.3	13,636.4	13,602.7	13,555.7	12,955.5	-1.3	0.0	-0.5
Unreformulated	13,573.5	13,470.0	13,300.6	13,401.9	13,355.1	13,327.9	12,762.2	12,623.1	12,063.6	-1.3	-0.6	-0.6
Oxygenate	0.0	0.0	0.0	0.0	152.3	308.4	840.5	932.6	891.9	NC	NC	0.6
Distillate Fuel	3,823.2	3,778.4	3,775.5	3,821.1	3,894.2	4,006.1	4,513.6	5,081.0	5,371.4	-0.1	1.7	1.8
Jet Fuel	3,129.4	3,023.9	3,038.1	3,111.9	3,205.8	3,309.4	3,477.4	3,640.8	3,688.1	0.5	1.1	0.6
Residual Fuel	948.1	910.6	931.6	956.6	969.4	1,011.6	1,050.1	1,086.8	1,084.4	2.3	1.0	0.3
Liquefied Gases	20.4	21.7	21.3	22.1	23.3	25.8	29.8	32.8	35.3	-1.9	3.9	1.7
Aviation Gasoline	45.0	41.5	41.5	41.5	41.5	41.5	41.5	41.5	41.5	0.0	-0.8	0.0
Total	21,539.7	21,246.1	21,782.7	22,000.2	22,291.8	22,690.8	23,617.0	24,569.7	24,369.4	2.5	0.9	0.3
Electricity	18.1	24.4	19.6	19.7	20.0	20.2	21.1	21.9	22.5	-19.8	1.6	0.7
Primary Fuels Per Person	86.19	84.16	85.54	85.74	86.22	87.14	87.70	88.71	85.83	1.6	0.2	-0.2
Energy to GNP Ratio	5.23	5.19	5.25	5.15	5.10	5.05	4.68	4.35	4.00	1.2	-1.1	-1.6

6/29/92

Version: NPC LOWREF CASE

ELECTRIC UTILITIES DEMAND FOR ENERGY
USED IN THE GENERATION OF ELECTRICITY
(Trillion BTU)

	YEARS									%CH	%CH	%CH
	1990	1991	1992	1993	1994	1995	2000	2005	2010	91 TO 92	90 TO 2000	2000 TO 2010
Coal (1)	16,585.0	16,061.7	16,450.2	16,482.7	16,584.8	16,854.0	16,048.9	16,198.3	15,966.0	2.4	-0.3	-0.1
Consumption	16,079.7	16,003.3	16,215.2	16,426.6	16,556.4	16,800.5	16,240.6	16,172.0	15,972.3	1.3	0.1	-0.2
Stock Changes	417.6	58.4	235.1	56.1	28.4	53.5	-191.7	26.4	-6.4	302.4	NM	28.9
Natural Gas	2,854.1	2,848.2	2,785.4	2,966.7	3,044.3	3,050.1	4,197.9	4,925.1	5,210.7	-2.2	3.9	2.2
Petroleum (1)	1,376.9	1,286.6	1,030.2	1,129.1	1,127.4	1,385.2	1,393.9	1,575.9	2,239.3	-19.9	0.1	4.9
Residual Fuel (1)	1,263.2	1,198.1	967.7	1,048.3	1,050.2	1,277.9	1,273.4	1,412.8	1,987.3	-19.2	0.1	4.6
Consumption	1,140.1	1,206.8	979.2	1,027.4	1,043.6	1,233.6	1,300.2	1,370.5	1,931.6	-18.9	1.3	4.0
Stock Changes	123.1	-8.7	-11.5	20.9	6.6	44.3	-26.8	42.4	55.7	-32.2	NM	NM
Distillate Fuel (1)	101.8	76.9	56.1	74.4	70.9	101.0	114.1	156.8	245.6	-27.0	1.1	8.0
Consumption	86.4	77.5	64.0	69.5	71.8	86.2	113.6	136.2	215.3	-17.4	2.8	6.6
Stock Changes	15.4	-0.6	-7.9	4.9	-0.9	14.8	0.5	20.6	30.3	-1,219.4	-29.3	51.4
Other (1)	11.9	11.5	6.3	6.3	6.3	6.3	6.3	6.3	6.3	-44.9	-6.1	0.0
Nuclear Power	6,186.0	6,569.2	6,850.6	6,940.9	7,037.8	7,109.0	7,423.7	7,443.2	7,438.0	4.3	1.8	0.0
Hydropower	2,909.0	3,064.8	3,125.0	3,192.5	3,231.5	3,263.1	3,408.3	3,637.6	3,838.0	2.0	1.6	1.2
Other	200.0	196.4	206.3	222.1	222.8	231.5	353.7	308.5	251.4	5.0	5.9	-3.4
Total (2)	29,605.8	29,968.6	30,212.8	30,877.8	31,220.1	31,839.3	33,018.0	34,062.2	34,949.7	0.8	1.1	0.6
Total Electricity	9,100.8	9,282.9	9,346.7	9,511.1	9,642.9	9,818.2	10,437.0	10,902.4	11,263.2	0.7	1.4	0.8

LEGEND

(1) Product Supplied.

(2) Includes consumption of coal, product supplied of petroleum.

National Petroleum Council
Case 2
\$20 Real Oil Price Case

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January 1992

NPC CASE 2 SCENARIO

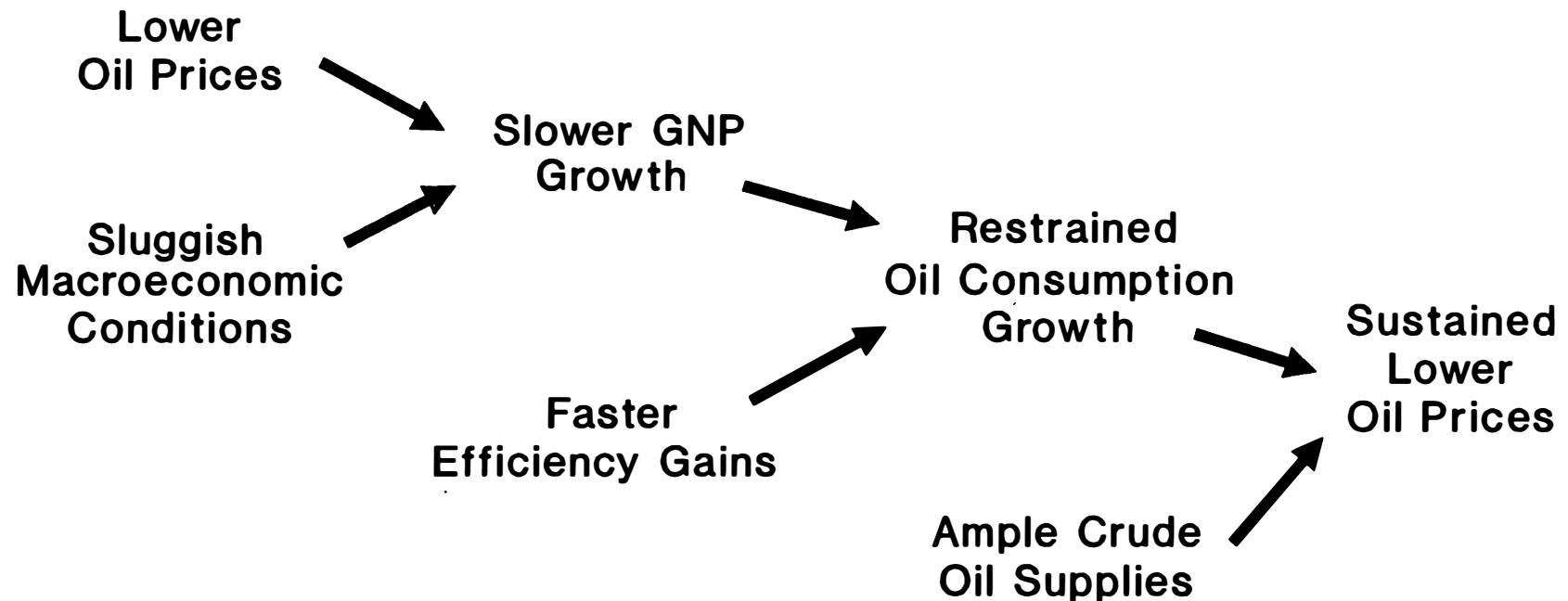
Principal Assumptions and Conclusions

- ☐ Keys to sustained low oil prices are:
 - Higher energy/oil efficiency and sluggish economic conditions, resulting in weak oil demand growth, and
 - Increased crude oil availability (willingness to supply) at low prices
- ☐ Economic growth in the U.S. is not as sluggish as in other world economies; lower oil prices provide relatively greater stimulus to U.S. economy
- ☐ Oil/GNP intensity is stronger in U.S. than other countries; yet, total non-CPE world oil consumption lags Case 1
- ☐ OPEC and non-OPEC willingness to supply oil assumed to be sufficient to ensure adequate oil supplies, despite low oil prices

Comparison of NPC Case 1 and Case 2 Scenarios

		<u>CASE 2</u>	<u>CASE 1</u>
U.S. Refiners'	1995	15.60	19.15
Cost of Crude	2000	17.10	21.25
(1990\$/Barrel)	2010	20.00	28.00
GNP/GDP Growth			
(Avg. %/Year, 1990-2010)			
United States		1.9%	2.5%
Major Seven		2.4%	3.1%
Non-Communist World		3.0%	3.8%
Non-Communist Oil	1995	56.0	58.2
Consumption(MMBD)	2000	58.5	64.8
	2010	63.3	78.8
OPEC Crude Oil	1995	26.8	29.3
Production(MMBD)	2000	29.8	37.1
	2010	33.0	51.4
Oil Consumption	0.4-0.8%/Year Improvement	---	---
Efficiency	Relative to Case 1		
Oil Demand Response	Stronger U.S. Oil		
to Price	Consumption Response to	---	---
	Lower Oil Prices		
GNP/GDP Growth	U.S. GNP Growth Rate		
	Less Influenced by	---	---
	Sluggish Economic		
	Conditions		

Faster Efficiency Gains and Ample Crude Supplies are Key to Lower Oil Prices



- o Faster efficiency gains and sluggish economic growth offset the effect of lower oil prices, restraining oil demand growth.
- o Abundant crude supplies and weak demand yield sustained lower oil prices.

1/8/92

Workspace: NPC/WOIL0291/OIL20.

WORLD OIL OUTLOOK SUMMARY
(Million Barrels Per Day)

	1990	1991	1992	1993	1995	2000	2005	2010	%CH 90 TO 91	%CH 90 TO 95	%CH 95 TO 2000	%CH 2000 TO 2005	%CH 2005 TO 2010
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
OIL CONSUMPTION													
MAJOR SEVEN	31.83	31.82	32.23	32.29	32.99	35.51	39.60	42.19	0.0	0.7	1.5	2.2	1.3
OTHER OECD	5.87	6.04	6.26	6.28	6.34	6.47	6.81	6.93	2.8	1.5	0.4	1.0	0.4
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL OECD	37.70	37.85	38.49	38.57	39.33	41.98	46.40	49.12	0.4	0.9	1.3	2.0	1.1
DEVELOPING AREAS	15.52	15.72	15.91	15.92	16.71	16.55	15.50	14.20	1.3	1.5	-0.2	-1.3	-1.7
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
NON-CPE CONSUMPTION	53.22	53.57	54.40	54.49	56.04	58.53	61.90	63.32	0.7	1.0	0.9	1.1	0.5
FORMER CPE CONSUMPTION	13.06	12.76	12.80	12.84	12.93	12.87	12.69	12.53	-2.3	-0.2	-0.1	-0.3	-0.3
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
WORLD CONSUMPTION	66.54	66.33	67.20	67.33	68.97	71.40	74.60	75.85	-0.3	0.7	0.7	0.9	0.3
OIL PRODUCTION													
MAJOR SEVEN	13.07	13.25	13.18	12.93	12.35	11.41	10.59	9.78	1.4	-1.1	-1.6	-1.5	-1.6
OTHER NON-OPEC	12.26	12.49	12.53	12.58	12.66	13.25	14.20	15.24	1.9	0.6	0.9	1.4	1.4
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
TOTAL NON-OPEC	25.32	25.74	25.71	25.51	25.01	24.65	24.79	25.02	1.6	-0.3	-0.3	0.1	0.2
OPEC CRUDE	23.00	23.38	24.80	25.45	26.85	29.81	32.37	32.96	1.7	3.1	2.1	1.7	0.4
OPEC NGLs	1.90	1.87	1.89	1.91	1.95	2.02	2.12	2.23	-1.7	0.5	0.7	1.0	1.0
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TOTAL OPEC PRODUCTION	24.91	25.25	26.69	27.36	28.80	31.83	34.49	35.18	1.4	3.0	2.0	1.6	0.4
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
NON-CPE PRODUCTION	50.23	50.99	52.40	52.87	53.81	56.48	59.28	60.20	1.5	1.4	1.0	1.0	0.3

									%CH 90 TO 91	%CH 90 TO 95	%CH 95 TO 2000	%CH 2000 TO 2005	%CH 2005 TO 2010
	1990	1991	1992	1993	1995	2000	2005	2010					
FORMER CPE PRODUCTION	14.64	14.22	14.19	14.21	14.15	13.88	14.24	14.65	-2.8	-0.7	-0.4	0.5	0.6
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
WORLD PRODUCTION	65.25	65.21	66.59	67.09	67.96	70.36	73.52	74.85	-0.1	0.8	0.7	0.9	0.4
REFINERY GAIN	1.12	1.12	1.14	1.14	1.18	1.23	1.30	1.33	0.7	1.0	0.9	1.1	0.5
INVENTORY WITHDRAWALS (*)	0.29	-0.01	-0.53	-0.90	-0.17	-0.19	-0.22	-0.33	NM	NM	-2.5	-2.8	-8.6
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
TOTAL WORLD SUPPLY	66.54	66.33	67.20	67.33	68.97	71.40	74.60	75.85	-0.3	0.7	0.7	0.9	0.3
NET EXPORTS FROM FORMER CPEs	1.58	1.46	1.39	1.37	1.23	1.01	1.54	2.13	-7.6	-4.9	-3.8	8.8	6.6
AVERAGE U.S. REFINERS' COST OF FOREIGN CRUDE													
1990 \$/BARREL	22.15	18.46	17.73	17.00	15.57	17.07	18.58	20.08	-16.6	-6.8	1.9	1.7	1.6
CURRENT \$/BARREL	22.15	19.04	18.84	18.56	18.00	23.38	31.07	41.42	-14.0	-4.1	5.4	5.9	5.9

* Negative values indicate an inventory build;
includes statistical discrepancy.

1/8/92

Workspace: NPC/WOIL0291/OIL20.

**MAJOR SEVEN
GROWTH IN REAL GDP
(Annualized Rates of Growth)**

	YEARS								%CH	%CH	%CH	%CH	%CH
	1990	1991	1992	1993	1995	2000	2005	2010	90 TO 91	90 TO 95	95 TO 2000	2000 TO 2005	2005 TO 2010
UNITED STATES	0.9	-0.2	2.0	2.1	2.5	1.8	1.9	1.7	-0.2	1.8	2.1	2.0	1.7
CANADA	0.7	-1.0	2.5	2.7	2.9	2.9	2.3	2.4	-1.0	1.9	2.6	2.2	2.4
JAPAN	5.9	3.1	2.9	3.3	3.7	3.0	3.2	3.2	3.1	3.4	3.1	3.1	3.2
UNITED KINGDOM	1.0	-1.1	1.3	1.8	2.6	2.3	2.4	2.5	-1.1	1.4	2.1	2.3	2.5
W. GERMANY	4.5	2.9	1.9	2.6	3.6	3.1	2.9	2.9	2.9	2.7	3.3	2.8	2.8
FRANCE	2.6	1.8	1.7	2.2	3.4	2.8	3.0	3.1	1.8	2.4	2.8	2.9	3.0
ITALY	1.9	1.5	1.5	2.3	2.6	2.5	2.8	2.9	1.5	2.0	2.5	2.7	2.8
MAJOR SEVEN	2.5	1.0	2.1	2.4	3.0	2.4	2.5	2.5	1.0	2.2	2.6	2.5	2.4
WORLD EXCL. CPEs	2.8	1.9	2.4	2.9	3.5	3.1	3.2	3.3	1.9	2.8	3.1	3.1	3.2

1/8/92

Workspace: NPC/WOIL0291/OIL20.

WORLD OIL SUPPLY/DEMAND BALANCE
(Million Barrels Per Day)

	1990	1991	1992	1993	1995	2000	2005	2010	%CH 90 TO 91	%CH 90 TO 95	%CH 95 TO 2000	%CH 2000 TO 2005	%CH 2005 TO 2010
	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----	-----
OIL CONSUMPTION													
UNITED STATES	16.91	16.75	16.91	16.91	17.41	19.10	21.73	23.63	-0.9	0.6	1.9	2.6	1.7
CANADA	1.76	1.73	1.76	1.77	1.78	1.85	1.91	1.93	-1.7	0.2	0.8	0.6	0.2
JAPAN	5.24	5.19	5.27	5.32	5.46	5.88	6.67	7.07	-1.0	0.8	1.5	2.6	1.2
UNITED KINGDOM	1.76	1.78	1.78	1.76	1.74	1.84	1.94	2.09	1.0	-0.3	1.1	1.0	1.5
W. GERMANY	2.41	2.55	2.64	2.68	2.74	2.73	2.91	2.92	5.8	2.6	-0.1	1.3	0.1
FRANCE	1.83	1.87	1.89	1.88	1.91	2.02	2.19	2.27	2.3	0.9	1.1	1.7	0.7
ITALY	1.91	1.94	1.98	1.97	1.96	2.09	2.25	2.29	1.7	0.6	1.3	1.5	0.3
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MAJOR SEVEN	31.83	31.82	32.23	32.29	32.99	35.51	39.60	42.19	0.0	0.7	1.5	2.2	1.3
OTHER OECD	5.87	6.04	6.26	6.28	6.34	6.47	6.81	6.93	2.8	1.5	0.4	1.0	0.4
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TOTAL OECD	37.70	37.85	38.49	38.57	39.33	41.98	46.40	49.12	0.4	0.9	1.3	2.0	1.1
NON-OPEC LDCs	11.07	11.18	11.28	11.24	11.87	12.20	12.13	11.89	1.0	1.4	0.6	-0.1	-0.4
OPEC	4.25	4.33	4.42	4.49	4.65	4.16	3.18	2.12	1.9	1.8	-2.2	-5.2	-7.8
U.S. TERRITORIES	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	-1.2	-0.8	-0.5	-0.2	0.5
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
NON-COMMUNIST CONSUMPTION	53.22	53.57	54.40	54.49	56.04	58.53	61.90	63.32	0.7	1.0	0.9	1.1	0.5
CENTRALLY-PLANNED ECON.	13.06	12.76	12.80	12.84	12.93	12.87	12.69	12.53	-2.3	-0.2	-0.1	-0.3	-0.3
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
WORLD CONSUMPTION	66.54	66.33	67.20	67.33	68.97	71.40	74.60	75.85	-0.3	0.7	0.7	0.9	0.3

	1990	1991	1992	1993	1995	2000	2005	2010	%CH 90 TO 91	%CH 90 TO 95	%CH 95 TO 2000	%CH 2000 TO 2005	%CH 2005 TO 2010
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OIL PRODUCTION													
UNITED STATES	8.85	8.87	8.75	8.56	8.27	7.62	7.04	6.45	0.2	-1.3	-1.6	-1.6	-1.7
CANADA	1.93	1.90	1.84	1.89	1.81	1.89	1.99	2.04	-1.3	-1.3	0.9	1.0	0.5
JAPAN	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.0	0.0	0.0	0.0	0.0
UNITED KINGDOM	1.99	2.18	2.31	2.20	1.98	1.63	1.29	1.04	9.6	-0.1	-3.9	-4.5	-4.2
W. GERMANY	0.08	0.08	0.08	0.08	0.08	0.07	0.07	0.07	0.0	-0.8	-0.8	0.0	-0.5
FRANCE	0.09	0.08	0.08	0.08	0.08	0.08	0.07	0.07	-1.2	-1.0	-0.9	-1.3	-1.3
ITALY	0.12	0.12	0.11	0.11	0.11	0.11	0.11	0.10	-0.8	-0.3	-0.9	-0.9	-0.8
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MAJOR SEVEN	13.07	13.25	13.18	12.93	12.35	11.41	10.59	9.78	1.4	-1.1	-1.6	-1.5	-1.6
OTHER NON-OPEC	12.26	12.49	12.53	12.58	12.66	13.25	14.20	15.24	1.9	0.6	0.9	1.4	1.4
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TOTAL NON-OPEC	25.32	25.74	25.71	25.51	25.01	24.65	24.79	25.02	1.6	-0.3	-0.3	0.1	0.2
OPEC CRUDE	23.00	23.38	24.80	25.45	26.85	29.81	32.37	32.96	1.7	3.1	2.1	1.7	0.4
OPEC NGLs	1.90	1.87	1.89	1.91	1.95	2.02	2.12	2.23	-1.7	0.5	0.7	1.0	1.0
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OPEC	24.91	25.25	26.69	27.36	28.80	31.83	34.49	35.18	1.4	3.0	2.0	1.6	0.4
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NON-COMMUNIST PRODUCTION	50.23	50.99	52.40	52.87	53.81	56.48	59.28	60.20	1.5	1.4	1.0	1.0	0.3
CENTRALLY-PLANNED ECON.	14.64	14.22	14.19	14.21	14.15	13.88	14.24	14.65	-2.8	-0.7	-0.4	0.5	0.6
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
WORLD PRODUCTION	65.25	65.21	66.59	67.09	67.96	70.36	73.52	74.85	-0.1	0.8	0.7	0.9	0.4
REFINERY GAIN	1.12	1.12	1.14	1.14	1.18	1.23	1.30	1.33	0.7	1.0	0.9	1.1	0.5
INVENTORY WITHDRAWALS (*)	0.29	-0.01	-0.53	-0.90	-0.17	-0.19	-0.22	-0.33	NM	NM	-2.5	-2.8	-8.6
	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====	=====
TOTAL WORLD SUPPLY	66.54	66.33	67.20	67.33	68.97	71.40	74.60	75.85	-0.3	0.7	0.7	0.9	0.3
NET EXPORTS FROM FORMER CPES	1.58	1.46	1.39	1.37	1.23	1.01	1.54	2.13	-7.6	-4.9	-3.8	8.8	6.6

* Negative values indicate an inventory build;
includes statistical discrepancy

1/31/92

U.S. Economic Outlook

	YEARS							Average Annual Compound Growth			

	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Composition of Real GNP (Annual rate of change)											
Gross National Product	1.0	-0.2	2.0	2.5	1.8	1.9	1.7	1.8	2.1	2.0	1.7
Final Sales	1.6	0.0	1.3	2.6	1.9	1.9	1.7	1.7	2.1	2.0	1.7
Excluding CCC Transactions	1.6	-0.1	1.3	2.6	1.9	1.9	1.7	1.7	2.1	2.0	1.7
Total Consumption	0.9	0.4	1.6	1.6	1.4	1.4	1.4	1.4	1.3	1.6	1.4
Nonresidential Fixed Investment	1.8	-3.4	7.0	6.5	2.9	2.9	2.9	5.1	4.2	3.3	2.9
Equipment	2.8	-1.8	9.4	6.1	3.7	3.2	3.2	6.1	4.9	3.4	3.2
Structures	-1.2	-8.9	-1.6	8.5	-0.9	1.4	1.6	1.5	1.5	2.4	1.4
Residential Fixed Investment	-5.4	-11.5	7.3	4.3	1.4	0.6	2.4	1.4	1.2	0.7	1.0
Exports	6.4	3.1	2.4	6.6	5.7	4.2	3.2	5.3	6.4	4.6	3.5
Imports	2.8	0.1	6.6	4.5	4.1	3.2	3.2	4.8	4.1	3.6	3.1
Federal Government	2.6	1.3	-4.8	-1.9	-0.2	1.3	0.9	-3.1	-1.0	0.9	1.0
Excluding CCC Transactions	1.7	0.6	-4.6	-1.9	-0.2	1.3	0.9	-3.2	-1.0	0.9	1.0
State and Local Governments	3.0	0.9	2.1	2.3	0.8	0.7	0.7	2.0	1.1	0.7	0.6
Billions of Dollars											
Real GNP (1982 \$)	4,157.3	4,150.0	4,234.8	4,540.0	5,031.5	5,551.8	6,034.8	1.8	2.1	2.0	1.7
Gross National Product	5,465.2	5,661.4	5,940.3	6,881.5	8,981.4	11,962.7	15,834.5	4.7	5.5	5.9	5.8
Prices and Wages (Annual rate of change)											
GNP Price Deflator (Implicit)	4.1	3.8	2.8	2.6	3.8	3.8	4.2	2.9	3.3	3.8	4.0
GNP Price Index (Fixed-Weight)	4.6	4.0	3.4	3.3	4.3	4.4	4.7	3.5	4.0	4.4	4.5
CPI--All Urban Consumers	5.4	4.3	3.2	3.0	4.0	4.1	4.4	3.5	3.7	4.1	4.2
Producer Price Index--Finished Goods	4.9	2.4	2.5	2.2	3.9	3.9	4.2	2.5	3.7	3.8	4.0
Employment Cost Index - Total Comp.	5.0	4.4	4.2	4.7	5.3	5.4	5.4	4.2	5.2	5.5	5.4
Output per Hour	-0.9	1.2	1.8	1.5	1.5	1.5	1.2	1.4	1.6	1.7	1.3

	YEARS							Average Annual Compound Growth			
	-----							-----			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Production and Other Key Measures											
Industrial Production (1987=1.000)	1.092	1.073	1.108	1.200	1.353	1.514	1.657	1.9	2.4	2.3	1.8
Annual Rate of Change	1.0	-1.7	3.2	2.6	2.3	2.1	1.8	1.9	2.4	2.3	1.8
Nonfarm Inven Accum (Billion 1982 \$)	-5.1	-11.3	18.2	12.6	17.4	19.9	19.9	NM	6.7	2.7	0.0
Housing Starts (Mil units)	1.203	1.021	1.095	1.215	1.258	1.180	1.176	0.2	0.7	-1.3	-0.1
Retail Unit Car Sales (Mil units)	9.5	8.8	9.4	10.0	10.0	10.4	10.4	0.9	0.1	0.8	0.0
Civilian Unemployment Rate (%)	5.5	6.7	6.4	5.7	5.8	5.6	5.6	0.7	0.2	-0.7	0.1
Nonfarm Empl. (Estab. survey, % change)	1.5	-0.9	0.4	1.3	0.6	0.4	0.6	0.7	0.7	0.4	0.5
Fed. Budget Surplus (Unified, FY, bil. \$)	-236.1	-269.5	-360.6	-238.1	-266.2	-329.1	-526.6	-0.2	-2.3	-4.3	-9.9
Foreign Trade											
Current Account Balance (Billion \$)	-92.128	-10.124	-77.788	-89.173	-42.399	19.680	71.884	0.6	13.8	NM	29.6
Merch. Trade Balance (c.v.b., bil. \$)	-101.7	-64.7	-94.2	-113.1	-64.8	-35.7	-39.9	-2.1	10.5	11.3	-2.3
Foreign Crude Oil (\$ per barrel)	22.22	18.92	18.92	17.95	23.18	30.46	39.37	-4.2	5.2	5.6	5.3
U.S. Dollar Exchange Rate (% change)	-5.2	0.8	1.4	0.7	-1.1	-0.4	-0.4	0.3	-1.2	-0.7	-0.4
Foreign GDP (% change)	3.0	1.8	2.1	3.7	3.6	3.3	2.8	2.9	3.6	3.5	3.0
Financial Markets											
Money Supply (M2, billion \$)	3,325.1	3,438.7	3,586.0	4,315.4	5,740.0	7,563.1	10,025.7	5.4	5.9	5.7	5.8
Percent Change vs Year Ago (Q4/Q4)	3.8	3.4	4.3	7.6	5.6	5.8	6.0	5.4	5.9	5.7	5.8
AA Corp Utility Rate (%)	9.66	9.28	9.66	9.44	9.71	9.65	9.73	-0.4	0.6	-0.1	0.2
Thirty-Year Treasury Bond Rate (%)	8.61	8.37	8.63	8.10	8.44	8.41	8.61	-1.2	0.8	-0.1	0.5
Treasury Bill Rate (%)	7.49	5.71	6.42	5.97	6.12	5.96	5.68	-4.5	0.5	-0.5	-0.9
Federal Funds Rate (%)	8.10	6.03	6.74	6.58	6.64	6.50	6.06	-4.1	0.2	-0.4	-1.4
Prime Rate (%)	10.01	8.79	9.27	8.14	8.16	8.01	7.53	-4.0	0.0	-0.4	-1.2
S&P Index of 500 Common Stocks	335	375	386	417	459	625	798	4.5	1.9	6.4	5.0

	YEARS							Average Annual Compound Growth			
	-----							-----			
	1990	1991	1992	1995	2000	2005	2010	1990 1995	1995 2000	2000 2005	2005 2010
Incomes											
Personal Income (Billion \$)	4,645.5	4,804.0	5,053.0	5,947.8	7,805.0	10,431.2	13,939.3	5.1	5.6	6.0	6.0
Real Disposable Income (% change)	0.9	-0.7	1.7	2.1	1.4	1.8	1.6	1.5	1.5	1.7	1.6
Saving Rate (%)	4.6	3.6	3.8	5.1	6.3	7.1	8.4	2.2	4.3	2.3	3.5
Profits After Tax (Billion \$)	172.6	190.2	206.5	184.3	211.3	246.4	311.2	1.3	2.8	3.1	4.8
Post-Tax Corp Cash Flow (Billion \$)	529.1	564.5	588.1	652.4	800.0	1,036.5	1,365.7	4.3	4.2	5.3	5.7
Percent Change vs Year Ago	1.2	6.7	4.2	3.1	5.8	4.3	6.8	4.3	4.2	5.3	5.7

CHAPTER FIVE
**EEA MODEL OUTPUT FOR
REFERENCE, SENSITIVITY, AND
OPTION CASES**

CASE 1
NPC High Reference Case
No. 3 Final

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,816	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,345	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,088	17,350	75.4	82.9	1.04	1.25
1992	18.46	1.32	1.49	1.48	41.6	13,718	17,563	78.1	85.5	1.00	1.35
1993	18.60	1.53	1.70	1.63	47.6	13,789	17,731	77.8	88.5	0.99	1.57
1994	18.76	1.73	1.90	1.80	53.4	14,676	17,688	83.0	91.2	1.00	1.76
1995	19.01	1.98	2.15	2.04	60.4	15,080	17,797	84.7	93.6	1.03	1.96
1996	19.25	2.19	2.36	2.23	66.0	15,658	17,646	88.7	94.1	1.06	2.11
1997	19.56	2.33	2.50	2.36	69.0	15,928	17,843	89.3	94.8	1.06	2.25
1998	19.91	2.47	2.64	2.51	72.0	16,259	17,834	91.2	95.1	1.06	2.39
1999	20.51	2.66	2.82	2.70	75.1	17,619	17,936	98.2	95.4	1.06	2.57
2000	21.10	2.88	3.05	2.94	79.2	18,684	18,275	102.2	95.6	1.06	2.78
2001	21.75	2.87	3.03	2.92	76.4	20,434	18,628	109.7	95.6	1.06	2.77
2002	22.55	2.81	2.98	2.87	72.4	21,093	18,981	111.1	95.2	1.06	2.71
2003	23.45	2.80	2.97	2.85	69.3	21,758	19,324	112.6	94.7	1.06	2.70
2004	24.25	2.79	2.96	2.84	66.8	22,239	19,696	112.9	94.3	1.06	2.69
2005	25.14	2.76	2.93	2.79	63.7	22,175	19,977	111.0	93.8	1.05	2.69
2006	25.74	2.75	2.91	2.77	61.9	21,508	20,164	106.7	93.5	1.03	2.71
2007	26.25	2.87	3.03	2.87	63.3	20,762	20,277	102.4	93.7	1.03	2.83
2008	26.75	3.09	3.26	3.08	67.0	20,572	20,364	101.0	94.2	1.02	3.08
2009	27.35	3.40	3.57	3.36	72.1	21,133	20,404	103.6	94.9	1.01	3.42
2010	27.85	3.47	3.63	3.43	72.2	22,482	20,450	109.9	94.9	1.00	3.53
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)

Run Date: 08/16/92

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DEMAND												
RESIDENTIAL	4,900	4,497	4,700	4,852	4,852	4,860	4,891	4,891	4,889	4,881	4,879	4,865
COMMERCIAL *	2,771	2,729	2,846	2,849	2,844	2,856	2,877	2,881	2,878	2,882	2,914	2,956
INDUSTRIAL	6,939	7,046	7,376	7,409	7,637	7,764	7,834	7,761	7,787	7,797	7,800	7,867
BOILERS	2,791	2,831	2,983	2,922	3,006	3,077	3,122	3,106	3,106	3,106	3,111	3,114
NONBOILERS	4,148	4,215	4,392	4,488	4,631	4,687	4,712	4,655	4,680	4,691	4,689	4,753
ELECTRIC UTILITY	2,808	2,852	2,905	2,892	2,903	2,933	3,064	3,163	3,368	3,466	3,595	3,866
TOTAL END USE DEMAND	17,417	17,125	17,826	18,001	18,236	18,413	18,666	18,696	18,921	19,026	19,188	19,555
LEASE AND PLANT USE	886	1,061	1,093	1,108	1,115	1,110	1,115	1,102	1,112	1,110	1,115	1,135
TRANSMISSION FUEL	655	644	670	677	688	692	702	703	711	715	722	735
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547
TOTAL DISPOSITION	19,137	19,001	19,847	20,105	20,425	20,646	20,945	20,984	21,245	21,367	21,556	21,973
SUPPLY												
LOWER-48 PRODUCTION	17,651	17,341	17,938	18,065	18,239	18,189	18,295	18,135	18,331	18,326	18,428	18,794
PIPELINE IMPORTS	1,326	1,465	1,709	1,836	1,969	2,211	2,392	2,503	2,521	2,543	2,558	2,562
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	244	328	372	474	544	589
TOTAL GAS SUPPLY	19,130	18,998	19,843	20,099	20,420	20,635	20,930	20,966	21,224	21,343	21,530	21,946

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,855	4,856	4,864	4,878	4,885	4,891	4,896	4,903	4,911	4,921	0	0	0	0
COMMERCIAL *	3,013	3,073	3,146	3,223	3,296	3,348	3,406	3,457	3,491	3,502	0	0	0	0
INDUSTRIAL	8,044	8,219	8,332	8,477	8,534	8,630	8,751	8,811	8,844	8,908	0	0	0	0
BOILERS	3,234	3,345	3,424	3,518	3,561	3,620	3,695	3,728	3,741	3,783	0	0	0	0
NONBOILERS	4,810	4,874	4,908	4,959	4,974	5,010	5,057	5,083	5,103	5,125	0	0	0	0
ELECTRIC UTILITY	4,074	4,196	4,312	4,430	4,571	4,726	4,883	5,046	5,222	5,352	0	0	0	0
TOTAL END USE DEMAND	19,987	20,345	20,655	21,008	21,287	21,595	21,936	22,217	22,468	22,682	0	0	0	0
LEASE AND PLANT USE	1,155	1,175	1,196	1,218	1,234	1,244	1,248	1,253	1,253	1,253	0	0	0	0
TRANSMISSION FUEL	752	765	777	790	800	812	825	835	845	853	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,409	22,768	23,079	23,436	23,710	23,991	24,302	24,587	24,848	24,985	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,133	19,517	19,871	20,259	20,564	20,756	20,875	20,964	21,003	21,100	0	0	0	0
PIPELINE IMPORTS	2,681	2,749	2,730	2,747	2,751	2,839	3,019	3,167	3,319	3,371	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	561	487	466	422	387	384	392	436	502	494	0	0	0	0
TOTAL GAS SUPPLY	22,375	22,753	23,067	23,428	23,702	23,979	24,286	24,567	24,824	24,965	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)

Run Date: 08/16/92

Run Time: 02:04 PM

ENERGY DEMAND FOR COMBUSTION USES
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,417	17,125	17,826	18,001	18,236	18,413	18,666	18,696	18,921	19,026	19,188	19,555
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,957	1,867	1,891	1,923	2,068	2,065	2,121	2,209	2,182
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,612	2,623	2,624	2,618	2,622	2,625	2,628	2,618
LPG (RES/COM SECTORS)	470	429	421	426	428	427	426	424	421	418	415	411
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,081	18,145	18,234	18,398	18,644	18,860	19,097	19,257
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,226
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,276	49,986	50,541	51,034	51,472	51,909	52,365	52,851	53,322	53,825	54,406
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,578	9,685	9,794	9,960	10,128	10,299	10,473	10,651
LESS ELEC UTIL ENERGY INPUT	(19,793)	(20,169)	(20,294)	(20,439)	(20,616)	(20,790)	(20,994)	(21,223)	(21,456)	(21,640)	(21,833)	(22,017)
END USE ENERGY DEMAND	38,456	38,319	39,063	39,575	39,996	40,367	40,709	41,101	41,523	41,981	42,465	43,039

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	19,987	20,345	20,655	21,008	21,287	21,595	21,936	22,217	22,468	22,682	0	0	0	0
RESIDUAL FUEL OIL	1,978	1,862	1,815	1,774	1,798	1,817	1,807	1,863	1,911	1,872	0	0	0	0
DISTILLATE FUEL OIL	2,624	2,630	2,629	2,631	2,629	2,629	2,634	2,634	2,631	2,628	0	0	0	0
LPG (RES/COM SECTORS)	408	404	400	396	393	389	386	383	380	378	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,623	20,011	20,431	20,833	21,210	21,588	21,966	22,345	22,728	23,200	0	0	0	0
HYDRO/RENEWABLES	3,252	3,281	3,313	3,345	3,379	3,413	3,448	3,483	3,522	3,570	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	54,978	55,587	56,247	56,941	57,599	58,282	58,978	59,676	60,342	60,982	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,838	11,029	11,224	11,422	11,624	11,831	12,042	12,257	12,476	12,699	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(22,251)	(22,505)	(22,780)	(23,073)	(23,367)	(23,677)	(23,997)	(24,337)	(24,683)	(25,040)	0	0	0	0
END USE ENERGY DEMAND	43,564	44,111	44,690	45,289	45,855	46,436	47,023	47,596	48,135	48,641	0	0	0	0

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)										Run Date: 08/16/92		
										Run Time: 02:04 PM		
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,363	3,401	3,457	3,514	3,572	3,631	3,691
DISTILLATE OIL	1,165	898	877	897	899	892	885	876	867	857	844	831
LPG	400	364	358	361	363	363	362	360	358	355	352	348
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,497	4,700	4,852	4,852	4,860	4,891	4,891	4,889	4,881	4,879	4,865
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,572	8,960	9,245	9,459	9,498	9,537	9,598	9,644	9,688	9,724	9,765	9,794
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,049	3,095	3,142	3,189	3,237	3,285
DISTILLATE OIL	561	518	509	521	526	528	524	523	522	521	521	524
LPG	70	65	63	65	64	65	64	64	64	63	63	63
COAL	88	94	88	94	94	95	94	94	93	93	92	93
NATURAL GAS	2,771	2,729	2,846	2,849	2,844	2,856	2,877	2,881	2,878	2,882	2,914	2,956
RESIDUAL OIL	228	226	223	220	214	210	207	203	199	195	193	191
TOTAL FUELS	6,472	6,494	6,653	6,703	6,729	6,770	6,815	6,859	6,896	6,942	7,020	7,113
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,409	7,637	7,764	7,834	7,761	7,787	7,797	7,800	7,867
HIGH SULFUR RESID	311	288	249	270	253	250	236	275	256	295	323	347
LOW SULFUR RESID	301	286	252	303	274	280	289	371	442	482	514	570
DISTILLATE	1,133	1,167	1,103	1,096	1,109	1,117	1,121	1,116	1,121	1,118	1,115	1,113
ELECTRICITY	3,135	3,212	3,195	3,231	3,268	3,305	3,344	3,407	3,472	3,538	3,606	3,674
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,678	1,708	1,733	1,786	1,849	1,910
TOTAL FUELS	13,471	13,653	13,794	13,940	14,191	14,375	14,501	14,638	14,811	15,016	15,206	15,481
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,892	2,903	2,933	3,064	3,163	3,368	3,466	3,595	3,866
HIGH SULFUR RESID	590	490	477	567	470	483	470	550	544	550	561	482
LOW SULFUR RESID	858	671	634	597	656	668	722	669	624	600	619	592
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	150
COAL	15,842	16,067	16,009	16,085	16,276	16,332	16,402	16,536	16,758	16,922	17,097	17,195
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,383
TOTAL FUELS	28,733	29,381	29,664	29,912	30,194	30,475	30,788	31,183	31,584	31,939	32,306	32,668
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,417	17,125	17,826	18,001	18,236	18,413	18,666	18,696	18,921	19,026	19,188	19,555
HIGH SULFUR RESID	901	778	726	837	723	733	705	826	800	845	883	829
LOW SULFUR RESID	1,387	1,184	1,109	1,120	1,145	1,158	1,218	1,243	1,265	1,276	1,325	1,353
DISTILLATE	2,988	2,640	2,556	2,588	2,612	2,623	2,624	2,618	2,622	2,625	2,628	2,618
COAL	17,640	17,878	17,775	17,870	18,081	18,145	18,234	18,398	18,644	18,860	19,097	19,257
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,237	10,400	10,462	10,585	10,600	10,690	10,703	10,794
TOTAL FUELS	49,308	49,276	49,986	50,541	51,034	51,472	51,909	52,365	52,851	53,322	53,825	54,406

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,752	3,815	3,878	3,942	4,008	4,074	4,141	4,210	4,280	4,351	0	0	0	0
DISTILLATE OIL	817	804	790	776	764	751	740	729	720	710	0	0	0	0
LPG	344	340	335	331	327	323	319	316	313	311	0	0	0	0
COAL	59	58	58	58	58	57	57	57	57	56	0	0	0	0
NATURAL GAS	4,855	4,856	4,864	4,878	4,885	4,891	4,896	4,903	4,911	4,921	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,827	9,872	9,925	9,985	10,040	10,096	10,153	10,215	10,280	10,349	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,335	3,385	3,435	3,487	3,539	3,593	3,646	3,701	3,757	3,813	0	0	0	0
DISTILLATE OIL	530	533	537	539	544	546	550	553	554	553	0	0	0	0
LPG	64	64	65	65	66	66	67	67	67	67	0	0	0	0
COAL	94	94	95	96	97	97	98	99	99	98	0	0	0	0
NATURAL GAS	3,013	3,073	3,146	3,223	3,296	3,348	3,406	3,457	3,491	3,502	0	0	0	0
RESIDUAL OIL	191	191	192	193	194	194	194	194	193	192	0	0	0	0
TOTAL FUELS	7,227	7,341	7,470	7,603	7,736	7,843	7,961	8,070	8,161	8,225	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	8,044	8,219	8,332	8,477	8,534	8,630	8,751	8,811	8,844	8,908	0	0	0	0
HIGH SULFUR RESID	296	242	218	199	198	197	194	195	202	200	0	0	0	0
LOW SULFUR RESID	520	472	457	426	419	415	381	397	415	396	0	0	0	0
DISTILLATE	1,124	1,136	1,143	1,153	1,155	1,161	1,170	1,174	1,175	1,179	0	0	0	0
ELECTRICITY	3,751	3,830	3,910	3,993	4,077	4,164	4,254	4,345	4,439	4,535	0	0	0	0
COAL	1,937	1,970	2,012	2,032	2,072	2,099	2,117	2,132	2,143	2,152	0	0	0	0
TOTAL FUELS	15,672	15,868	16,071	16,280	16,455	16,666	16,868	17,054	17,218	17,369	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,074	4,196	4,312	4,430	4,571	4,726	4,883	5,046	5,222	5,352	0	0	0	0
HIGH SULFUR RESID	412	366	347	337	342	343	347	348	350	350	0	0	0	0
LOW SULFUR RESID	559	591	601	619	645	668	691	728	750	735	0	0	0	0
DISTILLATE	153	156	160	163	167	171	174	178	182	186	0	0	0	0
COAL	17,534	17,888	18,267	18,647	18,984	19,335	19,694	20,058	20,430	20,894	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,358	10,337	10,317	10,299	10,282	10,265	10,250	10,235	10,223	10,222	0	0	0	0
TOTAL FUELS	33,090	33,534	34,004	34,495	34,991	35,507	36,038	36,594	37,158	37,738	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	19,987	20,345	20,655	21,008	21,287	21,595	21,936	22,217	22,468	22,682	0	0	0	0
HIGH SULFUR RESID	708	607	565	536	540	541	541	544	553	550	0	0	0	0
LOW SULFUR RESID	1,270	1,254	1,249	1,238	1,258	1,276	1,266	1,319	1,359	1,322	0	0	0	0
DISTILLATE	2,624	2,630	2,629	2,631	2,629	2,629	2,634	2,634	2,631	2,628	0	0	0	0
COAL	19,623	20,011	20,431	20,833	21,210	21,588	21,966	22,345	22,728	23,200	0	0	0	0
ALL OTHER FUELS	10,765	10,741	10,717	10,695	10,674	10,654	10,636	10,618	10,604	10,600	0	0	0	0
TOTAL FUELS	54,977	55,587	56,247	56,941	57,598	58,282	58,978	59,676	60,342	60,982	0	0	0	0

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)											Run Date: 08/16/92	
TABLE 2: LOWER 48 WELLS AND RESERVES											Run Time: 02:04 PM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,536	4,703	4,493	5,502	6,295	6,678	7,142	8,075	9,596	11,346
DEVELOPMENT WELLS	22,582	27,158	26,372	21,929	21,013	26,736	30,763	30,993	29,928	30,147	32,859	35,568
TOTAL GAS WELLS	9,472	10,333	9,829	7,640	7,792	8,538	9,768	10,460	11,298	11,478	12,248	12,577
TOTAL WELLS	28,326	33,314	31,907	26,632	25,505	32,238	37,058	37,671	37,070	38,222	42,454	46,913
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	938	1,690	1,502	1,446	1,354	1,285	1,201	1,199	1,283	1,413
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,015	1,879	1,697	1,704	1,623	1,606	1,559	1,556	1,659	1,812
HIGH PERMEABILITY (BCF)	9,905	12,223	7,433	7,956	8,864	9,275	9,731	10,182	10,608	10,598	11,409	12,045
LOW PERMEABILITY (BCF)	1,339	1,691	1,497	1,793	1,097	1,279	1,060	1,038	1,149	1,198	1,422	1,737
DEVONIAN SHALE (BCF)	384	504	399	326	340	448	526	617	741	878	971	918
COAL BED METHANE (BCF)	1,607	2,111	2,400	1,446	1,501	1,518	1,620	1,584	1,121	986	1,031	1,022
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	152	315	367	428	501	543	554	437
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	136	137	137	153	203	250	501	573	713
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,073	11,839	12,092	12,972	13,457	14,052	14,369	14,703	15,960	16,872
TOTAL OIL (MMB)	1,194	1,388	938	1,690	1,502	1,446	1,354	1,285	1,201	1,199	1,283	1,413
TOTAL GAS (BCF)	15,127	18,454	13,088	13,718	13,789	14,676	15,080	15,658	15,928	16,259	17,619	18,684
TOTAL NGL (MMB)	550	681	429	527	520	551	563	591	624	635	697	750
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,723	1,712	1,683	1,666	1,672	1,669	1,659	1,652	1,653
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,483	2,376	2,240	2,170	2,141	2,130	2,100	2,062	2,041
HIGH PERMEABILITY (BCF)	12,037	12,432	12,374	12,369	12,506	12,478	12,488	12,305	12,377	12,249	12,175	12,296
LOW PERMEABILITY (BCF)	1,664	1,673	1,696	1,847	1,828	1,770	1,764	1,683	1,626	1,622	1,657	1,747
DEVONIAN SHALE (BCF)	152	180	211	226	240	263	294	314	359	398	446	488
COAL BED METHANE (BCF)	103	178	286	423	552	687	797	904	1,012	1,067	1,108	1,120
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	166	177	203	213	235	266	314	359
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	51	64	72	81	87	103	132	174	222
TOTAL NON-ASSOC GAS (BCF)	14,086	14,625	14,752	15,080	15,355	15,448	15,627	15,506	15,712	15,733	15,874	16,233
TOTAL OIL (MMB)	1,871	1,782	1,751	1,723	1,712	1,683	1,666	1,672	1,669	1,659	1,652	1,653
TOTAL GAS (BCF)	16,816	17,345	17,350	17,563	17,731	17,688	17,797	17,646	17,843	17,834	17,936	18,275
TOTAL NGL (MMB)	740	752	747	758	762	750	750	744	753	755	757	768
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,857	18,823	18,614	18,377	18,064	17,677	17,209	16,750	16,381	16,141
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,701	21,023	20,487	19,940	19,405	18,834	18,289	17,887	17,658
HIGH PERMEABILITY (BCF)	105,416	105,206	100,367	95,954	92,312	89,109	86,352	84,229	82,459	80,809	80,043	79,792
LOW PERMEABILITY (BCF)	22,837	22,856	22,678	22,623	21,892	21,401	20,697	20,052	19,575	19,151	18,916	18,906
DEVONIAN SHALE (BCF)	1,751	2,076	2,264	2,365	2,465	2,649	2,882	3,184	3,567	4,047	4,572	5,001
COAL BED METHANE (BCF)	2,798	4,731	6,845	7,867	8,816	9,647	10,470	11,150	11,260	11,179	11,101	11,003
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,317	1,454	1,618	1,833	2,098	2,375	2,615	2,694
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	621	694	760	832	948	1,095	1,463	1,862	2,353
TOTAL NON-ASSOC GAS (BCF)	134,272	136,555	134,001	130,760	127,497	125,020	122,851	121,397	120,054	119,024	119,110	119,748
TOTAL OIL (MMB)	20,063	19,670	18,857	18,823	18,614	18,377	18,064	17,677	17,209	16,750	16,381	16,141
TOTAL GAS (BCF)	159,313	160,421	156,306	152,462	148,519	145,507	142,790	140,802	138,887	137,313	136,996	137,406
TOTAL NGL (MMB)	7,499	7,428	7,111	6,879	6,637	6,438	6,251	6,098	5,969	5,849	5,789	5,771
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,059	1,073	1,080	1,075	1,079	1,068	1,077	1,075	1,080	1,100

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)											Run Date: 08/16/92 Run Time: 02:04 PM			
TABLE 2: LOWER 48 WELLS AND RESERVES														
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	13,738	16,670	19,679	21,794	22,479	23,528	24,023	25,002	25,164	25,318	0	0	0	0
DEVELOPMENT WELLS	38,136	40,598	40,080	37,856	37,662	39,560	35,957	36,148	37,094	40,073	0	0	0	0
TOTAL GAS WELLS	14,322	14,195	14,282	14,500	14,384	14,388	15,280	16,178	17,085	18,400	0	0	0	0
TOTAL WELLS	51,873	57,268	59,759	59,649	60,140	63,088	59,980	61,150	62,258	65,391	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,459	1,518	1,569	1,565	1,619	1,630	1,376	1,308	1,221	1,165	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,868	1,991	2,107	2,084	2,146	2,133	1,828	1,688	1,541	1,490	0	0	0	0
HIGH PERMEABILITY (BCF)	13,229	13,515	13,996	14,356	14,024	12,885	11,939	11,160	10,943	11,035	0	0	0	0
LOW PERMEABILITY (BCF)	2,030	2,064	2,098	2,078	1,946	1,948	1,956	1,910	2,053	2,229	0	0	0	0
DEVONIAN SHALE (BCF)	886	830	644	611	518	492	470	451	467	507	0	0	0	0
COAL BED METHANE (BCF)	1,070	1,141	1,102	1,016	1,119	1,263	1,480	1,701	1,815	2,084	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	423	444	482	486	486	409	232	204	109	21	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	929	1,108	1,330	1,609	1,935	2,378	2,858	3,458	4,205	5,116	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	18,566	19,102	19,652	20,155	20,029	19,376	18,935	18,884	19,592	20,992	0	0	0	0
TOTAL OIL (MMB)	1,459	1,518	1,569	1,565	1,619	1,630	1,376	1,308	1,221	1,165	0	0	0	0
TOTAL GAS (BCF)	20,434	21,093	21,758	22,239	22,175	21,508	20,762	20,572	21,133	22,482	0	0	0	0
TOTAL NGL (MMB)	822	842	859	865	847	797	735	694	700	709	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,663	1,678	1,702	1,723	1,743	1,763	1,767	1,751	1,724	1,687	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,038	2,039	2,063	2,085	2,114	2,139	2,148	2,131	2,087	2,033	0	0	0	0
HIGH PERMEABILITY (BCF)	12,507	12,726	12,848	13,061	13,198	13,245	13,198	13,062	12,866	12,590	0	0	0	0
LOW PERMEABILITY (BCF)	1,788	1,825	1,911	1,944	1,938	1,911	1,879	1,884	1,902	1,920	0	0	0	0
DEVONIAN SHALE (BCF)	517	534	528	525	515	507	500	500	492	506	0	0	0	0
COAL BED METHANE (BCF)	1,130	1,138	1,148	1,144	1,155	1,168	1,198	1,237	1,285	1,349	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	370	367	384	400	393	388	384	367	328	286	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	279	352	442	536	663	806	970	1,182	1,444	1,767	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,590	16,943	17,261	17,611	17,863	18,025	18,129	18,232	18,317	18,417	0	0	0	0
TOTAL OIL (MMB)	1,663	1,678	1,702	1,723	1,743	1,763	1,767	1,751	1,724	1,687	0	0	0	0
TOTAL GAS (BCF)	18,628	18,981	19,324	19,696	19,977	20,164	20,277	20,364	20,404	20,450	0	0	0	0
TOTAL NGL (MMB)	778	788	799	806	811	811	804	800	793	784	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	15,936	15,776	15,644	15,486	15,362	15,229	14,838	14,396	13,893	13,371	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	17,487	17,440	17,484	17,482	17,515	17,508	17,187	16,744	16,197	15,654	0	0	0	0
HIGH PERMEABILITY (BCF)	80,514	81,303	82,452	83,746	84,572	84,212	82,953	81,051	79,128	77,573	0	0	0	0
LOW PERMEABILITY (BCF)	19,147	19,387	19,573	19,707	19,715	19,753	19,830	19,856	20,006	20,316	0	0	0	0
DEVONIAN SHALE (BCF)	5,370	5,666	5,782	5,868	5,871	5,855	5,826	5,777	5,753	5,754	0	0	0	0
COAL BED METHANE (BCF)	10,943	10,946	10,899	10,771	10,735	10,830	11,112	11,576	12,106	12,841	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,747	2,824	2,921	3,007	3,100	3,121	2,969	2,807	2,588	2,323	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	3,002	3,758	4,645	5,718	6,990	8,562	10,450	12,726	15,486	18,835	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	121,724	123,883	126,273	128,817	130,983	132,333	133,139	133,791	135,066	137,641	0	0	0	0
TOTAL OIL (MMB)	15,936	15,776	15,644	15,486	15,362	15,229	14,838	14,396	13,893	13,371	0	0	0	0
TOTAL GAS (BCF)	139,211	141,323	143,757	146,299	148,498	149,842	150,327	150,535	151,264	153,295	0	0	0	0
TOTAL NGL (MMB)	5,815	5,868	5,929	5,987	6,023	6,009	5,940	5,834	5,741	5,666	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,118	1,138	1,158	1,180	1,196	1,205	1,209	1,213	1,214	1,214	0	0	0	0

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)

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AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQISITION	1.76	1.73	1.57	1.55	1.71	1.91	2.12	2.34	2.43	2.59	2.79	3.04		
AVERAGE CITYGATE	2.75	2.73	2.53	2.46	2.59	2.77	3.01	3.25	3.35	3.54	3.78	4.04		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.35	5.53	5.76	6.02	6.12	6.32	6.55	6.81		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.48	4.65	4.88	5.14	5.23	5.43	5.67	5.94		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.92	3.13	3.41	3.70	3.85	4.08	4.41	4.68		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.65	2.77	3.00	3.29	3.58	3.68	3.88	4.14	4.42		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.33	1.51	1.69	1.90	2.11	2.23	2.38	2.56	2.79		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.78	1.97	2.21	2.41	2.52	2.61	2.78	3.01		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.09	2.29	2.53	2.68	2.74	2.82	2.99	3.22		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.63	2.77	2.96	3.21	3.46	3.56	3.75	4.00	4.28		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQISITION	3.04	2.96	2.95	2.93	2.89	2.86	2.95	3.14	3.42	3.44	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	4.03	3.93	3.90	3.86	3.79	3.74	3.83	4.03	4.34	4.34	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.79	6.67	6.62	6.55	6.47	6.40	6.49	6.68	6.99	6.99	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.93	5.81	5.77	5.71	5.63	5.57	5.66	5.86	6.18	6.17	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.65	4.53	4.48	4.42	4.34	4.29	4.40	4.63	4.98	5.00	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.40	4.28	4.23	4.18	4.10	4.04	4.13	4.33	4.65	4.64	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.80	2.76	2.76	2.75	2.73	2.73	2.84	3.05	3.34	3.38	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	3.01	3.04	3.08	3.07	3.04	3.02	3.14	3.36	3.67	3.70	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.22	3.27	3.39	3.42	3.38	3.37	3.48	3.71	4.02	4.06	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	4.26	4.16	4.13	4.09	4.01	3.96	4.05	4.26	4.58	4.59	0.00	0.00	0.00	0.00

CASE 2

**NPC Low Reference Case
No. 3 Final**

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)

Run Date: 08/20/92

Run Time: 04:04 PM

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,821	89.9	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,355	106.3	82.7	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,088	17,366	75.4	83.0	1.04	1.25
1992	17.66	1.28	1.45	1.44	42.2	13,403	17,552	76.4	85.6	1.00	1.31
1993	16.90	1.37	1.54	1.48	47.1	12,121	17,486	69.3	88.0	0.99	1.41
1994	16.17	1.49	1.66	1.57	53.3	11,961	17,246	69.4	91.1	0.98	1.55
1995	15.50	1.61	1.78	1.68	60.3	11,768	17,072	68.9	94.1	0.97	1.68
1996	15.77	1.84	2.01	1.89	67.8	12,433	16,628	74.8	94.8	0.99	1.89
1997	16.06	1.93	2.10	1.97	69.7	12,397	16,343	75.9	95.3	0.98	2.01
1998	16.36	2.10	2.26	2.14	74.4	12,776	16,171	79.0	95.6	0.97	2.21
1999	16.67	2.21	2.38	2.26	76.9	13,650	16,030	85.2	95.8	0.97	2.33
2000	17.00	2.36	2.53	2.42	80.6	15,505	16,034	96.7	95.8	0.96	2.51
2001	17.30	2.43	2.60	2.49	81.5	16,498	16,248	101.5	95.8	0.97	2.56
2002	17.59	2.44	2.60	2.50	80.3	17,367	16,591	104.7	95.9	0.98	2.54
2003	17.90	2.43	2.60	2.50	78.9	18,135	16,880	107.4	95.9	0.98	2.53
2004	18.19	2.41	2.58	2.48	77.0	18,135	17,192	105.5	95.9	0.97	2.54
2005	18.50	2.45	2.61	2.51	76.7	17,888	17,378	102.9	95.8	0.96	2.61
2006	18.79	2.51	2.68	2.57	77.5	17,476	17,354	100.7	95.7	0.95	2.70
2007	19.10	2.59	2.76	2.65	78.8	16,890	17,309	97.6	95.8	0.94	2.82
2008	19.40	2.69	2.86	2.74	80.4	17,350	17,225	100.7	95.8	0.94	2.93
2009	19.69	2.75	2.91	2.80	80.9	17,737	17,280	102.7	95.7	0.91	3.07
2010	20.00	2.74	2.91	2.78	79.6	18,320	17,369	105.5	95.7	0.90	3.09
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
DEMAND														
RESIDENTIAL	4,900	4,497	4,700	4,877	4,895	4,915	4,937	4,921	4,893	4,859	4,835	4,804		
COMMERCIAL *	2,771	2,729	2,847	2,859	2,848	2,861	2,865	2,854	2,827	2,814	2,832	2,866		
INDUSTRIAL	6,949	7,060	7,394	7,374	7,420	7,358	7,223	7,027	6,898	6,842	6,737	6,550		
BOILERS	2,791	2,831	2,985	2,903	2,910	2,885	2,822	2,707	2,613	2,577	2,510	2,391		
NONBOILERS	4,158	4,229	4,409	4,471	4,509	4,473	4,402	4,320	4,285	4,264	4,227	4,159		
ELECTRIC UTILITY	2,808	2,852	2,905	2,888	2,860	2,886	2,972	2,974	3,045	2,986	2,973	3,232		
TOTAL END USE DEMAND	17,428	17,139	17,846	17,998	18,023	18,019	17,997	17,777	17,663	17,501	17,377	17,451		
LEASE AND PLANT USE	886	1,061	1,094	1,107	1,099	1,082	1,068	1,038	1,019	1,007	998	997		
TRANSMISSION FUEL	655	644	671	677	678	678	677	668	664	658	653	656		
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547		
TOTAL DISPOSITION	19,148	19,017	19,869	20,101	20,188	20,208	20,204	19,967	19,845	19,682	19,560	19,652		
SUPPLY														
LOWER-48 PRODUCTION	17,661	17,356	17,959	18,062	17,988	17,740	17,554	17,093	16,797	16,613	16,472	16,471		
PIPELINE IMPORTS	1,327	1,466	1,709	1,835	1,995	2,257	2,417	2,534	2,655	2,603	2,540	2,505		
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0		
LNG + SNG + SUPPLEMENTALS	153	191	197	199	199	199	216	317	367	436	515	641		
TOTAL GAS SUPPLY	19,141	19,013	19,864	20,095	20,182	20,196	20,187	19,944	19,818	19,651	19,527	19,616		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,775	4,755	4,744	4,739	4,732	4,721	4,703	4,685	4,674	4,670	0	0	0	0
COMMERCIAL *	2,904	2,940	2,990	3,042	3,096	3,121	3,144	3,155	3,156	3,142	0	0	0	0
INDUSTRIAL	6,555	6,581	6,575	6,616	6,542	6,430	6,321	6,231	6,149	6,082	0	0	0	0
BOILERS	2,420	2,452	2,461	2,495	2,464	2,406	2,346	2,299	2,252	2,224	0	0	0	0
NONBOILERS	4,135	4,128	4,115	4,121	4,078	4,024	3,974	3,932	3,897	3,858	0	0	0	0
ELECTRIC UTILITY	3,431	3,687	3,866	4,070	4,226	4,382	4,516	4,648	4,776	4,936	0	0	0	0
TOTAL END USE DEMAND	17,665	17,962	18,175	18,466	18,596	18,653	18,684	18,719	18,755	18,829	0	0	0	0
LEASE AND PLANT USE	1,010	1,030	1,047	1,064	1,074	1,070	1,067	1,061	1,063	1,068	0	0	0	0
TRANSMISSION FUEL	664	675	683	694	699	701	703	704	705	708	0	0	0	0
UAF + EXPORTS	563	579	600	622	643	664	680	696	712	728	0	0	0	0
TOTAL DISPOSITION	19,902	20,246	20,505	20,846	21,012	21,089	21,133	21,179	21,235	21,333	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	16,670	17,030	17,328	17,652	17,842	17,832	17,777	17,681	17,738	17,808	0	0	0	0
PIPELINE IMPORTS	2,502	2,516	2,505	2,565	2,555	2,610	2,673	2,795	2,792	2,832	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	670	642	614	569	555	580	610	625	627	615	0	0	0	0
TOTAL GAS SUPPLY	19,841	20,187	20,447	20,785	20,951	21,022	21,060	21,100	21,157	21,255	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

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ENERGY DEMAND FOR COMBUSTION USES
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,428	17,139	17,846	17,998	18,023	18,019	17,997	17,777	17,663	17,501	17,377	17,451
RESIDUAL FUEL OIL	2,288	1,962	1,833	1,933	1,868	1,879	1,975	2,187	2,230	2,357	2,550	2,571
DISTILLATE FUEL OIL	2,989	2,641	2,557	2,589	2,602	2,602	2,590	2,573	2,564	2,559	2,549	2,522
LPG (RES/COM SECTORS)	470	429	420	428	432	433	432	430	427	423	419	414
COAL (EXCLUDES COKING COAL)	17,628	17,864	17,757	17,787	17,936	17,900	17,904	18,003	18,194	18,307	18,419	18,485
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,130	3,155	3,155	3,159	3,163	3,167	3,170	3,173
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,278	49,986	50,434	50,667	50,801	50,931	51,091	51,214	51,374	51,553	51,773
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,440	9,512	9,584	9,659	9,786	9,916	10,047	10,180	10,316
LESS ELEC UTIL ENERGY INPUT	(19,793)	(20,169)	(20,294)	(20,401)	(20,541)	(20,678)	(20,844)	(20,988)	(21,122)	(21,218)	(21,339)	(21,460)
END USE ENERGY DEMAND	38,456	38,321	39,063	39,473	39,637	39,708	39,746	39,889	40,008	40,202	40,395	40,629

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	17,665	17,962	18,175	18,466	18,596	18,653	18,684	18,719	18,755	18,829	0	0	0	0
RESIDUAL FUEL OIL	2,399	2,149	2,006	1,759	1,720	1,782	1,822	1,831	1,848	1,804	0	0	0	0
DISTILLATE FUEL OIL	2,512	2,501	2,489	2,528	2,512	2,443	2,424	2,405	2,387	2,368	0	0	0	0
LPG (RES/COM SECTORS)	410	405	400	396	392	387	383	378	374	370	0	0	0	0
COAL (EXCLUDES COKING COAL)	18,737	18,993	19,248	19,499	19,741	19,963	20,196	20,457	20,716	20,986	0	0	0	0
HYDRO/RENEWABLES	3,184	3,207	3,230	3,255	3,281	3,310	3,338	3,368	3,398	3,429	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	52,013	52,271	52,552	52,856	53,145	53,391	53,648	53,909	54,179	54,437	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,464	10,614	10,767	10,922	11,079	11,244	11,411	11,581	11,754	11,930	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(21,630)	(21,814)	(21,992)	(22,175)	(22,381)	(22,613)	(22,847)	(23,083)	(23,324)	(23,568)	0	0	0	0
END USE ENERGY DEMAND	40,846	41,072	41,327	41,603	41,843	42,021	42,212	42,407	42,610	42,799	0	0	0	0

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)											Run Date: 08/20/92	
											Run Time: 04:04 PM	
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,266	3,280	3,295	3,310	3,346	3,381	3,417	3,454	3,491
DISTILLATE OIL	1,165	898	877	901	907	905	901	894	885	873	859	845
LPG	400	364	358	363	368	369	370	368	366	363	358	354
COAL	58	62	58	61	61	60	60	60	59	59	58	58
NATURAL GAS	4,900	4,497	4,700	4,877	4,895	4,915	4,937	4,921	4,893	4,859	4,835	4,804
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,960	9,245	9,468	9,510	9,545	9,578	9,589	9,585	9,571	9,565	9,551
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,949	2,975	3,000	3,027	3,061	3,097	3,132	3,168	3,204
DISTILLATE OIL	561	518	509	522	525	526	522	520	519	516	515	518
LPG	70	65	63	65	64	63	62	62	61	61	60	61
COAL	88	94	88	94	94	94	93	91	90	90	89	89
NATURAL GAS	2,771	2,729	2,847	2,859	2,848	2,861	2,865	2,854	2,827	2,814	2,832	2,866
RESIDUAL OIL	228	226	223	220	214	210	206	201	196	191	189	187
TOTAL FUELS	6,472	6,494	6,654	6,709	6,720	6,754	6,774	6,790	6,789	6,804	6,853	6,924
INDUSTRIAL END USES *												
NATURAL GAS	6,949	7,060	7,394	7,374	7,420	7,358	7,223	7,027	6,898	6,842	6,737	6,550
HIGH SULFUR RESID	311	289	248	267	256	249	263	343	326	363	411	474
LOW SULFUR RESID	301	286	251	296	279	272	302	372	466	490	516	612
DISTILLATE	1,134	1,168	1,104	1,094	1,091	1,085	1,073	1,057	1,049	1,042	1,030	1,012
ELECTRICITY	3,135	3,212	3,195	3,226	3,257	3,289	3,322	3,379	3,438	3,498	3,559	3,621
COAL	1,640	1,641	1,601	1,600	1,593	1,572	1,552	1,546	1,541	1,545	1,544	1,570
TOTAL FUELS	13,471	13,655	13,794	13,857	13,896	13,824	13,735	13,723	13,718	13,780	13,796	13,838
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,888	2,860	2,886	2,972	2,974	3,045	2,986	2,973	3,232
HIGH SULFUR RESID	590	490	477	548	482	489	528	575	573	580	610	510
LOW SULFUR RESID	858	671	634	602	637	660	677	697	670	732	825	788
DISTILLATE	130	57	67	73	79	86	94	102	111	128	145	148
COAL	15,842	16,067	16,009	16,032	16,188	16,173	16,200	16,305	16,503	16,613	16,728	16,768
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,806	9,969	10,033	10,121	10,136	10,227	10,240	10,330
TOTAL FUELS	28,733	29,381	29,664	29,841	30,053	30,262	30,502	30,774	31,037	31,265	31,519	31,776
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,428	17,139	17,846	17,998	18,023	18,019	17,997	17,777	17,663	17,501	17,377	17,451
HIGH SULFUR RESID	901	778	725	815	738	737	791	918	899	943	1,021	984
LOW SULFUR RESID	1,387	1,184	1,108	1,119	1,130	1,142	1,184	1,270	1,332	1,414	1,529	1,587
DISTILLATE	2,989	2,641	2,557	2,589	2,602	2,602	2,590	2,573	2,564	2,559	2,549	2,522
COAL	17,628	17,864	17,757	17,787	17,936	17,900	17,904	18,003	18,194	18,307	18,419	18,485
ALL OTHER FUELS	8,975	9,672	9,993	10,127	10,238	10,402	10,465	10,551	10,563	10,650	10,658	10,744
TOTAL FUELS	49,308	49,278	49,986	50,434	50,667	50,801	50,930	51,090	51,214	51,373	51,553	51,773

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)

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LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,529	3,567	3,606	3,645	3,685	3,725	3,766	3,807	3,849	3,891	0	0	0	0
DISTILLATE OIL	830	816	802	789	776	763	750	738	727	717	0	0	0	0
LPG	349	344	340	335	331	327	323	318	315	312	0	0	0	0
COAL	58	57	57	56	56	55	55	54	54	53	0	0	0	0
NATURAL GAS	4,775	4,755	4,744	4,739	4,732	4,721	4,703	4,685	4,674	4,670	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,541	9,539	9,549	9,565	9,580	9,591	9,596	9,603	9,618	9,642	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,249	3,294	3,340	3,387	3,434	3,486	3,540	3,594	3,649	3,705	0	0	0	0
DISTILLATE OIL	522	524	526	527	530	529	529	528	526	520	0	0	0	0
LPG	61	61	61	61	61	60	60	60	59	59	0	0	0	0
COAL	90	90	90	90	90	90	90	89	89	87	0	0	0	0
NATURAL GAS	2,904	2,940	2,990	3,042	3,096	3,121	3,144	3,155	3,156	3,142	0	0	0	0
RESIDUAL OIL	186	185	185	185	185	184	183	182	180	177	0	0	0	0
TOTAL FUELS	7,011	7,093	7,191	7,291	7,396	7,470	7,546	7,608	7,658	7,689	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	6,555	6,581	6,575	6,616	6,542	6,430	6,321	6,231	6,149	6,082	0	0	0	0
HIGH SULFUR RESID	454	411	376	329	316	318	327	320	319	299	0	0	0	0
LOW SULFUR RESID	556	507	478	427	406	398	396	389	381	363	0	0	0	0
DISTILLATE	1,009	1,009	1,006	1,007	999	988	978	969	961	954	0	0	0	0
ELECTRICITY	3,686	3,753	3,821	3,890	3,960	4,032	4,106	4,180	4,257	4,334	0	0	0	0
COAL	1,570	1,565	1,564	1,557	1,564	1,550	1,533	1,526	1,514	1,506	0	0	0	0
TOTAL FUELS	13,831	13,825	13,820	13,825	13,787	13,716	13,659	13,615	13,580	13,538	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	3,431	3,687	3,866	4,070	4,226	4,382	4,516	4,648	4,776	4,936	0	0	0	0
HIGH SULFUR RESID	497	466	435	336	327	375	400	409	415	406	0	0	0	0
LOW SULFUR RESID	705	580	532	482	486	507	516	532	554	560	0	0	0	0
DISTILLATE	151	152	155	204	207	163	167	170	173	177	0	0	0	0
COAL	17,020	17,282	17,537	17,797	18,031	18,269	18,519	18,787	19,060	19,339	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,291	10,262	10,235	10,208	10,184	10,162	10,140	10,120	10,100	10,080	0	0	0	0
TOTAL FUELS	32,094	32,428	32,759	33,097	33,460	33,857	34,258	34,664	35,078	35,498	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	17,665	17,962	18,175	18,466	18,596	18,653	18,684	18,719	18,755	18,829	0	0	0	0
HIGH SULFUR RESID	951	877	811	665	642	693	727	728	734	704	0	0	0	0
LOW SULFUR RESID	1,448	1,272	1,195	1,094	1,077	1,089	1,095	1,102	1,114	1,100	0	0	0	0
DISTILLATE	2,512	2,501	2,489	2,528	2,512	2,443	2,424	2,405	2,387	2,368	0	0	0	0
COAL	18,737	18,993	19,248	19,499	19,741	19,963	20,196	20,457	20,716	20,986	0	0	0	0
ALL OTHER FUELS	10,700	10,667	10,635	10,604	10,576	10,549	10,523	10,498	10,474	10,450	0	0	0	0
TOTAL FUELS	52,013	52,271	52,551	52,856	53,144	53,390	53,648	53,908	54,179	54,437	0	0	0	0

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)						TABLE 2: LOWER 48 WELLS AND RESERVES				Run Date: 08/20/92 Run Time: 04:04 PM		
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,536	4,584	3,961	3,699	3,788	4,126	4,417	4,874	6,088	7,630
DEVELOPMENT WELLS	22,582	27,158	26,372	21,033	18,281	17,183	17,728	18,361	17,303	17,298	21,674	26,218
TOTAL GAS WELLS	9,472	10,333	9,829	7,426	6,677	6,881	6,714	7,439	7,432	7,788	7,714	9,145
TOTAL WELLS	28,326	33,314	31,907	25,618	22,243	20,882	21,517	22,487	21,720	22,172	27,763	33,849
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	938	1,647	1,392	1,107	976	974	905	915	1,074	1,164
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,015	1,838	1,562	1,250	1,135	1,150	1,163	1,181	1,384	1,470
HIGH PERMEABILITY (BCF)	9,905	12,223	7,433	7,719	7,454	7,876	7,836	8,568	8,954	9,086	9,228	10,619
LOW PERMEABILITY (BCF)	1,339	1,691	1,497	1,740	1,022	817	681	696	723	926	1,238	1,405
DEVONIAN SHALE (BCF)	384	504	399	326	340	363	395	422	488	638	712	678
COAL BED METHANE (BCF)	1,607	2,111	2,400	1,446	1,449	1,416	1,472	1,339	774	581	620	599
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	152	143	145	154	178	214	264	466
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	151	140	97	104	103	116	149	203	267
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,073	11,564	10,559	10,711	10,632	11,283	11,234	11,594	12,266	14,035
TOTAL OIL (MMB)	1,194	1,388	938	1,647	1,392	1,107	976	974	905	915	1,074	1,164
TOTAL GAS (BCF)	15,127	18,454	13,088	13,403	12,121	11,961	11,768	12,433	12,397	12,776	13,650	15,505
TOTAL NGL (MMB)	550	681	429	512	458	442	418	466	490	509	549	640
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,721	1,702	1,647	1,589	1,559	1,531	1,502	1,484	1,477
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,481	2,365	2,199	2,080	2,005	1,959	1,903	1,848	1,813
HIGH PERMEABILITY (BCF)	12,041	12,440	12,388	12,362	12,313	12,164	12,049	11,673	11,443	11,270	11,067	11,006
LOW PERMEABILITY (BCF)	1,666	1,675	1,699	1,845	1,790	1,713	1,643	1,558	1,455	1,448	1,494	1,529
DEVONIAN SHALE (BCF)	152	180	211	226	239	256	278	286	304	327	355	386
COAL BED METHANE (BCF)	103	178	285	423	550	681	785	881	970	1,003	1,017	1,000
ENHANCED RECOVERY GAS (BCF)	83	114	138	162	163	163	163	150	134	138	160	195
ENHANCED RECOVERY TIGHT (BCF)	47	48	48	52	65	71	74	74	78	82	89	104
TOTAL NON-ASSOC GAS (BCF)	14,091	14,634	14,768	15,071	15,121	15,047	14,991	14,622	14,383	14,268	14,182	14,221
TOTAL OIL (MMB)	1,871	1,782	1,751	1,721	1,702	1,647	1,589	1,559	1,531	1,502	1,484	1,477
TOTAL GAS (BCF)	16,821	17,355	17,386	17,552	17,486	17,246	17,072	16,628	16,343	16,171	16,030	16,034
TOTAL NGL (MMB)	740	752	748	757	752	734	723	701	691	686	681	678
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,857	18,782	18,472	17,932	17,319	16,734	16,108	15,521	15,111	14,797
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,662	20,860	19,910	18,965	18,110	17,314	16,592	16,129	15,786
HIGH PERMEABILITY (BCF)	105,413	105,196	100,343	95,701	90,842	86,554	82,342	79,236	76,748	74,563	72,724	72,337
LOW PERMEABILITY (BCF)	22,835	22,851	22,671	22,566	21,798	20,902	19,939	19,077	18,346	17,825	17,569	17,445
DEVONIAN SHALE (BCF)	1,751	2,076	2,264	2,364	2,465	2,572	2,689	2,826	3,010	3,320	3,677	3,970
COAL BED METHANE (BCF)	2,798	4,731	6,845	7,868	8,767	9,502	10,188	10,647	10,451	10,030	9,632	9,231
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,310	1,330	1,319	1,298	1,280	1,285	1,329	1,405	1,509	1,780
ENHANCED RECOVERY TIGHT (BCF)	506	535	538	635	710	736	766	795	834	901	1,015	1,178
TOTAL NON-ASSOC GAS (BCF)	134,266	136,540	133,969	130,463	125,901	121,564	117,205	113,866	110,716	108,043	106,126	105,941
TOTAL OIL (MMB)	20,083	19,670	18,857	18,782	18,472	17,932	17,319	16,734	16,108	15,521	15,111	14,797
TOTAL GAS (BCF)	159,307	160,406	156,275	152,125	146,760	141,475	136,171	131,976	128,031	124,835	122,255	121,726
TOTAL NGL (MMB)	7,499	7,429	7,111	6,865	6,570	6,279	5,974	5,739	5,538	5,361	5,229	5,191
LEASE AND PLANT GAS (BCF)												
	857	1,027	1,060	1,072	1,065	1,048	1,035	1,006	987	976	967	966

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)											Run Date: 08/20/92 Run Time: 04:04 PM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	9,242	10,930	11,339	12,158	12,921	13,193	14,136	14,410	15,665	16,182	0	0	0	0
DEVELOPMENT WELLS	28,972	30,539	31,298	32,009	34,275	33,240	33,225	27,578	29,112	30,545	0	0	0	0
TOTAL GAS WELLS	10,291	11,535	12,595	12,479	12,456	12,281	12,165	11,902	11,986	12,209	0	0	0	0
TOTAL WELLS	38,214	41,469	42,637	44,167	47,197	46,434	47,361	41,988	44,778	46,727	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,231	1,280	1,317	1,291	1,305	1,271	1,294	1,037	1,053	1,041	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,564	1,642	1,699	1,716	1,701	1,615	1,627	1,337	1,373	1,371	0	0	0	0
HIGH PERMEABILITY (BCF)	11,353	11,826	12,094	11,875	11,549	11,243	10,871	11,059	11,051	11,118	0	0	0	0
LOW PERMEABILITY (BCF)	1,512	1,609	1,546	1,438	1,415	1,439	1,554	1,854	1,851	1,985	0	0	0	0
DEVONIAN SHALE (BCF)	680	797	921	934	824	728	453	254	201	133	0	0	0	0
COAL BED METHANE (BCF)	482	461	480	584	667	695	763	922	1,080	1,141	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	570	626	717	792	800	643	260	186	88	6	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	338	405	679	795	933	1,113	1,363	1,738	2,092	2,566	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	14,934	15,724	16,436	16,418	16,187	15,861	15,264	16,013	16,364	16,949	0	0	0	0
TOTAL OIL (MMB)	1,231	1,280	1,317	1,291	1,305	1,271	1,294	1,037	1,053	1,041	0	0	0	0
TOTAL GAS (BCF)	16,498	17,367	18,135	18,135	17,888	17,476	16,890	17,350	17,737	18,320	0	0	0	0
TOTAL NGL (MMB)	698	731	745	737	713	688	651	641	630	634	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,477	1,482	1,492	1,501	1,509	1,512	1,511	1,502	1,481	1,461	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,798	1,784	1,791	1,798	1,812	1,809	1,806	1,790	1,755	1,724	0	0	0	0
HIGH PERMEABILITY (BCF)	11,136	11,331	11,489	11,650	11,716	11,641	11,560	11,467	11,438	11,414	0	0	0	0
LOW PERMEABILITY (BCF)	1,568	1,635	1,664	1,676	1,664	1,631	1,607	1,616	1,652	1,692	0	0	0	0
DEVONIAN SHALE (BCF)	409	435	468	509	535	545	536	492	457	426	0	0	0	0
COAL BED METHANE (BCF)	975	943	912	889	871	840	840	834	860	887	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	235	310	361	413	462	500	487	445	403	350	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	126	153	195	256	319	387	473	581	715	876	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	14,450	14,808	15,090	15,394	15,566	15,544	15,503	15,434	15,525	15,645	0	0	0	0
TOTAL OIL (MMB)	1,477	1,482	1,492	1,501	1,509	1,512	1,511	1,502	1,481	1,461	0	0	0	0
TOTAL GAS (BCF)	16,248	16,591	16,880	17,192	17,378	17,354	17,309	17,225	17,280	17,369	0	0	0	0
TOTAL NGL (MMB)	686	700	710	719	725	720	715	704	698	693	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	14,551	14,349	14,173	13,963	13,759	13,518	13,301	12,836	12,408	11,989	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	15,551	15,410	15,319	15,237	15,126	14,932	14,752	14,299	13,917	13,564	0	0	0	0
HIGH PERMEABILITY (BCF)	72,554	73,049	73,654	73,878	73,711	73,313	72,625	72,217	71,830	71,534	0	0	0	0
LOW PERMEABILITY (BCF)	17,389	17,362	17,244	17,005	16,757	16,565	16,512	16,750	16,950	17,243	0	0	0	0
DEVONIAN SHALE (BCF)	4,241	4,603	5,056	5,482	5,771	5,954	5,870	5,632	5,376	5,083	0	0	0	0
COAL BED METHANE (BCF)	8,737	8,255	7,823	7,518	7,313	7,169	7,092	7,180	7,401	7,655	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,115	2,430	2,786	3,165	3,503	3,646	3,418	3,159	2,845	2,501	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	1,390	1,642	2,126	2,664	3,278	4,004	4,893	6,050	7,427	9,117	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	106,425	107,342	108,688	109,713	110,334	110,650	110,410	110,989	111,828	113,132	0	0	0	0
TOTAL OIL (MMB)	14,551	14,349	14,173	13,963	13,759	13,518	13,301	12,836	12,408	11,989	0	0	0	0
TOTAL GAS (BCF)	121,977	122,752	124,007	124,949	125,460	125,582	125,162	125,288	125,745	126,696	0	0	0	0
TOTAL NGL (MMB)	5,203	5,233	5,267	5,285	5,274	5,242	5,177	5,115	5,047	4,988	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	978	997	1,014	1,030	1,040	1,037	1,033	1,028	1,030	1,035	0	0	0	0

NPCLREF3: NPC LOW REFERENCE CASE NO. 3 FINAL (#5)

Run Date: 08/20/92

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AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	1.76	1.73	1.57	1.51	1.55	1.65	1.74	1.98	2.06	2.23	2.37	2.55		
AVERAGE CITYGATE	2.75	2.73	2.53	2.42	2.44	2.53	2.64	2.91	3.04	3.24	3.40	3.59		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.17	5.19	5.29	5.41	5.72	5.86	6.09	6.27	6.48		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.29	4.31	4.41	4.52	4.82	4.95	5.18	5.35	5.56		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.70	2.75	2.88	3.03	3.36	3.60	3.86	4.02	4.20		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.59	2.61	2.76	2.94	3.24	3.37	3.59	3.76	3.94		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.28	1.35	1.45	1.54	1.76	1.83	1.99	2.10	2.28		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.55	1.62	1.74	1.83	1.98	2.05	2.20	2.32	2.47		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.85	1.92	2.04	2.04	2.16	2.23	2.39	2.51	2.65		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.59	2.61	2.70	2.82	3.10	3.23	3.44	3.61	3.80		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	2.63	2.64	2.64	2.60	2.63	2.69	2.77	2.87	2.92	2.92	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.68	3.68	3.67	3.61	3.63	3.69	3.77	3.87	3.92	3.91	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.57	6.58	6.56	6.49	6.51	6.58	6.67	6.78	6.84	6.83	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.66	5.66	5.65	5.59	5.60	5.67	5.76	5.86	5.92	5.92	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.29	4.27	4.24	4.18	4.19	4.26	4.36	4.47	4.53	4.53	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.03	4.04	4.01	3.94	3.95	4.01	4.10	4.20	4.25	4.23	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.33	2.34	2.35	2.33	2.36	2.43	2.51	2.60	2.66	2.66	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.54	2.55	2.56	2.54	2.58	2.64	2.72	2.81	2.86	2.87	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	2.71	2.73	2.74	2.72	2.76	2.83	2.91	3.00	3.06	3.06	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	3.90	3.90	3.89	3.83	3.84	3.91	3.99	4.10	4.15	4.14	0.00	0.00	0.00	0.00

CASE 3

NPC Upside Option Case Versus High Reference Case

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/06/92

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ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,814	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,341	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,211	17,345	76.2	82.8	1.02	1.27
1992	18.46	1.32	1.49	1.47	41.5	13,790	17,572	78.5	85.5	0.99	1.36
1993	18.60	1.52	1.69	1.63	47.3	13,898	17,746	78.3	88.4	0.98	1.58
1994	18.76	1.71	1.88	1.79	52.9	15,194	17,708	85.8	91.0	0.98	1.78
1995	19.01	1.91	2.07	1.97	58.2	15,585	17,826	87.4	93.1	1.00	1.96
1996	19.25	2.15	2.32	2.19	64.7	15,916	17,777	89.5	93.8	1.02	2.14
1997	19.56	2.26	2.43	2.29	66.9	16,023	17,935	89.3	94.4	1.02	2.25
1998	19.91	2.44	2.61	2.47	71.2	16,754	18,071	92.7	95.1	1.01	2.46
1999	20.51	2.62	2.79	2.66	74.2	18,236	18,208	100.2	95.4	1.01	2.64
2000	21.10	2.84	3.00	2.88	78.0	19,926	18,602	107.1	95.7	1.01	2.86
2001	21.75	2.77	2.94	2.82	73.8	21,557	19,074	113.0	95.4	1.01	2.79
2002	22.55	2.78	2.94	2.82	71.4	21,713	19,561	111.0	95.1	1.00	2.83
2003	23.45	2.70	2.87	2.74	66.8	23,175	19,899	116.5	94.3	0.99	2.78
2004	24.25	2.62	2.79	2.65	62.6	23,476	20,281	115.8	93.5	0.99	2.70
2005	25.14	2.63	2.80	2.65	60.6	23,691	20,679	114.6	93.1	0.98	2.74
2006	25.74	2.48	2.65	2.50	56.0	23,026	20,733	111.1	91.7	0.97	2.61
2007	26.25	2.67	2.84	2.68	58.9	22,172	21,025	105.5	92.4	0.96	2.84
2008	26.75	2.73	2.90	2.72	59.3	22,492	21,126	106.5	92.5	0.95	2.94
2009	27.35	2.90	3.07	2.87	61.5	22,798	21,315	107.0	93.1	0.94	3.16
2010	27.85	2.99	3.16	2.96	62.3	23,357	21,403	109.1	93.1	0.93	3.29
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/06/92

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DEMAND												
RESIDENTIAL	4,900	4,498	4,700	4,853	4,854	4,861	4,894	4,901	4,902	4,898	4,894	4,884
COMMERCIAL *	2,772	2,730	2,846	2,851	2,851	2,867	2,899	2,937	2,972	3,022	3,103	3,207
INDUSTRIAL	6,939	7,046	7,376	7,415	7,643	7,771	7,848	7,827	7,853	7,916	7,910	7,989
BOILERS	2,792	2,831	2,983	2,925	3,009	3,079	3,128	3,136	3,137	3,166	3,170	3,172
NONBOILERS	4,148	4,215	4,393	4,490	4,634	4,692	4,720	4,891	4,716	4,750	4,741	4,797
ELECTRIC UTILITY	2,808	2,852	2,905	2,897	2,902	2,926	3,055	3,154	3,349	3,464	3,609	3,880
TOTAL END USE DEMAND	17,419	17,126	17,827	18,015	18,250	18,426	18,695	18,819	19,076	19,300	19,517	19,940
LEASE AND PLANT USE	886	1,060	1,093	1,108	1,116	1,111	1,117	1,111	1,119	1,126	1,132	1,155
TRANSMISSION FUEL	655	644	670	677	686	693	703	708	717	726	734	750
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547
TOTAL DISPOSITION	19,138	19,002	19,848	20,120	20,440	20,660	20,977	21,121	21,411	21,667	21,914	22,392
SUPPLY												
LOWER-48 PRODUCTION	17,652	17,342	17,938	18,080	18,258	18,211	18,331	18,279	18,444	18,579	18,735	19,146
PIPELINE IMPORTS	1,327	1,465	1,709	1,838	1,965	2,204	2,389	2,506	2,587	2,600	2,634	2,643
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	243	318	360	466	521	577
TOTAL GAS SUPPLY	19,131	18,998	19,844	20,114	20,434	20,649	20,962	21,103	21,391	21,645	21,889	22,366

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,879	4,898	4,901	4,920	4,938	4,945	4,961	4,965	4,991	5,021	0	0	0	0
COMMERCIAL *	3,347	3,501	3,652	3,812	3,974	4,105	4,253	4,380	4,510	4,619	0	0	0	0
INDUSTRIAL	8,214	8,382	8,454	8,589	8,714	8,845	8,970	9,009	9,171	9,291	0	0	0	0
BOILERS	3,329	3,432	3,496	3,582	3,655	3,733	3,798	3,832	3,920	3,988	0	0	0	0
NONBOILERS	4,885	4,950	4,957	5,006	5,059	5,113	5,173	5,177	5,252	5,303	0	0	0	0
ELECTRIC UTILITY	4,045	4,176	4,273	4,379	4,530	4,652	4,839	4,982	5,141	5,309	0	0	0	0
TOTAL END USE DEMAND	20,485	20,957	21,280	21,700	22,156	22,547	23,023	23,336	23,813	24,241	0	0	0	0
LEASE AND PLANT USE	1,183	1,212	1,232	1,258	1,280	1,281	1,298	1,302	1,312	1,315	0	0	0	0
TRANSMISSION FUEL	770	788	800	816	833	848	866	877	895	912	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,954	23,441	23,764	24,192	24,657	25,016	25,479	25,798	26,303	26,665	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,852	20,131	20,476	20,886	21,323	21,379	21,696	21,806	21,999	22,078	0	0	0	0
PIPELINE IMPORTS	2,745	2,829	2,865	2,911	2,942	3,246	3,391	3,599	3,905	4,187	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	533	466	416	388	384	383	383	382	383	383	0	0	0	0
TOTAL GAS SUPPLY	22,930	23,426	23,757	24,184	24,649	25,008	25,470	25,787	26,287	26,647	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/06/92

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ENERGY DEMAND FOR COMBUSTION USES

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,419	17,126	17,827	18,015	18,250	18,426	18,695	18,819	19,076	19,300	19,517	19,940
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,945	1,865	1,898	1,925	2,054	2,038	2,041	2,103	2,101
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,612	2,624	2,626	2,622	2,624	2,630	2,630	2,617
LPG (RES/COM SECTORS)	470	429	420	426	428	427	426	424	421	418	414	410
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,869	18,077	18,136	18,218	18,359	18,604	18,792	19,002	19,151
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,217	3,223
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,277	49,986	50,542	51,041	51,483	51,926	52,440	52,942	53,452	53,952	54,600
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,472	9,575	9,679	9,784	9,940	10,104	10,267	10,429	10,602
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,910)	(30,187)	(30,461)	(30,764)	(31,132)	(31,522)	(31,856)	(32,194)	(32,548)
END USE ENERGY DEMAND	29,516	29,108	29,693	30,103	30,430	30,701	30,946	31,247	31,524	31,863	32,187	32,653

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	20,485	20,957	21,280	21,700	22,156	22,547	23,023	23,336	23,813	24,241	0	0	0	0
RESIDUAL FUEL OIL	1,839	1,809	1,753	1,733	1,730	1,722	1,778	1,783	1,821	1,844	0	0	0	0
DISTILLATE FUEL OIL	2,628	2,634	2,627	2,630	2,635	2,638	2,645	2,642	2,649	2,651	0	0	0	0
LPG (RES/COM SECTORS)	406	403	398	395	393	389	387	384	382	381	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,441	19,845	20,213	20,595	20,921	21,281	21,595	21,921	22,255	22,622	0	0	0	0
HYDRO/RENEWABLES	3,242	3,270	3,300	3,331	3,361	3,392	3,424	3,457	3,489	3,523	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	55,147	55,974	56,575	57,338	58,099	58,821	59,654	60,275	61,111	61,914	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,752	10,950	11,121	11,292	11,468	11,649	11,850	12,036	12,234	12,445	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(32,870)	(33,342)	(33,736)	(34,157)	(34,584)	(35,039)	(35,537)	(35,996)	(36,505)	(37,053)	0	0	0	0
END USE ENERGY DEMAND	33,029	33,581	33,960	34,472	34,982	35,431	35,968	36,314	36,840	37,306	0	0	0	0

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)										Run Date: 09/06/92		
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LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,400	3,454	3,512	3,569	3,628	3,689
DISTILLATE OIL	1,165	898	877	897	899	892	885	877	867	856	843	830
LPG	400	364	358	361	363	363	362	360	358	355	351	347
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,498	4,700	4,853	4,854	4,861	4,894	4,901	4,902	4,898	4,894	4,884
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,961	9,245	9,459	9,500	9,538	9,601	9,652	9,698	9,738	9,775	9,809
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,954	2,983	3,013	3,042	3,081	3,121	3,158	3,194	3,228
DISTILLATE OIL	561	518	509	521	526	527	524	523	521	519	518	521
LPG	70	65	63	65	64	65	64	64	63	63	63	63
COAL	88	94	88	94	94	95	94	94	93	92	92	92
NATURAL GAS	2,772	2,730	2,846	2,851	2,851	2,867	2,899	2,937	2,972	3,022	3,103	3,207
RESIDUAL OIL	228	226	223	220	214	210	207	203	199	195	193	192
TOTAL FUELS	6,472	6,494	6,653	6,704	6,734	6,776	6,830	6,902	6,970	7,050	7,162	7,302
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,415	7,643	7,771	7,848	7,827	7,853	7,916	7,910	7,969
HIGH SULFUR RESID	311	288	249	268	253	252	238	275	253	272	295	322
LOW SULFUR RESID	301	286	252	299	273	283	288	359	424	449	478	540
DISTILLATE	1,133	1,167	1,103	1,097	1,109	1,118	1,122	1,119	1,124	1,125	1,122	1,118
ELECTRICITY	3,135	3,212	3,195	3,231	3,267	3,304	3,342	3,404	3,471	3,540	3,607	3,685
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,678	1,708	1,731	1,773	1,837	1,908
TOTAL FUELS	13,471	13,653	13,794	13,940	14,195	14,386	14,515	14,693	14,855	15,075	15,249	15,543
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,897	2,902	2,926	3,055	3,154	3,349	3,464	3,609	3,880
HIGH SULFUR RESID	590	490	477	557	468	490	477	550	544	546	553	486
LOW SULFUR RESID	858	671	634	603	656	663	716	666	618	579	584	562
DISTILLATE	130	57	67	73	79	87	95	103	112	129	146	149
COAL	15,842	16,067	16,009	16,084	16,272	16,323	16,386	16,497	16,721	16,867	17,015	17,091
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,287	10,381
TOTAL FUELS	28,733	29,381	29,664	29,910	30,187	30,461	30,764	31,132	31,522	31,856	32,194	32,548
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,419	17,126	17,827	18,015	18,250	18,426	18,695	18,819	19,076	19,300	19,517	19,940
HIGH SULFUR RESID	901	778	726	824	721	742	715	826	797	818	848	809
LOW SULFUR RESID	1,386	1,183	1,109	1,121	1,144	1,156	1,211	1,229	1,241	1,223	1,255	1,292
DISTILLATE	2,988	2,640	2,556	2,588	2,612	2,624	2,626	2,622	2,624	2,630	2,630	2,617
COAL	17,640	17,878	17,775	17,869	18,077	18,136	18,218	18,359	18,604	18,792	19,002	19,151
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,237	10,400	10,462	10,586	10,601	10,690	10,700	10,791
TOTAL FUELS	49,308	49,277	49,986	50,541	51,041	51,483	51,926	52,439	52,942	53,452	53,952	54,600

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)											Run Date: 09/06/92			
											Run Time: 01:32 PM			
LOWER 48 ENERGY DEMAND														
(Trillion Btus)														
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,747	3,809	3,873	3,935	3,997	4,061	4,126	4,193	4,258	4,325	0	0	0	0
DISTILLATE OIL	816	803	788	775	764	752	742	731	723	715	0	0	0	0
LPG	343	340	334	331	327	324	321	317	315	314	0	0	0	0
COAL	59	58	58	58	58	57	57	57	57	57	0	0	0	0
NATURAL GAS	4,879	4,898	4,901	4,920	4,938	4,945	4,961	4,965	4,991	5,021	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,843	9,908	9,954	10,019	10,084	10,140	10,208	10,263	10,343	10,431	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,258	3,292	3,328	3,361	3,394	3,429	3,464	3,501	3,536	3,573	0	0	0	0
DISTILLATE OIL	525	529	530	534	541	543	548	550	552	551	0	0	0	0
LPG	63	64	64	64	65	66	66	67	67	67	0	0	0	0
COAL	93	94	95	96	97	97	98	98	99	99	0	0	0	0
NATURAL GAS	3,347	3,501	3,652	3,812	3,974	4,105	4,253	4,380	4,510	4,619	0	0	0	0
RESIDUAL OIL	192	192	193	193	195	194	195	194	194	193	0	0	0	0
TOTAL FUELS	7,478	7,671	7,860	8,059	8,265	8,433	8,624	8,790	8,958	9,103	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	8,214	8,382	8,454	8,589	8,714	8,845	8,970	9,009	9,171	9,291	0	0	0	0
HIGH SULFUR RESID	230	220	203	202	202	198	202	199	199	197	0	0	0	0
LOW SULFUR RESID	458	440	414	403	395	383	404	394	392	383	0	0	0	0
DISTILLATE	1,137	1,146	1,151	1,159	1,166	1,175	1,183	1,185	1,195	1,201	0	0	0	0
ELECTRICITY	3,747	3,849	3,921	3,997	4,077	4,159	4,260	4,342	4,440	4,547	0	0	0	0
COAL	1,923	1,964	2,004	2,046	2,079	2,098	2,117	2,132	2,142	2,151	0	0	0	0
TOTAL FUELS	15,708	16,003	16,147	16,394	16,633	16,858	17,136	17,262	17,539	17,771	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,045	4,176	4,273	4,379	4,530	4,652	4,839	4,982	5,141	5,309	0	0	0	0
HIGH SULFUR RESID	364	353	339	336	338	338	340	340	345	349	0	0	0	0
LOW SULFUR RESID	595	604	604	600	602	609	638	655	691	722	0	0	0	0
DISTILLATE	152	155	159	162	165	168	172	176	180	184	0	0	0	0
COAL	17,367	17,729	18,057	18,397	18,687	19,028	19,323	19,634	19,957	20,316	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,348	10,326	10,304	10,284	10,264	10,244	10,226	10,209	10,191	10,174	0	0	0	0
TOTAL FUELS	32,870	33,342	33,736	34,157	34,584	35,039	35,537	35,996	36,505	37,053	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	20,485	20,957	21,280	21,700	22,156	22,547	23,023	23,336	23,813	24,241	0	0	0	0
HIGH SULFUR RESID	594	574	542	537	539	536	541	539	544	546	0	0	0	0
LOW SULFUR RESID	1,245	1,236	1,211	1,196	1,191	1,186	1,237	1,244	1,277	1,298	0	0	0	0
DISTILLATE	2,628	2,634	2,627	2,630	2,635	2,638	2,645	2,642	2,649	2,651	0	0	0	0
COAL	19,441	19,845	20,213	20,595	20,921	21,281	21,595	21,921	22,255	22,622	0	0	0	0
ALL OTHER FUELS	10,754	10,729	10,702	10,679	10,656	10,633	10,613	10,593	10,574	10,555	0	0	0	0
TOTAL FUELS	55,146	55,974	56,575	57,337	58,099	58,821	59,654	60,274	61,111	61,913	0	0	0	0

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4) TABLE 2: LOWER 48 WELLS AND RESERVES										Run Date: 09/06/92		
Run Time: 01:32 PM												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,578	4,838	4,745	5,723	6,388	6,726	7,947	8,850	10,085	12,270
DEVELOPMENT WELLS	22,582	27,158	26,428	22,540	22,987	27,384	30,595	30,564	33,031	32,538	35,067	38,791
TOTAL GAS WELLS	9,472	10,333	9,905	7,648	7,621	8,722	9,804	10,274	10,741	11,438	12,219	13,040
TOTAL WELLS	28,326	33,314	32,005	27,378	27,732	33,107	36,983	37,290	40,978	41,388	45,152	51,061
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	937	1,709	1,603	1,468	1,354	1,306	1,302	1,262	1,414	1,502
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,014	1,916	1,835	1,737	1,633	1,621	1,690	1,647	1,826	1,938
HIGH PERMEABILITY (BCF)	9,905	12,223	7,503	7,956	8,788	9,840	10,326	10,528	10,730	11,247	11,762	12,745
LOW PERMEABILITY (BCF)	1,339	1,691	1,535	1,790	1,098	1,308	1,114	1,056	1,186	1,227	1,465	1,960
DEVONIAN SHALE (BCF)	384	504	401	329	345	460	541	632	761	910	1,014	968
COAL BED METHANE (BCF)	1,607	2,111	2,413	1,462	1,526	1,555	1,655	1,561	1,031	908	997	965
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	153	143	156	325	387	495	593	663
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	152	154	150	162	192	237	320	580	688
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,197	11,873	12,064	13,457	13,952	14,295	14,332	15,107	16,410	17,988
TOTAL OIL (MMB)	1,194	1,388	937	1,709	1,603	1,468	1,354	1,306	1,302	1,262	1,414	1,502
TOTAL GAS (BCF)	15,127	18,454	13,211	13,790	13,898	15,194	15,585	15,916	16,023	16,754	18,236	19,926
TOTAL NGL (MMB)	550	681	435	528	526	571	582	603	634	665	728	799
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,725	1,721	1,700	1,683	1,688	1,690	1,689	1,691	1,702
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,485	2,387	2,261	2,192	2,161	2,157	2,137	2,110	2,099
HIGH PERMEABILITY (BCF)	12,035	12,429	12,369	12,371	12,505	12,475	12,526	12,450	12,489	12,483	12,438	12,580
LOW PERMEABILITY (BCF)	1,665	1,673	1,698	1,851	1,828	1,777	1,760	1,684	1,628	1,650	1,685	1,772
DEVONIAN SHALE (BCF)	152	180	211	226	241	264	295	321	365	405	454	499
COAL BED METHANE (BCF)	103	178	286	424	553	691	803	910	1,017	1,069	1,105	1,113
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	165	166	165	159	176	206	261	334
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	52	67	76	85	91	104	121	154	206
TOTAL NON-ASSOC GAS (BCF)	14,085	14,621	14,747	15,087	15,359	15,447	15,634	15,616	15,778	15,934	16,098	16,503
TOTAL OIL (MMB)	1,871	1,782	1,751	1,725	1,721	1,700	1,683	1,688	1,690	1,689	1,691	1,702
TOTAL GAS (BCF)	16,814	17,341	17,345	17,572	17,746	17,708	17,826	17,777	17,935	18,071	18,208	18,602
TOTAL NGL (MMB)	739	751	747	758	762	752	751	748	755	765	770	782
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,855	18,839	18,721	18,489	18,160	17,779	17,391	16,965	16,687	16,488
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,736	21,183	20,660	20,102	19,562	19,095	18,605	18,321	18,160
HIGH PERMEABILITY (BCF)	105,428	105,222	100,458	96,045	92,328	89,694	87,493	85,571	83,813	82,577	81,900	82,065
LOW PERMEABILITY (BCF)	22,837	22,855	22,715	22,653	21,923	21,455	20,809	20,181	19,739	19,316	19,095	19,284
DEVONIAN SHALE (BCF)	1,751	2,076	2,266	2,369	2,474	2,670	2,916	3,227	3,624	4,129	4,688	5,157
COAL BED METHANE (BCF)	2,798	4,731	6,858	7,896	8,868	9,733	10,584	11,235	11,249	11,088	10,979	10,831
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,318	1,296	1,286	1,452	1,664	1,952	2,285	2,613
ENHANCED RECOVERY TIGHT (BCF)	506	535	537	636	724	798	876	976	1,109	1,308	1,734	2,216
TOTAL NON-ASSOC GAS (BCF)	134,283	136,571	134,145	130,931	127,636	125,646	123,964	122,643	121,197	120,370	120,682	122,166
TOTAL OIL (MMB)	20,063	19,670	18,855	18,839	18,721	18,489	18,160	17,779	17,391	16,965	16,687	16,488
TOTAL GAS (BCF)	159,324	160,437	156,450	152,667	148,819	146,306	144,066	142,205	140,292	138,975	139,003	140,327
TOTAL NGL (MMB)	7,500	7,430	7,118	6,888	6,651	6,471	6,302	6,157	6,035	5,935	5,893	5,911
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,058	1,073	1,081	1,076	1,082	1,076	1,084	1,090	1,097	1,119

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4) TABLE 2: LOWER 48 WELLS AND RESERVES											Run Date: 09/06/92 Run Time: 01:32 PM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	14,717	16,958	20,902	23,223	24,231	24,957	26,504	28,452	29,117	27,015	0	0	0	0
DEVELOPMENT WELLS	41,201	38,578	43,903	41,441	40,504	38,498	37,153	37,727	39,449	39,845	0	0	0	0
TOTAL GAS WELLS	14,616	14,347	14,477	14,622	14,662	14,774	15,545	16,684	17,715	18,615	0	0	0	0
TOTAL WELLS	55,918	55,536	64,805	64,664	64,735	63,455	63,657	66,180	68,566	66,860	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,532	1,526	1,712	1,751	1,818	1,688	1,524	1,457	1,362	1,190	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,011	2,032	2,252	2,313	2,407	2,241	2,029	1,896	1,745	1,540	0	0	0	0
HIGH PERMEABILITY (BCF)	13,910	14,035	14,979	15,139	14,967	13,949	12,791	12,447	11,841	11,240	0	0	0	0
LOW PERMEABILITY (BCF)	2,222	2,252	2,508	2,359	2,217	2,278	2,272	2,291	2,364	2,452	0	0	0	0
DEVONIAN SHALE (BCF)	933	888	696	660	565	538	517	500	519	556	0	0	0	0
COAL BED METHANE (BCF)	932	953	940	901	1,103	1,259	1,387	1,553	1,842	2,117	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	695	520	472	474	476	400	227	202	105	21	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	854	1,032	1,327	1,631	1,957	2,361	2,949	3,603	4,382	5,431	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	19,546	19,682	20,923	21,164	21,285	20,786	20,144	20,596	21,054	21,817	0	0	0	0
TOTAL OIL (MMB)	1,532	1,526	1,712	1,751	1,818	1,688	1,524	1,457	1,362	1,190	0	0	0	0
TOTAL GAS (BCF)	21,557	21,713	23,175	23,476	23,691	23,026	22,172	22,492	22,798	23,357	0	0	0	0
TOTAL NGL (MMB)	868	868	920	918	907	853	785	776	760	727	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,717	1,732	1,758	1,792	1,828	1,855	1,862	1,853	1,831	1,791	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,106	2,112	2,137	2,178	2,220	2,257	2,260	2,230	2,230	2,172	0	0	0	0
HIGH PERMEABILITY (BCF)	12,840	13,132	13,302	13,471	13,695	13,648	13,732	13,636	13,514	13,254	0	0	0	0
LOW PERMEABILITY (BCF)	1,843	1,918	1,981	2,047	2,068	2,030	2,034	2,020	2,055	2,092	0	0	0	0
DEVONIAN SHALE (BCF)	530	553	551	542	538	516	521	518	527	526	0	0	0	0
COAL BED METHANE (BCF)	1,114	1,115	1,111	1,109	1,100	1,110	1,138	1,174	1,205	1,271	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	377	399	403	413	417	398	374	348	342	309	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	263	333	412	521	641	773	959	1,171	1,442	1,779	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,968	17,450	17,761	18,103	18,459	18,476	18,758	18,867	19,085	19,231	0	0	0	0
TOTAL OIL (MMB)	1,717	1,732	1,758	1,792	1,828	1,855	1,862	1,853	1,831	1,791	0	0	0	0
TOTAL GAS (BCF)	19,074	19,561	19,899	20,281	20,679	20,733	21,025	21,126	21,315	21,403	0	0	0	0
TOTAL NGL (MMB)	797	813	821	831	839	834	835	828	824	816	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	16,303	16,097	16,051	16,010	16,000	15,832	15,494	15,098	14,629	14,028	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	18,066	17,986	18,101	18,235	18,422	18,405	18,166	17,803	17,318	16,685	0	0	0	0
HIGH PERMEABILITY (BCF)	83,135	84,038	85,715	87,383	88,654	88,955	88,014	86,825	85,151	83,137	0	0	0	0
LOW PERMEABILITY (BCF)	19,663	19,997	20,525	20,837	20,987	21,235	21,473	21,745	22,054	22,414	0	0	0	0
DEVONIAN SHALE (BCF)	5,559	5,895	6,040	6,158	6,185	6,206	6,202	6,184	6,176	6,206	0	0	0	0
COAL BED METHANE (BCF)	10,649	10,488	10,316	10,109	10,111	10,260	10,509	10,888	11,525	12,371	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,931	3,051	3,120	3,180	3,239	3,241	3,094	2,949	2,712	2,424	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	2,808	3,507	4,421	5,532	6,847	8,435	10,425	12,858	15,798	19,450	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	124,744	126,976	130,137	133,198	136,023	138,333	139,718	141,447	143,415	146,002	0	0	0	0
TOTAL OIL (MMB)	16,303	16,097	16,051	16,010	16,000	15,832	15,494	15,098	14,629	14,028	0	0	0	0
TOTAL GAS (BCF)	142,810	144,961	148,238	151,433	154,445	156,738	157,885	159,250	160,733	162,687	0	0	0	0
TOTAL NGL (MMB)	5,981	6,036	6,135	6,223	6,290	6,309	6,259	6,207	6,142	6,053	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,146	1,174	1,194	1,216	1,239	1,241	1,257	1,261	1,271	1,274	0	0	0	0

NPCHOPPA: NPC UPSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/06/92

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AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQISITION	1.76	1.73	1.57	1.55	1.70	1.88	2.03	2.27	2.36	2.56	2.75	2.96		
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.58	2.74	2.89	3.13	3.21	3.41	3.62	3.82		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.34	5.49	5.63	5.87	5.94	6.14	6.34	6.53		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.46	4.61	4.75	5.00	5.07	5.27	5.48	5.67		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.91	3.10	3.30	3.59	3.70	3.92	4.20	4.44		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.76	2.98	3.18	3.46	3.53	3.73	3.96	4.17		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.50	1.68	1.84	2.07	2.16	2.34	2.51	2.75		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.77	1.96	2.14	2.36	2.45	2.59	2.75	2.95		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.08	2.28	2.45	2.65	2.70	2.80	2.96	3.17		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.62	2.76	2.92	3.08	3.33	3.41	3.62	3.83	4.04		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQISITION	2.89	2.89	2.81	2.72	2.73	2.59	2.75	2.80	2.91	2.98	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.72	3.69	3.56	3.42	3.39	3.21	3.36	3.39	3.49	3.54	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.38	6.31	6.15	5.98	5.91	5.68	5.77	5.77	5.84	5.87	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.54	5.49	5.34	5.17	5.12	4.89	5.00	5.01	5.10	5.13	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.30	4.24	4.09	3.94	3.90	3.74	3.89	3.93	4.06	4.12	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.05	4.01	3.87	3.73	3.70	3.53	3.68	3.70	3.80	3.84	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.69	2.71	2.65	2.58	2.60	2.47	2.65	2.71	2.87	2.95	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.92	2.99	2.91	2.82	2.81	2.66	2.83	2.89	3.03	3.11	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.14	3.24	3.25	3.15	3.14	2.98	3.20	3.25	3.40	3.48	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	3.94	3.91	3.78	3.63	3.60	3.41	3.57	3.59	3.70	3.76	0.00	0.00	0.00	0.00

CASE 4

NPC Downside Option Case Versus High Reference Case

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/04/92

Run Time: 03:48 PM

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,814	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,341	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,105	17,347	75.6	82.9	1.03	1.26
1992	18.46	1.32	1.49	1.47	41.5	13,667	17,554	77.9	85.5	1.03	1.30
1993	18.60	1.53	1.70	1.64	47.7	13,753	17,741	77.5	88.5	1.07	1.46
1994	18.76	1.75	1.92	1.83	54.2	13,732	17,642	77.8	91.4	1.11	1.61
1995	19.01	2.01	2.18	2.06	61.3	14,451	17,615	82.0	93.7	1.17	1.75
1996	19.25	2.23	2.40	2.26	67.2	14,196	17,430	81.4	94.3	1.24	1.84
1997	19.56	2.27	2.44	2.29	67.2	15,701	17,382	90.3	94.4	1.24	1.87
1998	19.91	2.49	2.66	2.51	72.5	15,280	17,562	87.0	95.2	1.25	2.04
1999	20.51	2.68	2.85	2.71	75.9	16,672	17,548	95.0	95.3	1.26	2.18
2000	21.10	2.84	3.01	2.87	78.1	17,619	17,652	99.8	95.5	1.28	2.26
2001	21.75	2.97	3.14	3.00	79.2	18,180	17,983	101.1	95.7	1.29	2.35
2002	22.55	2.93	3.10	2.96	75.4	19,310	18,165	106.3	95.4	1.32	2.27
2003	23.45	3.00	3.17	3.02	74.2	19,522	18,448	105.8	95.2	1.33	2.31
2004	24.25	3.04	3.20	3.04	72.6	19,651	18,653	105.4	95.0	1.34	2.32
2005	25.14	3.10	3.27	3.09	71.5	19,443	18,814	103.3	94.8	1.33	2.37
2006	25.74	3.22	3.39	3.20	72.6	18,418	18,865	97.6	94.9	1.33	2.47
2007	26.25	3.35	3.51	3.33	73.9	17,463	18,644	93.7	95.1	1.34	2.55
2008	26.75	3.50	3.67	3.49	76.0	17,246	18,506	93.2	95.3	1.34	2.67
2009	27.35	3.79	3.96	3.77	80.3	17,573	18,300	96.0	95.4	1.33	2.90
2010	27.85	3.92	4.09	3.91	81.7	18,038	18,208	99.1	95.4	1.32	3.04
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/04/92

Run Time: 03:48 PM

LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
DEMAND														
RESIDENTIAL	4,900	4,498	4,700	4,852	4,853	4,859	4,888	4,886	4,882	4,882	4,871	4,857		
COMMERCIAL *	2,772	2,730	2,846	2,849	2,846	2,856	2,873	2,874	2,868	2,873	2,891	2,924		
INDUSTRIAL	6,939	7,046	7,376	7,408	7,640	7,759	7,769	7,737	7,741	7,806	7,781	7,810		
BOILERS	2,792	2,831	2,983	2,921	3,008	3,073	3,085	3,092	3,081	3,108	3,100	3,079		
NONBOILERS	4,148	4,215	4,393	4,487	4,632	4,686	4,684	4,645	4,660	4,698	4,681	4,731		
ELECTRIC UTILITY	2,808	2,852	2,905	2,890	2,903	2,912	2,988	3,072	3,202	3,273	3,313	3,450		
TOTAL END USE DEMAND	17,419	17,126	17,827	17,999	18,241	18,385	18,519	18,569	18,693	18,834	18,857	19,040		
LEASE AND PLANT USE	886	1,060	1,093	1,107	1,116	1,107	1,104	1,090	1,085	1,095	1,092	1,097		
TRANSMISSION FUEL	655	644	670	677	686	691	696	698	703	708	709	716		
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547		
TOTAL DISPOSITION	19,138	19,002	19,848	20,102	20,431	20,615	20,782	20,841	20,981	21,153	21,189	21,400		
SUPPLY														
LOWER-48 PRODUCTION	17,652	17,342	17,938	18,061	18,249	18,144	18,115	17,922	17,875	18,064	18,042	18,147		
PIPELINE IMPORTS	1,327	1,465	1,709	1,837	1,984	2,225	2,397	2,533	2,645	2,554	2,566	2,638		
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0		
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	254	366	439	510	553	585		
TOTAL GAS SUPPLY	19,131	18,998	19,844	20,096	20,425	20,604	20,766	20,822	20,958	21,128	21,162	21,370		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,850	4,843	4,842	4,845	4,854	4,856	4,847	4,847	4,854	4,863	0	0	0	0
COMMERCIAL *	2,975	3,022	3,083	3,144	3,214	3,257	3,297	3,336	3,364	3,370	0	0	0	0
INDUSTRIAL	7,970	8,087	8,193	8,299	8,347	8,421	8,406	8,472	8,441	8,479	0	0	0	0
BOILERS	3,190	3,281	3,351	3,424	3,459	3,508	3,503	3,541	3,466	3,473	0	0	0	0
NONBOILERS	4,780	4,806	4,841	4,874	4,888	4,913	4,903	4,931	4,974	5,006	0	0	0	0
ELECTRIC UTILITY	3,587	3,677	3,776	3,857	3,934	4,043	4,158	4,243	4,297	4,326	0	0	0	0
TOTAL END USE DEMAND	19,382	19,629	19,894	20,144	20,348	20,576	20,708	20,898	20,955	21,038	0	0	0	0
LEASE AND PLANT USE	1,117	1,126	1,142	1,153	1,161	1,162	1,146	1,136	1,122	1,113	0	0	0	0
TRANSMISSION FUEL	729	738	748	757	765	774	779	786	788	791	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	21,742	21,976	22,238	22,475	22,662	22,853	22,925	23,101	23,147	23,139	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	18,508	18,676	18,975	19,191	19,359	19,412	19,218	19,070	18,856	18,779	0	0	0	0
PIPELINE IMPORTS	2,644	2,748	2,728	2,771	2,797	2,919	3,108	3,303	3,456	3,505	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	566	536	515	498	490	499	580	711	816	847	0	0	0	0
TOTAL GAS SUPPLY	21,717	21,960	22,218	22,460	22,646	22,830	22,906	23,085	23,130	23,131	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/04/92

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ENERGY DEMAND FOR COMBUSTION USES
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,419	17,126	17,827	17,999	18,241	18,385	18,519	18,569	18,693	18,834	18,857	19,040
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,960	1,869	1,902	2,000	2,081	2,120	2,137	2,241	2,260
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,613	2,624	2,623	2,618	2,622	2,628	2,628	2,615
LPG (RES/COM SECTORS)	470	429	420	426	428	427	427	424	422	419	415	411
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,082	18,153	18,268	18,449	18,785	19,038	19,338	19,624
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,225
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,277	49,986	50,541	51,043	51,464	51,873	52,304	52,820	53,328	53,768	54,332
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,578	9,684	9,795	9,960	10,137	10,303	10,474	10,652
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,912)	(30,194)	(30,465)	(30,768)	(31,149)	(31,578)	(31,925)	(32,284)	(32,655)
END USE ENERGY DEMAND	29,516	29,108	29,693	30,102	30,426	30,683	30,900	31,115	31,378	31,706	31,957	32,329

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	19,382	19,629	19,894	20,144	20,348	20,576	20,708	20,898	20,955	21,038	0	0	0	0
RESIDUAL FUEL OIL	2,081	1,885	1,821	1,822	1,828	1,837	1,875	1,912	2,117	2,167	0	0	0	0
DISTILLATE FUEL OIL	2,621	2,670	2,670	2,623	2,622	2,620	2,614	2,615	2,607	2,605	0	0	0	0
LPG (RES/COM SECTORS)	409	405	401	397	394	390	386	383	382	381	0	0	0	0
COAL (EXCLUDES COKING COAL)	20,088	20,552	20,989	21,398	21,807	22,238	22,682	23,117	23,625	24,174	0	0	0	0
HYDRO/RENEWABLES	3,252	3,282	3,314	3,346	3,379	3,413	3,449	3,484	3,523	3,573	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	54,937	55,477	56,094	56,684	57,282	57,926	58,515	59,160	59,911	60,589	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,837	11,018	11,213	11,398	11,590	11,800	12,016	12,216	12,429	12,641	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(33,091)	(33,515)	(33,990)	(34,450)	(34,924)	(35,458)	(36,012)	(36,536)	(37,102)	(37,664)	0	0	0	0
END USE ENERGY DEMAND	32,683	32,980	33,317	33,633	33,948	34,269	34,519	34,840	35,238	35,566	0	0	0	0

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)												Run Date: 09/04/92
Run Time: 03:48 PM												
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,401	3,457	3,516	3,571	3,631	3,691
DISTILLATE OIL	1,165	898	877	898	899	892	886	877	868	858	845	831
LPG	400	364	358	361	363	363	362	360	358	356	352	348
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,498	4,700	4,852	4,853	4,859	4,888	4,886	4,882	4,882	4,871	4,857
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,961	9,245	9,459	9,500	9,537	9,598	9,640	9,683	9,727	9,758	9,786
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,050	3,095	3,143	3,188	3,237	3,286
DISTILLATE OIL	561	518	509	521	526	528	526	525	524	523	522	526
LPG	70	65	63	65	65	65	64	64	64	63	63	64
COAL	88	94	88	94	94	95	94	94	93	93	93	93
NATURAL GAS	2,772	2,730	2,846	2,849	2,846	2,856	2,873	2,874	2,868	2,873	2,891	2,924
RESIDUAL OIL	228	226	223	220	214	210	207	202	198	195	192	191
TOTAL FUELS	6,472	6,494	6,653	6,703	6,731	6,770	6,814	6,853	6,890	6,934	6,998	7,082
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,408	7,640	7,759	7,769	7,737	7,741	7,806	7,781	7,810
HIGH SULFUR RESID	311	288	249	270	254	252	258	281	272	302	329	363
LOW SULFUR RESID	301	286	252	304	275	285	319	373	460	488	521	592
DISTILLATE	1,133	1,167	1,103	1,096	1,109	1,117	1,117	1,114	1,118	1,118	1,114	1,108
ELECTRICITY	3,135	3,212	3,195	3,231	3,268	3,305	3,344	3,408	3,478	3,543	3,607	3,675
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,681	1,709	1,737	1,788	1,849	1,913
TOTAL FUELS	13,471	13,653	13,794	13,941	14,195	14,376	14,488	14,621	14,805	15,044	15,201	15,461
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,890	2,903	2,912	2,988	3,072	3,202	3,273	3,313	3,450
HIGH SULFUR RESID	590	490	477	570	471	492	525	554	553	552	564	485
LOW SULFUR RESID	858	671	634	596	656	662	692	672	638	601	634	628
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	150
COAL	15,842	16,067	16,009	16,085	16,277	16,340	16,432	16,586	16,894	17,098	17,337	17,559
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,383
TOTAL FUELS	28,733	29,381	29,664	29,912	30,194	30,465	30,768	31,149	31,578	31,925	32,284	32,655
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,419	17,126	17,827	17,999	18,241	18,385	18,519	18,569	18,693	18,834	18,857	19,040
HIGH SULFUR RESID	901	778	726	840	724	744	783	834	824	854	893	848
LOW SULFUR RESID	1,386	1,183	1,109	1,119	1,145	1,158	1,217	1,247	1,295	1,283	1,348	1,411
DISTILLATE	2,988	2,640	2,556	2,588	2,613	2,624	2,623	2,618	2,622	2,628	2,628	2,615
COAL	17,640	17,878	17,775	17,870	18,082	18,153	18,268	18,449	18,785	19,038	19,338	19,624
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,238	10,400	10,463	10,586	10,601	10,691	10,703	10,794
TOTAL FUELS	49,308	49,277	49,986	50,541	51,042	51,464	51,872	52,304	52,820	53,327	53,767	54,332

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)											Run Date: 09/04/92 Run Time: 03:48 PM			
LOWER 48 ENERGY DEMAND (Trillion Btus)														
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,751	3,812	3,877	3,939	4,004	4,070	4,141	4,208	4,278	4,348	0	0	0	0
DISTILLATE OIL	818	805	791	777	764	752	739	729	721	713	0	0	0	0
LPG	344	340	336	331	327	323	319	316	314	312	0	0	0	0
COAL	59	58	58	58	58	57	57	57	56	56	0	0	0	0
NATURAL GAS	4,850	4,843	4,842	4,845	4,854	4,856	4,847	4,847	4,854	4,863	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,822	9,858	9,903	9,949	10,006	10,058	10,102	10,155	10,223	10,293	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,333	3,382	3,435	3,484	3,537	3,590	3,648	3,701	3,757	3,811	0	0	0	0
DISTILLATE OIL	532	537	541	544	550	551	555	559	564	565	0	0	0	0
LPG	64	65	65	66	67	67	67	68	69	69	0	0	0	0
COAL	94	95	96	96	98	98	98	99	100	100	0	0	0	0
NATURAL GAS	2,975	3,022	3,083	3,144	3,214	3,257	3,297	3,336	3,364	3,370	0	0	0	0
RESIDUAL OIL	191	191	191	192	193	192	192	192	191	190	0	0	0	0
TOTAL FUELS	7,190	7,291	7,411	7,527	7,657	7,755	7,857	7,954	8,044	8,104	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	7,970	8,087	8,193	8,299	8,347	8,421	8,406	8,472	8,441	8,479	0	0	0	0
HIGH SULFUR RESID	335	285	253	220	210	204	212	216	328	361	0	0	0	0
LOW SULFUR RESID	552	520	493	467	454	444	448	452	515	534	0	0	0	0
DISTILLATE	1,117	1,125	1,132	1,140	1,143	1,148	1,147	1,150	1,141	1,142	0	0	0	0
ELECTRICITY	3,753	3,824	3,902	3,975	4,050	4,140	4,228	4,307	4,395	4,482	0	0	0	0
COAL	1,946	1,990	2,031	2,057	2,081	2,099	2,119	2,133	2,152	2,172	0	0	0	0
TOTAL FUELS	15,672	15,832	16,003	16,157	16,285	16,456	16,560	16,732	16,971	17,168	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	3,587	3,677	3,776	3,857	3,934	4,043	4,158	4,243	4,297	4,326	0	0	0	0
HIGH SULFUR RESID	442	350	331	340	337	338	340	343	394	406	0	0	0	0
LOW SULFUR RESID	562	539	553	604	635	658	683	708	689	678	0	0	0	0
DISTILLATE	153	204	207	163	166	170	174	177	181	185	0	0	0	0
COAL	17,990	18,408	18,805	19,187	19,571	19,984	20,408	20,829	21,317	21,846	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,358	10,338	10,319	10,300	10,282	10,265	10,251	10,236	10,225	10,224	0	0	0	0
TOTAL FUELS	33,091	33,515	33,990	34,450	34,924	35,458	36,012	36,536	37,102	37,664	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	19,382	19,629	19,894	20,144	20,348	20,576	20,708	20,898	20,955	21,038	0	0	0	0
HIGH SULFUR RESID	777	635	584	560	547	543	552	559	722	766	0	0	0	0
LOW SULFUR RESID	1,304	1,250	1,237	1,263	1,281	1,294	1,323	1,352	1,395	1,401	0	0	0	0
DISTILLATE	2,621	2,670	2,670	2,623	2,622	2,620	2,614	2,615	2,607	2,605	0	0	0	0
COAL	20,088	20,552	20,989	21,398	21,807	22,238	22,682	23,117	23,625	24,174	0	0	0	0
ALL OTHER FUELS	10,766	10,742	10,719	10,697	10,676	10,655	10,637	10,620	10,607	10,605	0	0	0	0
TOTAL FUELS	54,937	55,477	56,094	56,684	57,281	57,926	58,515	59,160	59,910	60,589	0	0	0	0

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (TABLE 2: LOWER 48 WELLS AND RESERVES)												Run Date: 09/04/92
												Run Time: 03:48 PM
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,567	4,448	4,325	4,924	5,533	5,377	5,710	6,405	7,335	8,477
DEVELOPMENT WELLS	22,582	27,158	26,414	20,364	20,818	23,805	26,948	25,021	23,955	24,733	27,277	28,157
TOTAL GAS WELLS	9,472	10,333	9,899	7,532	7,434	8,013	9,325	9,176	10,176	9,675	10,631	11,259
TOTAL WELLS	28,326	33,314	31,981	24,812	25,143	28,729	32,481	30,398	29,665	31,137	34,611	36,634
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	936	1,657	1,519	1,354	1,208	1,116	1,038	1,083	1,156	1,166
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,012	1,844	1,728	1,599	1,456	1,385	1,337	1,397	1,482	1,485
HIGH PERMEABILITY (BCF)	9,905	12,223	7,432	7,986	8,918	8,833	9,533	9,395	10,823	10,264	10,922	11,494
LOW PERMEABILITY (BCF)	1,339	1,691	1,532	1,798	1,059	1,248	1,035	966	1,108	1,128	1,498	1,752
DEVONIAN SHALE (BCF)	384	504	397	315	319	342	387	415	522	599	689	675
COAL BED METHANE (BCF)	1,607	2,111	2,386	1,411	1,449	1,445	1,595	1,529	1,131	958	1,024	1,003
ENHANCED RECOVERY GAS (BCF)	443	303	296	179	147	136	302	342	405	515	568	613
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	133	132	129	144	165	376	420	491	597
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,093	11,823	12,026	12,133	12,995	12,811	14,364	13,883	15,191	16,134
TOTAL OIL (MMB)	1,194	1,388	936	1,657	1,519	1,354	1,208	1,116	1,038	1,083	1,156	1,166
TOTAL GAS (BCF)	15,127	18,454	13,105	13,667	13,753	13,732	14,451	14,196	15,701	15,280	16,672	17,619
TOTAL NGL (MMB)	550	681	432	526	516	526	547	553	622	612	669	706
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,722	1,710	1,678	1,648	1,636	1,615	1,593	1,579	1,566
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,481	2,374	2,235	2,151	2,102	2,072	2,026	1,975	1,935
HIGH PERMEABILITY (BCF)	12,035	12,429	12,368	12,360	12,520	12,455	12,402	12,218	12,117	12,191	12,070	12,018
LOW PERMEABILITY (BCF)	1,665	1,673	1,700	1,853	1,835	1,782	1,754	1,680	1,603	1,609	1,626	1,690
DEVONIAN SHALE (BCF)	152	180	210	225	237	254	269	275	296	322	352	379
COAL BED METHANE (BCF)	103	178	285	422	547	679	786	890	994	1,049	1,089	1,101
ENHANCED RECOVERY GAS (BCF)	83	114	138	162	165	166	175	182	196	229	271	330
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	51	63	71	78	83	103	137	165	199
TOTAL NON-ASSOC GAS (BCF)	14,085	14,621	14,749	15,073	15,368	15,407	15,464	15,328	15,310	15,536	15,572	15,718
TOTAL OIL (MMB)	1,871	1,782	1,751	1,722	1,710	1,678	1,648	1,636	1,615	1,593	1,579	1,566
TOTAL GAS (BCF)	16,814	17,341	17,347	17,554	17,741	17,642	17,615	17,430	17,382	17,562	17,548	17,652
TOTAL NGL (MMB)	739	751	747	758	763	750	744	738	738	748	747	747
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,854	18,789	18,598	18,274	17,835	17,315	16,739	16,228	15,805	15,405
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,303	21,666	21,020	20,384	19,688	18,971	18,236	17,608	17,114	16,664
HIGH PERMEABILITY (BCF)	105,428	105,222	100,388	96,015	92,413	88,791	85,922	83,098	81,804	79,876	78,728	78,204
LOW PERMEABILITY (BCF)	22,837	22,855	22,709	22,654	21,879	21,345	20,626	19,913	19,417	18,936	18,808	18,870
DEVONIAN SHALE (BCF)	1,751	2,076	2,263	2,353	2,435	2,523	2,641	2,781	3,006	3,284	3,621	3,917
COAL BED METHANE (BCF)	2,798	4,731	6,833	7,822	8,724	9,489	10,299	10,937	11,074	10,983	10,918	10,820
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,328	1,310	1,280	1,407	1,566	1,775	2,062	2,359	2,641
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	618	687	745	810	893	1,165	1,447	1,774	2,172
TOTAL NON-ASSOC GAS (BCF)	134,283	136,571	134,039	130,790	127,448	124,174	121,705	119,187	118,242	116,588	116,207	116,623
TOTAL OIL (MMB)	20,063	19,670	18,854	18,789	18,598	18,274	17,835	17,315	16,739	16,228	15,805	15,405
TOTAL GAS (BCF)	159,324	160,437	156,342	152,456	148,467	144,558	141,393	138,159	136,478	134,196	133,321	133,287
TOTAL NGL (MMB)	7,500	7,430	7,115	6,883	6,637	6,412	6,215	6,029	5,913	5,777	5,698	5,657
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,059	1,072	1,081	1,073	1,069	1,056	1,051	1,060	1,057	1,062

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (# TABLE 2: LOWER 48 WELLS AND RESERVES)											Run Date: 09/04/92 Run Time: 03:48 PM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	10,015	11,884	12,309	12,499	12,935	13,210	13,301	13,258	12,197	11,703	0	0	0	0
DEVELOPMENT WELLS	29,757	30,650	30,386	28,538	30,107	29,621	26,238	24,943	25,300	26,897	0	0	0	0
TOTAL GAS WELLS	11,655	12,586	12,720	12,566	12,381	12,583	12,063	12,031	12,519	12,515	0	0	0	0
TOTAL WELLS	39,772	42,534	42,696	41,037	43,043	42,832	39,539	38,201	37,497	38,600	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,230	1,247	1,259	1,282	1,326	1,234	1,028	951	861	821	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,566	1,625	1,650	1,689	1,722	1,600	1,346	1,215	1,089	1,046	0	0	0	0
HIGH PERMEABILITY (BCF)	11,894	12,497	12,640	12,555	12,253	11,200	10,402	9,939	9,758	9,526	0	0	0	0
LOW PERMEABILITY (BCF)	1,833	2,050	1,883	1,837	1,655	1,556	1,487	1,569	1,636	1,571	0	0	0	0
DEVONIAN SHALE (BCF)	645	742	825	817	730	618	395	276	211	174	0	0	0	0
COAL BED METHANE (BCF)	988	1,069	990	946	1,014	1,096	1,221	1,232	1,315	1,547	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	519	421	450	478	482	452	302	215	196	95	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	735	906	1,084	1,329	1,588	1,896	2,309	2,801	3,366	4,080	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,613	17,685	17,872	17,963	17,721	16,818	16,117	16,031	16,483	16,992	0	0	0	0
TOTAL OIL (MMB)	1,230	1,247	1,259	1,282	1,326	1,234	1,028	951	861	821	0	0	0	0
TOTAL GAS (BCF)	18,180	19,310	19,522	19,651	19,443	18,418	17,463	17,246	17,573	18,038	0	0	0	0
TOTAL NGL (MMB)	729	772	783	774	752	694	634	610	603	580	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,555	1,549	1,548	1,548	1,551	1,550	1,533	1,500	1,460	1,413	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,907	1,881	1,874	1,871	1,876	1,870	1,841	1,808	1,746	1,677	0	0	0	0
HIGH PERMEABILITY (BCF)	12,161	12,241	12,374	12,457	12,482	12,413	12,166	11,965	11,684	11,475	0	0	0	0
LOW PERMEABILITY (BCF)	1,781	1,822	1,873	1,876	1,867	1,843	1,789	1,745	1,720	1,692	0	0	0	0
DEVONIAN SHALE (BCF)	401	421	448	487	506	511	485	453	427	408	0	0	0	0
COAL BED METHANE (BCF)	1,109	1,116	1,122	1,113	1,119	1,123	1,140	1,161	1,182	1,215	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	376	380	377	394	409	427	423	386	338	302	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	248	304	381	455	554	677	800	988	1,202	1,438	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,076	16,284	16,574	16,783	16,938	16,995	16,803	16,698	16,554	16,531	0	0	0	0
TOTAL OIL (MMB)	1,555	1,549	1,548	1,548	1,551	1,550	1,533	1,500	1,460	1,413	0	0	0	0
TOTAL GAS (BCF)	17,983	18,165	18,448	18,653	18,814	18,865	18,644	18,506	18,300	18,208	0	0	0	0
TOTAL NGL (MMB)	758	760	768	769	769	766	754	741	726	711	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	15,081	14,779	14,489	14,223	13,998	13,682	13,177	12,629	12,031	11,439	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	16,324	16,067	15,843	15,661	15,506	15,236	14,741	14,149	13,491	12,861	0	0	0	0
HIGH PERMEABILITY (BCF)	77,937	78,193	78,459	78,557	78,328	77,115	75,351	73,325	71,398	69,448	0	0	0	0
LOW PERMEABILITY (BCF)	18,922	19,149	19,159	19,121	18,910	18,623	18,321	18,144	18,060	17,939	0	0	0	0
DEVONIAN SHALE (BCF)	4,161	4,482	4,858	5,188	5,411	5,518	5,429	5,252	5,037	4,802	0	0	0	0
COAL BED METHANE (BCF)	10,699	10,653	10,521	10,353	10,248	10,221	10,302	10,373	10,506	10,838	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,783	2,824	2,898	2,982	3,055	3,080	2,959	2,787	2,645	2,438	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	2,658	3,260	3,963	4,837	5,870	7,089	8,598	10,410	12,575	15,216	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	117,160	118,561	119,859	121,039	121,823	121,645	120,959	120,291	120,220	120,681	0	0	0	0
TOTAL OIL (MMB)	15,081	14,779	14,489	14,223	13,998	13,682	13,177	12,629	12,031	11,439	0	0	0	0
TOTAL GAS (BCF)	133,484	134,628	135,702	136,700	137,329	136,881	135,700	134,439	133,712	133,542	0	0	0	0
TOTAL NGL (MMB)	5,629	5,641	5,655	5,660	5,643	5,570	5,450	5,319	5,196	5,066	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,081	1,090	1,106	1,116	1,124	1,125	1,110	1,100	1,086	1,078	0	0	0	0

NPCHOPMA: NPC DOWNSIDE OPTION CASE VS HIGH REFERENCE CASE (#4)

Run Date: 09/04/92

Run Time: 03:48 PM

AVERAGE NATURAL GAS PRICES

(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
LDC GAS TARIFF PRICES												
AVERAGE AQUISITION	1.76	1.73	1.57	1.55	1.71	1.91	2.12	2.37	2.39	2.60	2.80	2.97
AVERAGE CITYGATE	2.75	2.73	2.53	2.46	2.59	2.77	3.01	3.29	3.32	3.56	3.81	3.99
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.36	5.53	5.77	6.07	6.09	6.35	6.60	6.79
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.48	4.65	4.89	5.18	5.20	5.46	5.72	5.91
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.92	3.14	3.43	3.76	3.82	4.09	4.45	4.64
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.65	2.77	3.02	3.32	3.62	3.64	3.89	4.17	4.36

END USER CARRIAGE PRICES

AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.51	1.71	1.94	2.15	2.18	2.39	2.58	2.75
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.78	2.00	2.24	2.44	2.47	2.61	2.79	2.95
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.09	2.32	2.56	2.68	2.72	2.82	3.00	3.17
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.63	2.77	2.96	3.21	3.50	3.52	3.77	4.04	4.23

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	3.10	3.09	3.15	3.15	3.20	3.29	3.43	3.62	3.91	4.03	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	4.12	4.11	4.16	4.15	4.18	4.28	4.43	4.62	4.94	5.06	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.91	6.87	6.91	6.88	6.90	7.00	7.15	7.35	7.67	7.80	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	6.04	6.01	6.05	6.03	6.05	6.15	6.31	6.51	6.83	6.96	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.78	4.73	4.79	4.78	4.82	4.93	5.09	5.30	5.64	5.80	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.49	4.46	4.50	4.48	4.50	4.59	4.75	4.94	5.27	5.39	0.00	0.00	0.00	0.00

END USER CARRIAGE PRICES

AVG SPOT ACQUISITION	2.85	2.86	2.93	2.96	3.02	3.13	3.26	3.42	3.71	3.84	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	3.08	3.07	3.19	3.28	3.36	3.47	3.60	3.73	3.90	4.03	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.29	3.29	3.42	3.54	3.66	3.77	3.87	3.98	4.16	4.28	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	4.36	4.34	4.40	4.39	4.42	4.52	4.68	4.88	5.21	5.34	0.00	0.00	0.00	0.00

CASE 5

NPC Upside Option Case
Versus
Low Reference Case

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

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ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,821	89.9	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,355	106.3	82.7	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,211	17,366	76.1	82.9	1.02	1.27
1992	17.66	1.32	1.49	1.47	43.4	13,803	17,542	78.7	85.4	0.99	1.36
1993	16.90	1.35	1.52	1.46	46.3	12,639	17,509	72.2	87.6	0.98	1.40
1994	16.17	1.46	1.63	1.55	52.4	12,248	17,316	70.7	90.7	0.97	1.54
1995	15.50	1.51	1.68	1.58	56.4	12,064	17,308	69.7	94.0	0.96	1.60
1996	15.77	1.77	1.94	1.82	65.2	12,495	16,736	74.7	94.4	0.97	1.86
1997	16.06	1.91	2.07	1.94	68.8	13,036	16,624	78.4	95.1	0.96	2.03
1998	16.36	2.09	2.25	2.12	74.0	13,520	16,488	82.0	95.5	0.95	2.25
1999	16.67	2.21	2.38	2.26	76.9	15,629	16,453	95.0	95.8	0.95	2.38
2000	17.00	2.31	2.48	2.37	78.7	17,747	16,756	105.9	95.8	0.94	2.52
2001	17.30	2.31	2.48	2.38	77.5	18,411	17,173	107.2	95.9	0.94	2.52
2002	17.59	2.33	2.50	2.40	76.9	18,918	17,582	107.6	95.9	0.94	2.54
2003	17.90	2.33	2.50	2.40	75.6	19,691	18,004	109.4	95.8	0.93	2.57
2004	18.19	2.25	2.42	2.32	71.9	20,671	18,309	112.9	95.5	0.91	2.51
2005	18.50	2.26	2.43	2.33	71.0	20,375	18,694	109.0	95.4	0.90	2.55
2006	18.79	2.29	2.46	2.35	70.6	19,788	18,792	105.3	95.2	0.90	2.58
2007	19.10	2.34	2.51	2.39	71.0	19,412	18,790	103.3	95.2	0.89	2.67
2008	19.40	2.32	2.49	2.36	69.3	19,221	18,827	102.1	94.7	0.87	2.72
2009	19.69	2.46	2.62	2.49	72.3	19,283	18,939	101.8	94.9	0.86	2.92
2010	20.00	2.50	2.67	2.52	72.6	19,486	18,926	103.0	94.8	0.84	3.04
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DEMAND												
RESIDENTIAL	4,900	4,497	4,700	4,877	4,893	4,914	4,944	4,935	4,913	4,877	4,853	4,826
COMMERCIAL *	2,771	2,729	2,847	2,861	2,851	2,868	2,892	2,914	2,928	2,952	3,022	3,117
INDUSTRIAL	6,949	7,060	7,394	7,370	7,432	7,374	7,305	7,064	6,997	6,953	6,865	6,771
BOILERS	2,791	2,831	2,985	2,900	2,918	2,893	2,865	2,718	2,661	2,627	2,572	2,512
NONBOILERS	4,158	4,229	4,409	4,470	4,514	4,480	4,440	4,346	4,337	4,325	4,294	4,259
ELECTRIC UTILITY	2,808	2,852	2,905	2,884	2,870	2,885	2,994	2,928	3,039	2,975	2,994	3,317
TOTAL END USE DEMAND	17,428	17,139	17,846	17,991	18,046	18,041	18,135	17,841	17,878	17,756	17,734	18,031
LEASE AND PLANT USE	886	1,061	1,094	1,106	1,101	1,086	1,082	1,045	1,036	1,027	1,024	1,043
TRANSMISSION FUEL	655	644	671	677	679	678	682	671	672	668	667	678
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547
TOTAL DISPOSITION	19,148	19,017	19,869	20,093	20,213	20,235	20,362	20,041	20,085	19,966	19,956	20,299
SUPPLY												
LOWER-48 PRODUCTION	17,661	17,356	17,959	18,049	18,018	17,816	17,869	17,257	17,158	17,018	16,990	17,306
PIPELINE IMPORTS	1,327	1,466	1,709	1,840	1,991	2,208	2,382	2,567	2,678	2,615	2,585	2,557
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	153	191	197	199	199	199	212	310	343	426	475	531
TOTAL GAS SUPPLY	19,141	19,013	19,864	20,088	20,207	20,223	20,463	20,135	20,179	20,059	20,049	20,394

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,809	4,801	4,795	4,795	4,803	4,795	4,786	4,771	4,771	4,767	0	0	0	0
COMMERCIAL *	3,245	3,370	3,504	3,639	3,787	3,896	4,004	4,098	4,187	4,252	0	0	0	0
INDUSTRIAL	6,819	6,831	6,853	6,895	6,919	6,835	6,624	6,643	6,606	6,432	0	0	0	0
BOILERS	2,557	2,568	2,593	2,632	2,659	2,622	2,505	2,528	2,509	2,411	0	0	0	0
NONBOILERS	4,262	4,263	4,259	4,263	4,259	4,213	4,119	4,116	4,097	4,021	0	0	0	0
ELECTRIC UTILITY	3,510	3,706	3,921	4,035	4,172	4,354	4,668	4,699	4,897	5,162	0	0	0	0
TOTAL END USE DEMAND	18,383	18,707	19,073	19,363	19,681	19,880	20,082	20,211	20,462	20,611	0	0	0	0
LEASE AND PLANT USE	1,068	1,092	1,117	1,134	1,156	1,161	1,159	1,161	1,168	1,167	0	0	0	0
TRANSMISSION FUEL	691	703	717	728	740	748	755	760	769	775	0	0	0	0
UAF + EXPORTS	563	579	600	622	643	664	680	696	712	728	0	0	0	0
TOTAL DISPOSITION	20,705	21,082	21,507	21,847	22,220	22,452	22,676	22,828	23,111	23,281	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	17,706	18,139	18,576	18,896	19,309	19,428	19,411	19,449	19,551	19,500	0	0	0	0
PIPELINE IMPORTS	2,525	2,521	2,566	2,653	2,668	2,732	2,867	2,991	3,121	3,298	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	545	497	435	367	314	357	453	438	481	521	0	0	0	0
TOTAL GAS SUPPLY	20,776	21,157	21,577	21,916	22,292	22,516	22,732	22,878	23,154	23,319	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

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ENERGY DEMAND FOR COMBUSTION USES

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,428	17,139	17,846	17,991	18,046	18,041	18,135	17,841	17,878	17,756	17,734	18,031
RESIDUAL FUEL OIL	2,288	1,962	1,833	1,941	1,849	1,874	1,883	2,201	2,157	2,292	2,381	2,240
DISTILLATE FUEL OIL	2,989	2,641	2,557	2,589	2,601	2,603	2,472	2,453	2,449	2,445	2,432	2,408
LPG (RES/COM SECTORS)	470	429	420	428	431	432	431	429	427	423	417	412
COAL (EXCLUDES COKING COAL)	17,628	17,864	17,757	17,786	17,935	17,893	17,888	17,951	18,137	18,233	18,347	18,378
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,121	3,145	3,146	3,159	3,163	3,167	3,169	3,171
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,278	49,986	50,434	50,660	50,802	50,832	50,997	51,182	51,375	51,549	51,798
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,439	9,509	9,578	9,647	9,754	9,882	10,004	10,125	10,249
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,840)	(30,048)	(30,245)	(30,473)	(30,691)	(30,948)	(31,153)	(31,377)	(31,608)
END USE ENERGY DEMAND	29,515	29,109	29,693	30,034	30,122	30,135	30,006	30,061	30,116	30,227	30,297	30,438

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	18,383	18,707	19,073	19,363	19,681	19,880	20,082	20,211	20,462	20,611	0	0	0	0
RESIDUAL FUEL OIL	2,038	1,920	1,786	1,661	1,520	1,528	1,675	1,548	1,518	1,595	0	0	0	0
DISTILLATE FUEL OIL	2,400	2,392	2,382	2,374	2,415	2,342	2,316	2,306	2,295	2,262	0	0	0	0
LPG (RES/COM SECTORS)	407	403	398	393	389	382	378	374	370	365	0	0	0	0
COAL (EXCLUDES COKING COAL)	18,608	18,808	19,049	19,242	19,426	19,662	20,029	20,077	20,273	20,660	0	0	0	0
HYDRO/RENEWABLES	3,176	3,192	3,215	3,237	3,260	3,288	3,315	3,342	3,369	3,399	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	52,118	52,478	52,907	53,224	53,592	53,934	54,597	54,608	54,988	55,543	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,378	10,509	10,676	10,802	10,937	11,110	11,370	11,418	11,583	11,839	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(31,882)	(32,169)	(32,549)	(32,805)	(33,096)	(33,522)	(34,205)	(34,256)	(34,648)	(35,311)	0	0	0	0
END USE ENERGY DEMAND	30,614	30,817	31,034	31,221	31,434	31,523	31,762	31,770	31,923	32,071	0	0	0	0

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3) TABLE 2: LOWER 48 WELLS AND RESERVES											Run Date: 09/18/92	
											Run Time: 03:13 PM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,578	4,845	4,166	3,814	3,906	4,145	4,593	5,432	6,836	8,347
DEVELOPMENT WELLS	22,582	27,158	26,428	22,580	19,509	17,864	18,604	18,658	18,441	21,545	26,049	30,073
TOTAL GAS WELLS	9,472	10,333	9,905	7,679	7,324	6,957	6,898	7,422	7,771	7,502	8,785	10,686
TOTAL WELLS	28,326	33,314	32,005	27,425	23,675	21,678	22,511	22,802	23,034	26,978	32,885	38,419
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	937	1,709	1,421	1,169	1,053	1,037	1,002	1,114	1,193	1,298
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,014	1,916	1,592	1,318	1,213	1,259	1,278	1,445	1,531	1,641
HIGH PERMEABILITY (BCF)	9,905	12,223	7,503	7,958	7,882	8,019	7,991	8,419	9,379	9,454	10,848	12,421
LOW PERMEABILITY (BCF)	1,339	1,691	1,535	1,803	1,052	850	728	762	796	1,023	1,410	1,602
DEVONIAN SHALE (BCF)	384	504	401	329	345	370	406	435	505	665	751	722
COAL BED METHANE (BCF)	1,607	2,111	2,413	1,462	1,474	1,448	1,478	1,364	787	574	618	607
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	153	143	145	154	177	213	263	464
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	152	142	100	104	102	114	147	209	289
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,197	11,886	11,047	10,929	10,851	11,236	11,757	12,076	14,098	16,106
TOTAL OIL (MMB)	1,194	1,388	937	1,709	1,421	1,169	1,053	1,037	1,002	1,114	1,193	1,298
TOTAL GAS (BCF)	15,127	18,454	13,211	13,803	12,639	12,248	12,064	12,495	13,036	13,520	15,629	17,747
TOTAL NGL (MMB)	550	681	435	528	480	451	434	473	520	538	632	736
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,725	1,710	1,658	1,607	1,584	1,563	1,548	1,544	1,543
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,485	2,374	2,213	2,101	2,032	1,996	1,956	1,920	1,896
HIGH PERMEABILITY (BCF)	12,041	12,440	12,386	12,345	12,329	12,223	12,259	11,741	11,650	11,490	11,381	11,549
LOW PERMEABILITY (BCF)	1,666	1,675	1,700	1,848	1,787	1,706	1,642	1,566	1,480	1,480	1,524	1,603
DEVONIAN SHALE (BCF)	152	180	211	226	239	256	282	286	310	333	365	398
COAL BED METHANE (BCF)	103	178	286	424	552	685	790	887	978	1,011	1,025	1,009
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	162	161	160	149	133	136	150	195
ENHANCED RECOVERY TIGHT (BCF)	47	48	48	52	65	71	75	74	78	82	89	106
TOTAL NON-ASSOC GAS (BCF)	14,091	14,634	14,768	15,057	15,135	15,102	15,207	14,703	14,628	14,532	14,534	14,860
TOTAL OIL (MMB)	1,871	1,782	1,751	1,725	1,710	1,658	1,607	1,584	1,563	1,548	1,544	1,543
TOTAL GAS (BCF)	16,821	17,355	17,366	17,542	17,509	17,316	17,308	16,736	16,624	16,488	16,453	16,756
TOTAL NGL (MMB)	740	752	748	757	752	737	732	704	703	700	700	710
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,855	18,839	18,551	18,061	17,508	16,961	16,399	15,966	15,616	15,370
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,736	20,954	20,059	19,171	18,398	17,680	17,169	16,780	16,525
HIGH PERMEABILITY (BCF)	105,413	105,196	100,415	96,028	91,581	87,376	83,109	79,787	77,516	75,479	74,947	75,819
LOW PERMEABILITY (BCF)	22,835	22,851	22,708	22,663	21,928	21,072	20,158	19,354	18,669	18,212	18,098	18,097
DEVONIAN SHALE (BCF)	1,751	2,076	2,265	2,369	2,475	2,589	2,713	2,862	3,057	3,390	3,775	4,100
COAL BED METHANE (BCF)	2,798	4,731	6,858	7,896	8,817	9,579	10,267	10,744	10,553	10,116	9,709	9,307
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,321	1,303	1,289	1,293	1,338	1,415	1,527	1,796
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	636	713	743	772	800	836	901	1,021	1,204
TOTAL NON-ASSOC GAS (BCF)	134,266	136,540	134,093	130,923	126,835	122,663	118,307	114,840	111,969	109,513	109,077	110,323
TOTAL OIL (MMB)	20,063	19,670	18,855	18,839	18,551	18,061	17,508	16,961	16,399	15,966	15,616	15,370
TOTAL GAS (BCF)	159,307	160,406	156,398	152,659	147,789	142,722	137,478	133,237	129,649	126,682	125,857	126,848
TOTAL NGL (MMB)	7,499	7,429	7,116	6,887	6,615	6,329	6,030	5,800	5,617	5,455	5,387	5,413
LEASE AND PLANT GAS (BCF)												
	857	1,027	1,060	1,071	1,066	1,051	1,048	1,012	1,003	995	992	1,010

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3) TABLE 2: LOWER 48 WELLS AND RESERVES											Run Date: 09/18/92 Run Time: 03:13 PM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	9,817	11,347	13,249	14,135	14,655	14,685	15,561	16,558	16,237	14,767	0	0	0	0
DEVELOPMENT WELLS	31,826	31,623	35,796	36,723	38,387	34,361	30,885	33,171	32,480	31,946	0	0	0	0
TOTAL GAS WELLS	11,674	12,286	12,516	13,290	13,146	12,980	13,168	12,685	12,939	12,699	0	0	0	0
TOTAL WELLS	41,643	42,970	49,045	50,859	53,042	49,046	46,446	49,729	48,717	46,713	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,323	1,342	1,436	1,481	1,593	1,416	1,190	1,198	1,126	1,070	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,684	1,731	1,889	1,962	2,073	1,837	1,574	1,565	1,485	1,427	0	0	0	0
HIGH PERMEABILITY (BCF)	12,837	13,018	13,362	13,802	13,168	12,690	12,685	12,230	11,935	11,792	0	0	0	0
LOW PERMEABILITY (BCF)	1,718	1,797	1,753	1,762	1,779	1,740	1,898	2,122	2,062	2,075	0	0	0	0
DEVONIAN SHALE (BCF)	725	854	1,010	1,003	905	782	490	304	263	196	0	0	0	0
COAL BED METHANE (BCF)	532	496	515	643	756	869	905	1,017	1,230	1,279	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	565	603	660	684	740	720	436	185	86	3	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	349	419	502	814	955	1,150	1,424	1,797	2,222	2,713	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,727	17,187	17,802	18,709	18,302	17,951	17,838	17,656	17,798	18,059	0	0	0	0
TOTAL OIL (MMB)	1,323	1,342	1,436	1,481	1,593	1,416	1,190	1,198	1,126	1,070	0	0	0	0
TOTAL GAS (BCF)	18,411	18,918	19,691	20,671	20,375	19,788	19,412	19,221	19,283	19,486	0	0	0	0
TOTAL NGL (MMB)	775	793	816	840	810	767	734	704	682	681	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,548	1,555	1,571	1,593	1,622	1,642	1,636	1,619	1,599	1,571	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,887	1,876	1,890	1,914	1,948	1,968	1,960	1,941	1,900	1,854	0	0	0	0
HIGH PERMEABILITY (BCF)	11,835	12,133	12,403	12,527	12,740	12,717	12,644	12,624	12,620	12,488	0	0	0	0
LOW PERMEABILITY (BCF)	1,666	1,713	1,763	1,797	1,807	1,794	1,781	1,794	1,843	1,882	0	0	0	0
DEVONIAN SHALE (BCF)	423	453	494	533	566	580	566	534	503	472	0	0	0	0
COAL BED METHANE (BCF)	986	954	924	905	888	868	874	878	913	947	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	245	296	342	395	436	480	491	469	424	380	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	131	157	189	238	309	385	473	588	737	903	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	15,286	15,705	16,114	16,395	16,746	16,824	16,830	16,886	17,040	17,072	0	0	0	0
TOTAL OIL (MMB)	1,548	1,555	1,571	1,593	1,622	1,642	1,636	1,619	1,599	1,571	0	0	0	0
TOTAL GAS (BCF)	17,173	17,582	18,004	18,309	18,694	18,792	18,790	18,827	18,939	18,926	0	0	0	0
TOTAL NGL (MMB)	725	742	758	768	779	779	773	765	760	752	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	15,145	14,932	14,797	14,685	14,656	14,431	13,985	13,563	13,089	12,589	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	16,322	16,176	16,175	16,224	16,348	16,217	15,831	15,455	15,041	14,614	0	0	0	0
HIGH PERMEABILITY (BCF)	76,821	77,706	78,665	79,941	80,368	80,342	80,382	79,989	79,303	78,607	0	0	0	0
LOW PERMEABILITY (BCF)	18,150	18,234	18,224	18,189	18,161	18,107	18,224	18,551	18,770	18,963	0	0	0	0
DEVONIAN SHALE (BCF)	4,401	4,803	5,318	5,789	6,128	6,330	6,255	6,025	5,786	5,511	0	0	0	0
COAL BED METHANE (BCF)	8,853	8,395	7,986	7,724	7,592	7,593	7,624	7,764	8,081	8,413	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,116	2,423	2,741	3,029	3,333	3,572	3,517	3,233	2,895	2,518	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	1,423	1,685	1,998	2,574	3,220	3,984	4,935	6,144	7,629	9,439	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	111,763	113,245	114,932	117,245	118,801	119,929	120,937	121,706	122,464	123,452	0	0	0	0
TOTAL OIL (MMB)	15,145	14,932	14,797	14,685	14,656	14,431	13,985	13,563	13,089	12,589	0	0	0	0
TOTAL GAS (BCF)	128,085	129,421	131,107	133,469	135,150	136,146	136,768	137,161	137,505	138,065	0	0	0	0
TOTAL NGL (MMB)	5,463	5,513	5,571	5,643	5,673	5,662	5,623	5,561	5,484	5,412	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,034	1,058	1,082	1,099	1,120	1,124	1,123	1,125	1,132	1,131	0	0	0	0

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)												Run Date: 09/18/92
LOWER 48 ENERGY DEMAND												Run Time: 03:13 PM
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,266	3,280	3,295	3,309	3,343	3,377	3,413	3,448	3,485
DISTILLATE OIL	1,165	898	877	901	906	905	900	894	885	873	858	843
LPG	400	364	358	363	367	369	369	368	366	362	357	352
COAL	58	62	58	61	61	60	60	60	59	59	58	58
NATURAL GAS	4,900	4,497	4,700	4,877	4,893	4,914	4,944	4,935	4,913	4,877	4,853	4,826
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,960	9,245	9,468	9,507	9,543	9,582	9,599	9,600	9,583	9,576	9,564
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,948	2,972	2,996	3,019	3,048	3,074	3,100	3,123	3,144
DISTILLATE OIL	561	518	509	522	524	525	518	517	515	513	511	512
LPG	70	65	63	65	64	63	62	61	61	60	60	60
COAL	88	94	88	94	94	93	92	91	90	89	89	89
NATURAL GAS	2,771	2,729	2,847	2,861	2,851	2,868	2,892	2,914	2,928	2,952	3,022	3,117
RESIDUAL OIL	228	226	223	220	214	210	207	202	197	192	189	188
TOTAL FUELS	6,472	6,494	6,654	6,710	6,719	6,756	6,790	6,833	6,865	6,907	6,993	7,108
INDUSTRIAL END USES *												
NATURAL GAS	6,949	7,060	7,394	7,370	7,432	7,374	7,305	7,064	6,997	6,953	6,865	6,771
HIGH SULFUR RESID	311	289	248	269	252	248	236	352	309	347	374	400
LOW SULFUR RESID	301	286	251	299	269	268	262	361	434	469	472	509
DISTILLATE	1,134	1,168	1,104	1,093	1,092	1,087	960	941	939	933	920	909
ELECTRICITY	3,135	3,212	3,195	3,226	3,257	3,287	3,319	3,364	3,430	3,492	3,554	3,620
COAL	1,640	1,641	1,601	1,600	1,593	1,572	1,552	1,546	1,541	1,545	1,543	1,558
TOTAL FUELS	13,471	13,655	13,794	13,857	13,896	13,836	13,633	13,628	13,651	13,737	13,728	13,766
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,884	2,870	2,885	2,994	2,928	3,039	2,975	2,994	3,317
HIGH SULFUR RESID	590	490	477	555	465	483	469	581	566	576	589	497
LOW SULFUR RESID	858	671	634	598	650	664	709	706	650	709	757	646
DISTILLATE	130	57	67	73	79	86	94	102	110	126	143	145
COAL	15,842	16,067	16,009	16,031	16,188	16,167	16,183	16,254	16,447	16,540	16,657	16,674
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,797	9,960	10,024	10,121	10,135	10,226	10,239	10,329
TOTAL FUELS	28,733	29,381	29,664	29,840	30,048	30,245	30,473	30,691	30,948	31,153	31,377	31,608
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,428	17,139	17,846	17,991	18,046	18,041	18,135	17,841	17,878	17,756	17,734	18,031
HIGH SULFUR RESID	901	778	725	824	717	731	705	932	876	922	962	897
LOW SULFUR RESID	1,387	1,184	1,108	1,117	1,133	1,143	1,177	1,269	1,281	1,370	1,418	1,343
DISTILLATE	2,989	2,641	2,557	2,589	2,601	2,603	2,472	2,453	2,449	2,445	2,432	2,408
COAL	17,628	17,864	17,757	17,786	17,935	17,893	17,888	17,951	18,137	18,233	18,347	18,378
ALL OTHER FUELS	8,975	9,672	9,993	10,127	10,228	10,392	10,454	10,550	10,562	10,649	10,656	10,741
TOTAL FUELS	49,308	49,278	49,986	50,434	50,660	50,802	50,831	50,997	51,182	51,375	51,549	51,797

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

Run Time: 03:13 PM

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,521	3,557	3,598	3,637	3,674	3,718	3,759	3,798	3,836	3,880	0	0	0	0
DISTILLATE OIL	828	815	801	787	773	758	746	734	724	712	0	0	0	0
LPG	348	343	339	334	330	324	320	316	313	309	0	0	0	0
COAL	57	57	57	56	56	55	55	54	54	53	0	0	0	0
NATURAL GAS	4,809	4,801	4,795	4,795	4,803	4,795	4,786	4,771	4,771	4,767	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,564	9,573	9,589	9,608	9,635	9,650	9,666	9,673	9,698	9,721	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,170	3,197	3,229	3,259	3,288	3,330	3,368	3,403	3,440	3,483	0	0	0	0
DISTILLATE OIL	514	515	516	516	516	510	511	508	506	498	0	0	0	0
LPG	60	60	59	59	59	58	58	57	57	56	0	0	0	0
COAL	89	89	89	89	89	88	88	87	87	85	0	0	0	0
NATURAL GAS	3,245	3,370	3,504	3,639	3,787	3,896	4,004	4,098	4,187	4,252	0	0	0	0
RESIDUAL OIL	187	186	186	186	187	186	186	184	182	178	0	0	0	0
TOTAL FUELS	7,264	7,417	7,584	7,749	7,927	8,068	8,214	8,338	8,459	8,552	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	6,819	6,831	6,853	6,895	6,919	6,835	6,624	6,643	6,606	6,432	0	0	0	0
HIGH SULFUR RESID	357	344	299	250	211	196	259	205	195	223	0	0	0	0
LOW SULFUR RESID	457	432	398	360	321	291	337	293	271	296	0	0	0	0
DISTILLATE	911	912	912	916	920	911	892	895	893	875	0	0	0	0
ELECTRICITY	3,687	3,755	3,849	3,906	3,975	4,062	4,243	4,217	4,307	4,475	0	0	0	0
COAL	1,556	1,554	1,550	1,538	1,527	1,509	1,527	1,506	1,494	1,498	0	0	0	0
TOTAL FUELS	13,787	13,827	13,861	13,864	13,871	13,805	13,882	13,759	13,766	13,798	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	3,510	3,706	3,921	4,035	4,172	4,354	4,668	4,699	4,897	5,162	0	0	0	0
HIGH SULFUR RESID	467	431	381	330	273	306	358	318	315	352	0	0	0	0
LOW SULFUR RESID	570	528	522	535	528	549	535	548	554	546	0	0	0	0
DISTILLATE	147	150	153	156	206	162	168	169	172	178	0	0	0	0
COAL	16,906	17,107	17,354	17,559	17,754	18,010	18,359	18,429	18,639	19,023	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,282	10,248	10,219	10,191	10,163	10,141	10,117	10,093	10,070	10,050	0	0	0	0
TOTAL FUELS	31,882	32,169	32,549	32,805	33,096	33,522	34,205	34,256	34,648	35,311	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	18,383	18,707	19,073	19,363	19,681	19,880	20,082	20,211	20,462	20,611	0	0	0	0
HIGH SULFUR RESID	824	775	679	580	483	502	617	523	511	575	0	0	0	0
LOW SULFUR RESID	1,214	1,146	1,107	1,081	1,036	1,026	1,058	1,025	1,007	1,020	0	0	0	0
DISTILLATE	2,400	2,392	2,382	2,374	2,415	2,342	2,316	2,306	2,295	2,262	0	0	0	0
COAL	18,608	18,808	19,049	19,242	19,426	19,662	20,029	20,077	20,273	20,660	0	0	0	0
ALL OTHER FUELS	10,689	10,651	10,618	10,584	10,552	10,523	10,496	10,467	10,440	10,415	0	0	0	0
TOTAL FUELS	52,118	52,477	52,907	53,224	53,592	53,934	54,597	54,608	54,988	55,543	0	0	0	0

NPCLOPPA: NPC UPSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

Run Time: 03:13 PM

AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
LDC GAS TARIFF PRICES												
AVERAGE ACQUISITION	1.76	1.73	1.57	1.54	1.52	1.63	1.63	1.90	2.01	2.19	2.33	2.46
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.41	2.50	2.49	2.77	2.89	3.10	3.24	3.35
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.21	5.16	5.26	5.25	5.56	5.68	5.91	6.05	6.16
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.33	4.28	4.37	4.36	4.67	4.79	5.02	5.16	5.27
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.73	2.72	2.84	2.90	3.25	3.42	3.72	3.86	3.95
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.58	2.72	2.76	3.09	3.21	3.44	3.59	3.70
END USER CARRIAGE PRICES												
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.33	1.42	1.44	1.70	1.80	1.98	2.11	2.22
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.60	1.71	1.74	1.95	2.02	2.19	2.32	2.42
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	1.90	2.01	2.01	2.13	2.21	2.37	2.50	2.61
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.62	2.58	2.67	2.66	2.96	3.08	3.30	3.44	3.56

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE ACQUISITION	2.47	2.49	2.47	2.39	2.38	2.39	2.46	2.41	2.52	2.56	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.33	3.32	3.27	3.15	3.12	3.11	3.15	3.08	3.18	3.21	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.11	6.09	6.01	5.88	5.81	5.79	5.82	5.74	5.83	5.84	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.23	5.22	5.15	5.02	4.96	4.94	4.97	4.90	4.99	5.01	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	3.91	3.88	3.80	3.65	3.59	3.58	3.63	3.56	3.68	3.71	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	3.67	3.65	3.58	3.45	3.40	3.38	3.43	3.35	3.45	3.49	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.23	2.27	2.27	2.18	2.20	2.22	2.29	2.26	2.38	2.43	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.43	2.46	2.46	2.40	2.43	2.47	2.51	2.49	2.61	2.65	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	2.60	2.64	2.64	2.58	2.62	2.66	2.70	2.73	2.82	2.86	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	3.53	3.53	3.47	3.35	3.31	3.30	3.35	3.28	3.38	3.41	0.00	0.00	0.00	0.00

CASE 6

NPC Downside Option Case Versus Low Reference Case

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

Run Time: 03:07 PM

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,821	89.9	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,355	106.3	82.7	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,105	17,367	75.5	82.9	1.03	1.26
1992	17.66	1.32	1.49	1.47	43.4	13,667	17,540	77.9	85.4	1.03	1.30
1993	16.90	1.36	1.53	1.48	46.8	11,965	17,498	68.4	87.9	1.07	1.30
1994	16.17	1.50	1.66	1.58	53.6	10,949	17,237	63.5	91.3	1.08	1.41
1995	15.50	1.64	1.81	1.71	61.4	10,945	16,986	64.4	94.1	1.11	1.51
1996	15.77	1.85	2.02	1.90	68.2	11,216	16,389	68.4	94.8	1.16	1.63
1997	16.06	1.95	2.12	1.99	70.5	12,402	16,152	76.8	95.4	1.16	1.72
1998	16.36	2.10	2.27	2.14	74.5	12,783	15,977	80.0	95.5	1.17	1.83
1999	16.67	2.23	2.39	2.27	77.5	13,156	15,773	83.4	95.8	1.17	1.95
2000	17.00	2.37	2.54	2.43	81.0	14,073	15,710	89.6	95.8	1.17	2.06
2001	17.30	2.47	2.63	2.53	82.7	14,790	15,769	93.8	95.8	1.20	2.10
2002	17.59	2.51	2.67	2.57	82.6	15,110	15,877	95.2	95.9	1.21	2.12
2003	17.90	2.55	2.72	2.62	82.8	15,183	15,909	95.4	95.9	1.22	2.13
2004	18.19	2.60	2.76	2.66	82.8	15,617	16,008	97.6	95.9	1.21	2.18
2005	18.50	2.66	2.83	2.72	83.5	15,491	16,052	96.5	95.8	1.21	2.24
2006	18.79	2.73	2.90	2.78	84.4	15,118	15,952	94.8	95.8	1.21	2.31
2007	19.10	2.81	2.98	2.86	85.4	14,892	15,811	94.2	95.8	1.20	2.38
2008	19.40	2.89	3.06	2.93	86.4	15,071	15,705	96.0	95.8	1.21	2.43
2009	19.69	2.95	3.12	3.00	87.0	14,876	15,583	95.5	95.8	1.21	2.49
2010	20.00	3.00	3.17	3.03	87.0	15,036	15,541	96.8	95.8	1.20	2.55
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

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LOWER 48 NATURAL GAS BALANCE

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
DEMAND														
RESIDENTIAL	4,900	4,497	4,700	4,877	4,893	4,912	4,938	4,913	4,891	4,851	4,830	4,796		
COMMERCIAL *	2,771	2,729	2,847	2,859	2,846	2,858	2,865	2,846	2,822	2,797	2,809	2,832		
INDUSTRIAL	6,949	7,060	7,394	7,370	7,432	7,361	7,198	6,981	6,891	6,843	6,731	6,529		
BOILERS	2,791	2,831	2,985	2,901	2,918	2,887	2,805	2,675	2,602	2,570	2,494	2,361		
NONBOILERS	4,158	4,229	4,409	4,470	4,514	4,474	4,393	4,307	4,290	4,273	4,237	4,168		
ELECTRIC UTILITY	2,808	2,852	2,905	2,884	2,868	2,868	2,905	2,840	2,890	2,817	2,764	3,004		
TOTAL END USE DEMAND	17,428	17,139	17,846	17,990	18,039	17,998	17,906	17,580	17,495	17,307	17,134	17,161		
LEASE AND PLANT USE	886	1,061	1,094	1,106	1,100	1,081	1,064	1,025	1,009	998	984	980		
TRANSMISSION FUEL	655	644	671	676	678	677	673	661	658	651	644	645		
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547		
TOTAL DISPOSITION	19,148	19,017	19,869	20,092	20,206	20,187	20,105	19,749	19,861	19,471	19,294	19,334		
SUPPLY														
LOWER-48 PRODUCTION	17,661	17,356	17,959	18,047	18,004	17,727	17,534	16,923	16,675	16,489	16,296	16,230		
PIPELINE IMPORTS	1,327	1,466	1,709	1,841	1,996	2,249	2,448	2,590	2,693	2,632	2,576	2,559		
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0		
LNG + SNG + SUPPLEMENTALS	153	191	197	199	199	199	223	327	381	438	510	628		
TOTAL GAS SUPPLY	19,141	19,013	19,865	20,086	20,199	20,175	20,205	19,839	19,749	19,558	19,382	19,417		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,767	4,743	4,727	4,713	4,705	4,684	4,670	4,652	4,639	4,634	0	0	0	0
COMMERCIAL *	2,862	2,889	2,929	2,967	3,015	3,027	3,048	3,055	3,051	3,032	0	0	0	0
INDUSTRIAL	6,478	6,430	6,375	6,326	6,243	6,121	6,001	5,902	5,816	5,749	0	0	0	0
BOILERS	2,351	2,335	2,312	2,290	2,249	2,186	2,108	2,048	1,996	1,963	0	0	0	0
NONBOILERS	4,127	4,095	4,063	4,036	3,994	3,935	3,893	3,854	3,820	3,786	0	0	0	0
ELECTRIC UTILITY	3,115	3,230	3,313	3,424	3,511	3,581	3,621	3,673	3,762	3,860	0	0	0	0
TOTAL END USE DEMAND	17,222	17,291	17,343	17,431	17,475	17,414	17,340	17,282	17,268	17,275	0	0	0	0
LEASE AND PLANT USE	983	989	991	996	997	990	980	972	962	958	0	0	0	0
TRANSMISSION FUEL	648	650	652	655	657	655	652	650	649	650	0	0	0	0
UAF + EXPORTS	563	579	600	622	643	664	680	696	712	728	0	0	0	0
TOTAL DISPOSITION	19,415	19,510	19,588	19,704	19,772	19,722	19,651	19,600	19,592	19,610	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	16,243	16,374	16,403	16,502	16,545	16,434	16,280	16,163	16,029	15,976	0	0	0	0
PIPELINE IMPORTS	2,535	2,496	2,538	2,557	2,577	2,622	2,692	2,748	2,875	2,947	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	681	683	686	683	690	697	703	704	702	697	0	0	0	0
TOTAL GAS SUPPLY	19,459	19,553	19,626	19,742	19,811	19,754	19,675	19,615	19,606	19,620	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92
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ENERGY DEMAND FOR COMBUSTION USES
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,428	17,139	17,846	17,990	18,039	17,998	17,906	17,580	17,495	17,307	17,134	17,161
RESIDUAL FUEL OIL	2,288	1,962	1,833	1,941	1,847	1,874	2,012	2,244	2,279	2,399	2,623	2,620
DISTILLATE FUEL OIL	2,989	2,641	2,557	2,589	2,601	2,601	2,468	2,447	2,446	2,440	2,430	2,401
LPG (RES/COM SECTORS)	470	429	420	428	431	432	432	430	428	423	419	414
COAL (EXCLUDES COKING COAL)	17,628	17,864	17,757	17,788	17,937	17,907	17,929	18,024	18,277	18,419	18,543	18,661
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,130	3,155	3,155	3,159	3,163	3,167	3,170	3,173
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,278	49,986	50,434	50,661	50,781	50,780	50,846	51,061	51,215	51,389	51,587
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,440	9,512	9,583	9,657	9,772	9,918	10,051	10,182	10,319
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,841)	(30,054)	(30,251)	(30,474)	(30,696)	(31,005)	(31,241)	(31,485)	(31,745)
END USE ENERGY DEMAND	29,515	29,109	29,693	30,033	30,119	30,113	29,963	29,922	29,974	30,024	30,087	30,161

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	17,222	17,291	17,343	17,431	17,475	17,414	17,340	17,282	17,268	17,275	0	0	0	0
RESIDUAL FUEL OIL	2,572	2,470	2,379	2,323	2,298	2,355	2,449	2,496	2,508	2,478	0	0	0	0
DISTILLATE FUEL OIL	2,390	2,373	2,406	2,390	2,373	2,299	2,280	2,262	2,242	2,223	0	0	0	0
LPG (RES/COM SECTORS)	410	406	401	397	393	388	384	380	376	372	0	0	0	0
COAL (EXCLUDES COKING COAL)	18,945	19,259	19,556	19,822	20,094	20,373	20,646	20,927	21,226	21,619	0	0	0	0
HYDRO/RENEWABLES	3,185	3,207	3,231	3,255	3,281	3,310	3,338	3,366	3,396	3,427	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	51,830	52,062	52,321	52,572	52,817	52,990	53,239	53,465	53,718	54,046	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,467	10,611	10,761	10,911	11,055	11,212	11,368	11,518	11,684	11,878	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(32,073)	(32,392)	(32,720)	(33,047)	(33,379)	(33,764)	(34,140)	(34,494)	(34,894)	(35,383)	0	0	0	0
END USE ENERGY DEMAND	30,224	30,281	30,363	30,436	30,492	30,438	30,468	30,490	30,508	30,541	0	0	0	0

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)												Run Date: 09/18/92
Run Time: 03:07 PM												
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,266	3,280	3,295	3,310	3,345	3,382	3,418	3,454	3,491
DISTILLATE OIL	1,165	898	877	901	906	905	902	894	886	873	860	845
LPG	400	364	358	363	367	369	370	368	367	363	359	354
COAL	58	62	58	61	60	60	60	60	59	59	59	58
NATURAL GAS	4,900	4,497	4,700	4,877	4,893	4,912	4,938	4,913	4,891	4,851	4,830	4,796
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,960	9,245	9,468	9,507	9,541	9,579	9,579	9,586	9,564	9,561	9,544
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,949	2,975	3,000	3,027	3,060	3,097	3,132	3,168	3,205
DISTILLATE OIL	561	518	509	522	524	525	522	520	520	517	516	519
LPG	70	65	63	65	64	63	62	62	61	61	61	61
COAL	88	94	88	94	94	93	93	91	91	90	89	89
NATURAL GAS	2,771	2,729	2,847	2,859	2,846	2,858	2,865	2,846	2,822	2,797	2,809	2,832
RESIDUAL OIL	228	226	223	220	214	210	206	201	196	191	189	187
TOTAL FUELS	6,472	6,494	6,654	6,709	6,716	6,749	6,774	6,779	6,787	6,787	6,831	6,892
INDUSTRIAL END USES *												
NATURAL GAS	6,949	7,060	7,394	7,370	7,432	7,361	7,198	6,981	6,891	6,843	6,731	6,529
HIGH SULFUR RESID	311	289	248	268	252	247	277	363	335	372	428	492
LOW SULFUR RESID	301	286	251	299	269	269	311	374	466	491	522	621
DISTILLATE	1,134	1,168	1,104	1,093	1,092	1,085	951	931	929	922	909	889
ELECTRICITY	3,135	3,212	3,195	3,226	3,257	3,288	3,321	3,368	3,440	3,501	3,561	3,623
COAL	1,640	1,641	1,601	1,600	1,593	1,572	1,552	1,547	1,541	1,545	1,544	1,572
TOTAL FUELS	13,471	13,655	13,794	13,857	13,896	13,822	13,610	13,563	13,602	13,674	13,694	13,724
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,884	2,868	2,868	2,905	2,840	2,890	2,817	2,764	3,004
HIGH SULFUR RESID	590	490	477	555	463	483	547	585	581	584	627	509
LOW SULFUR RESID	858	671	634	599	649	665	672	723	702	761	859	812
DISTILLATE	130	57	67	73	79	86	94	102	111	128	145	148
COAL	15,842	16,067	16,009	16,032	16,189	16,181	16,225	16,326	16,586	16,725	16,852	16,942
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,806	9,969	10,033	10,121	10,136	10,227	10,240	10,330
TOTAL FUELS	28,733	29,381	29,664	29,841	30,054	30,251	30,474	30,696	31,005	31,241	31,485	31,745
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,428	17,139	17,846	17,990	18,039	17,998	17,906	17,580	17,495	17,307	17,134	17,161
HIGH SULFUR RESID	901	778	725	823	715	730	823	947	916	956	1,055	1,000
LOW SULFUR RESID	1,387	1,184	1,108	1,118	1,132	1,144	1,189	1,297	1,363	1,443	1,569	1,620
DISTILLATE	2,989	2,641	2,557	2,589	2,601	2,601	2,468	2,447	2,446	2,440	2,430	2,401
COAL	17,628	17,864	17,757	17,788	17,937	17,907	17,929	18,024	18,277	18,419	18,543	18,661
ALLOTHER FUELS	8,975	9,672	9,993	10,127	10,237	10,401	10,465	10,551	10,564	10,650	10,659	10,744
TOTAL FUELS	49,308	49,278	49,986	50,434	50,661	50,780	50,780	50,846	51,061	51,214	51,389	51,586

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)											Run Date: 09/18/92				
											Run Time: 03:07 PM				
LOWER 48 ENERGY DEMAND															
(Trillion Btus)															
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030	
RESIDENTIAL END USES															
ELECTRICITY	3,529	3,567	3,605	3,645	3,682	3,722	3,763	3,802	3,843	3,885	0	0	0	0	
DISTILLATE OIL	831	817	804	790	778	764	752	740	728	718	0	0	0	0	
LPG	349	345	340	336	332	327	323	319	316	313	0	0	0	0	
COAL	58	57	57	56	56	55	55	54	54	53	0	0	0	0	
NATURAL GAS	4,767	4,743	4,727	4,713	4,705	4,684	4,670	4,652	4,639	4,634	0	0	0	0	
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
TOTAL FUELS	9,533	9,528	9,533	9,540	9,552	9,552	9,562	9,567	9,580	9,603	0	0	0	0	
COMMERCIAL END USES															
ELECTRICITY	3,250	3,294	3,340	3,386	3,431	3,483	3,537	3,588	3,643	3,698	0	0	0	0	
DISTILLATE OIL	523	526	529	532	536	535	536	535	533	528	0	0	0	0	
LPG	61	61	61	61	61	61	61	61	60	60	0	0	0	0	
COAL	90	90	90	90	91	90	90	90	89	88	0	0	0	0	
NATURAL GAS	2,862	2,889	2,929	2,967	3,015	3,027	3,048	3,055	3,051	3,032	0	0	0	0	
RESIDUAL OIL	186	185	185	184	184	183	182	180	178	176	0	0	0	0	
TOTAL FUELS	6,971	7,044	7,133	7,221	7,318	7,379	7,454	7,510	7,555	7,582	0	0	0	0	
INDUSTRIAL END USES *															
NATURAL GAS	6,478	6,430	6,375	6,326	6,243	6,121	6,001	5,902	5,816	5,749	0	0	0	0	
HIGH SULFUR RESID	498	492	468	462	449	437	455	456	454	431	0	0	0	0	
LOW SULFUR RESID	596	585	593	576	566	553	567	578	577	558	0	0	0	0	
DISTILLATE	883	876	869	861	852	837	827	818	809	801	0	0	0	0	
ELECTRICITY	3,688	3,750	3,816	3,880	3,942	4,007	4,069	4,128	4,197	4,295	0	0	0	0	
COAL	1,575	1,575	1,575	1,569	1,570	1,551	1,533	1,531	1,520	1,522	0	0	0	0	
TOTAL FUELS	13,719	13,708	13,696	13,674	13,621	13,506	13,453	13,413	13,373	13,356	0	0	0	0	
ELECTRIC UTILITY ENERGY INPUT															
NATURAL GAS	3,115	3,230	3,313	3,424	3,511	3,581	3,621	3,673	3,762	3,860	0	0	0	0	
HIGH SULFUR RESID	504	474	430	419	416	456	469	470	475	476	0	0	0	0	
LOW SULFUR RESID	787	734	704	682	684	726	776	812	824	837	0	0	0	0	
DISTILLATE	153	154	205	207	207	163	166	169	172	176	0	0	0	0	
COAL	17,222	17,537	17,834	18,107	18,378	18,676	18,968	19,252	19,563	19,955	0	0	0	0	
NUCLEAR/HYDRO/OTHER	10,291	10,262	10,235	10,209	10,184	10,162	10,140	10,118	10,098	10,079	0	0	0	0	
TOTAL FUELS	32,073	32,392	32,720	33,047	33,379	33,764	34,140	34,494	34,894	35,383	0	0	0	0	
PRIMARY ENERGY CONSUMPTION															
NATURAL GAS	17,222	17,291	17,343	17,431	17,475	17,414	17,340	17,282	17,268	17,275	0	0	0	0	
HIGH SULFUR RESID	1,003	966	898	881	865	893	924	927	929	907	0	0	0	0	
LOW SULFUR RESID	1,570	1,505	1,481	1,442	1,433	1,461	1,525	1,570	1,579	1,571	0	0	0	0	
DISTILLATE	2,390	2,373	2,406	2,390	2,373	2,299	2,280	2,262	2,242	2,223	0	0	0	0	
COAL	18,945	19,259	19,556	19,822	20,094	20,373	20,646	20,927	21,226	21,619	0	0	0	0	
ALL OTHER FUELS	10,701	10,668	10,636	10,606	10,577	10,550	10,524	10,498	10,474	10,451	0	0	0	0	
TOTAL FUELS	51,830	52,061	52,321	52,572	52,817	52,990	53,239	53,465	53,718	54,046	0	0	0	0	

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (# TABLE 2: LOWER 48 WELLS AND RESERVES)											Run Date: 09/18/92	
											Run Time: 03:07 PM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,567	4,448	3,629	3,255	3,256	3,471	3,660	4,070	4,990	5,976
DEVELOPMENT WELLS	22,582	27,158	26,414	20,364	16,805	14,875	15,553	15,736	15,158	16,061	19,707	22,208
TOTAL GAS WELLS	9,472	10,333	9,899	7,532	6,529	6,582	6,507	7,389	7,265	7,719	7,152	7,962
TOTAL WELLS	28,326	33,314	31,981	24,812	20,435	18,130	18,809	19,207	18,818	20,131	24,697	28,185
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	936	1,657	1,355	1,045	875	828	798	846	981	995
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,012	1,844	1,500	1,191	1,015	1,020	1,017	1,058	1,240	1,255
HIGH PERMEABILITY (BCF)	9,905	12,223	7,432	7,986	7,449	7,089	7,415	7,621	9,158	9,418	9,290	10,152
LOW PERMEABILITY (BCF)	1,339	1,691	1,532	1,798	1,030	809	574	734	802	1,006	1,195	1,197
DEVONIAN SHALE (BCF)	384	504	397	315	318	327	358	377	421	473	532	483
COAL BED METHANE (BCF)	1,607	2,111	2,386	1,411	1,399	1,315	1,358	1,236	742	518	510	492
ENHANCED RECOVERY GAS (BCF)	443	303	296	179	147	138	135	142	163	194	237	296
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	133	121	81	92	87	99	116	152	198
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,093	11,823	10,465	9,758	9,931	10,197	11,385	11,725	11,916	12,818
TOTAL OIL (MMB)	1,194	1,388	936	1,657	1,355	1,045	875	828	798	846	981	995
TOTAL GAS (BCF)	15,127	18,454	13,105	13,667	11,965	10,949	10,945	11,216	12,402	12,783	13,156	14,073
TOTAL NGL (MMB)	550	681	432	526	456	415	406	433	494	525	546	598
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,722	1,700	1,639	1,573	1,531	1,490	1,452	1,428	1,410
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,481	2,361	2,189	2,062	1,976	1,917	1,848	1,782	1,734
HIGH PERMEABILITY (BCF)	12,041	12,440	12,386	12,349	12,331	12,174	11,991	11,500	11,326	11,178	10,977	10,905
LOW PERMEABILITY (BCF)	1,666	1,675	1,701	1,850	1,798	1,722	1,659	1,565	1,473	1,472	1,498	1,529
DEVONIAN SHALE (BCF)	152	180	211	225	236	251	271	271	288	299	311	326
COAL BED METHANE (BCF)	103	178	285	422	546	673	770	859	943	970	979	956
ENHANCED RECOVERY GAS (BCF)	83	114	138	162	163	162	163	150	134	137	150	174
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	51	62	66	69	68	71	73	76	86
TOTAL NON-ASSOC GAS (BCF)	14,091	14,634	14,768	15,059	15,136	15,048	14,924	14,413	14,235	14,129	13,990	13,976
TOTAL OIL (MMB)	1,871	1,782	1,751	1,722	1,700	1,639	1,573	1,531	1,490	1,452	1,428	1,410
TOTAL GAS (BCF)	16,821	17,355	17,367	17,540	17,498	17,237	16,986	16,389	16,152	15,977	15,773	15,710
TOTAL NGL (MMB)	740	752	748	757	753	735	721	696	689	684	677	674
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,854	18,789	18,445	17,851	17,153	16,450	15,759	15,152	14,705	14,291
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,303	21,666	20,804	19,806	18,758	17,802	16,903	16,112	15,570	15,091
HIGH PERMEABILITY (BCF)	105,413	105,196	100,344	95,981	91,099	86,015	81,438	77,559	75,392	73,632	71,945	71,192
LOW PERMEABILITY (BCF)	22,835	22,851	22,704	22,652	21,884	20,971	19,886	19,054	18,383	17,917	17,614	17,283
DEVONIAN SHALE (BCF)	1,751	2,076	2,262	2,353	2,434	2,511	2,598	2,703	2,836	3,010	3,230	3,387
COAL BED METHANE (BCF)	2,798	4,731	6,833	7,822	8,675	9,317	9,905	10,282	10,080	9,628	9,160	8,695
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,310	1,328	1,313	1,286	1,258	1,251	1,280	1,337	1,424	1,546
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	618	676	691	714	733	762	805	880	992
TOTAL NON-ASSOC GAS (BCF)	134,266	136,540	133,989	130,753	126,082	120,792	115,799	111,582	108,732	106,328	104,254	103,095
TOTAL OIL (MMB)	20,063	19,670	18,854	18,789	18,445	17,851	17,153	16,450	15,759	15,152	14,705	14,291
TOTAL GAS (BCF)	159,307	160,406	156,292	152,419	146,888	140,598	134,557	129,384	125,635	122,440	119,823	118,186
TOTAL NGL (MMB)	7,499	7,429	7,113	6,882	6,585	6,264	5,949	5,686	5,491	5,333	5,202	5,126
LEASE AND PLANT GAS (BCF)												
	857	1,027	1,060	1,071	1,066	1,047	1,030	993	977	966	953	949

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (# TABLE 2: LOWER 48 WELLS AND RESERVES)											Run Date: 09/18/92 Run Time: 03:07 PM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	6,866	6,874	6,661	6,638	6,848	7,148	7,388	7,499	7,130	6,721	0	0	0	0
DEVELOPMENT WELLS	24,334	24,570	22,306	22,227	22,047	22,125	20,979	21,396	20,394	19,602	0	0	0	0
TOTAL GAS WELLS	8,668	9,390	9,382	9,432	9,335	9,497	9,255	9,490	9,487	10,034	0	0	0	0
TOTAL WELLS	31,201	31,445	28,966	28,865	28,895	29,273	28,366	28,894	27,524	26,323	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,077	1,046	985	976	977	898	800	852	784	679	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,349	1,336	1,286	1,258	1,239	1,139	1,045	1,047	970	872	0	0	0	0
HIGH PERMEABILITY (BCF)	10,675	10,851	10,957	10,777	10,507	9,986	9,865	9,927	9,444	9,244	0	0	0	0
LOW PERMEABILITY (BCF)	1,264	1,347	1,296	1,449	1,474	1,532	1,413	1,334	1,331	1,466	0	0	0	0
DEVONIAN SHALE (BCF)	412	453	488	527	445	392	362	341	291	263	0	0	0	0
COAL BED METHANE (BCF)	464	406	355	416	526	642	702	748	869	954	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	370	414	440	553	563	549	433	386	401	362	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	255	304	362	637	738	878	1,072	1,288	1,570	1,874	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	13,441	13,774	13,897	14,359	14,253	13,979	13,848	14,024	13,907	14,164	0	0	0	0
TOTAL OIL (MMB)	1,077	1,046	985	976	977	898	800	852	784	679	0	0	0	0
TOTAL GAS (BCF)	14,790	15,110	15,183	15,617	15,491	15,118	14,892	15,071	14,876	15,036	0	0	0	0
TOTAL NGL (MMB)	640	647	639	634	620	587	569	578	552	535	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,397	1,389	1,380	1,365	1,349	1,330	1,306	1,281	1,255	1,219	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,703	1,674	1,652	1,626	1,605	1,569	1,536	1,494	1,451	1,400	0	0	0	0
HIGH PERMEABILITY (BCF)	10,943	11,032	11,060	11,118	11,108	11,003	10,853	10,771	10,593	10,474	0	0	0	0
LOW PERMEABILITY (BCF)	1,550	1,575	1,584	1,587	1,603	1,588	1,564	1,522	1,503	1,500	0	0	0	0
DEVONIAN SHALE (BCF)	333	334	337	350	360	359	358	352	347	341	0	0	0	0
COAL BED METHANE (BCF)	930	894	859	833	793	772	768	758	771	791	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	206	246	274	310	346	364	366	361	371	371	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	103	121	143	183	238	297	366	448	547	665	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	14,066	14,202	14,258	14,381	14,447	14,383	14,275	14,211	14,132	14,141	0	0	0	0
TOTAL OIL (MMB)	1,397	1,389	1,380	1,365	1,349	1,330	1,306	1,281	1,255	1,219	0	0	0	0
TOTAL GAS (BCF)	15,769	15,877	15,909	16,008	16,052	15,952	15,811	15,705	15,583	15,541	0	0	0	0
TOTAL NGL (MMB)	676	681	681	679	677	669	658	647	639	632	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	13,970	13,627	13,232	12,843	12,471	12,039	11,533	11,103	10,632	10,092	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	14,737	14,398	14,033	13,664	13,298	12,868	12,377	11,929	11,448	10,921	0	0	0	0
HIGH PERMEABILITY (BCF)	70,925	70,743	70,640	70,300	69,699	68,682	67,694	66,850	65,702	64,472	0	0	0	0
LOW PERMEABILITY (BCF)	16,997	16,768	16,480	16,341	16,212	16,157	16,006	15,819	15,647	15,613	0	0	0	0
DEVONIAN SHALE (BCF)	3,466	3,584	3,735	3,911	3,997	4,029	4,033	4,023	3,967	3,888	0	0	0	0
COAL BED METHANE (BCF)	8,229	7,741	7,236	6,819	6,553	6,423	6,357	6,347	6,444	6,608	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	1,710	1,878	2,044	2,287	2,504	2,689	2,756	2,781	2,811	2,803	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	1,145	1,327	1,545	2,000	2,499	3,080	3,786	4,626	5,649	6,858	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	102,470	102,042	101,681	101,659	101,464	101,060	100,632	100,445	100,220	100,242	0	0	0	0
TOTAL OIL (MMB)	13,970	13,627	13,232	12,843	12,471	12,039	11,533	11,103	10,632	10,092	0	0	0	0
TOTAL GAS (BCF)	117,207	116,440	115,714	115,323	114,762	113,928	113,009	112,375	111,668	111,163	0	0	0	0
TOTAL NGL (MMB)	5,090	5,056	5,014	4,969	4,912	4,831	4,741	4,673	4,586	4,490	0	0	0	0
LEASE AND PLANT GAS (BCF)	952	958	959	964	966	958	949	941	932	927	0	0	0	0

NPCLOPMA: NPC DOWNSIDE OPTION CASE VS LOW REFERENCE CASE (#3)

Run Date: 09/18/92

Run Time: 03:07 PM

AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	1.76	1.73	1.57	1.54	1.54	1.66	1.76	1.99	2.10	2.23	2.38	2.57		
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.43	2.53	2.66	2.93	3.07	3.24	3.42	3.62		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.21	5.18	5.30	5.43	5.75	5.91	6.11	6.30	6.54		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.33	4.30	4.41	4.54	4.85	5.01	5.20	5.39	5.62		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.73	2.75	2.89	3.09	3.42	3.66	3.88	4.06	4.25		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.60	2.76	2.95	3.24	3.40	3.59	3.77	3.97		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.34	1.45	1.57	1.76	1.85	1.99	2.11	2.27		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.61	1.74	1.85	1.99	2.07	2.20	2.33	2.49		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	1.92	2.05	2.04	2.17	2.25	2.39	2.52	2.67		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.62	2.60	2.71	2.84	3.12	3.27	3.44	3.63	3.84		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	2.66	2.72	2.78	2.81	2.87	2.93	3.00	3.07	3.14	3.18	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.72	3.79	3.84	3.87	3.92	3.99	4.06	4.14	4.22	4.26	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.65	6.72	6.78	6.80	6.85	6.93	7.01	7.10	7.18	7.24	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.73	5.80	5.86	5.88	5.93	6.00	6.08	6.17	6.26	6.31	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.36	4.42	4.47	4.50	4.56	4.64	4.73	4.82	4.91	4.96	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.06	4.13	4.19	4.21	4.28	4.35	4.42	4.50	4.58	4.62	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.36	2.41	2.47	2.51	2.57	2.64	2.72	2.79	2.86	2.90	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.56	2.61	2.67	2.71	2.77	2.84	2.91	2.98	3.05	3.09	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	2.74	2.79	2.85	2.89	2.96	3.02	3.10	3.18	3.25	3.29	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	3.95	4.01	4.07	4.10	4.15	4.22	4.30	4.38	4.46	4.50	0.00	0.00	0.00	0.00

CASE 7

NPC Supply Confidence Positive Case Revised

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,811	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,340	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,211	17,345	76.2	82.8	1.02	1.27
1992	18.46	1.32	1.49	1.47	41.5	13,847	17,573	78.8	85.5	0.99	1.36
1993	18.60	1.51	1.68	1.62	47.2	13,959	17,744	78.7	88.3	0.98	1.57
1994	18.76	1.69	1.86	1.78	52.4	14,163	17,641	80.3	90.8	0.98	1.76
1995	19.01	1.96	2.13	2.02	59.8	14,772	17,715	83.4	93.4	1.00	2.01
1996	19.25	2.18	2.35	2.23	65.8	15,598	17,608	88.6	94.0	1.02	2.17
1997	19.56	2.27	2.44	2.32	67.3	16,290	17,741	91.8	94.5	1.01	2.29
1998	19.91	2.39	2.56	2.43	69.6	16,907	17,915	94.4	94.9	1.00	2.43
1999	20.51	2.52	2.69	2.57	71.2	19,023	18,177	104.7	95.1	1.00	2.57
2000	21.10	2.60	2.77	2.65	71.4	20,691	18,616	111.1	95.1	1.00	2.65
2001	21.75	2.56	2.73	2.62	68.3	21,311	19,127	111.4	94.6	0.99	2.63
2002	22.55	2.42	2.59	2.49	62.3	22,795	19,530	116.7	93.6	0.98	2.52
2003	23.45	2.26	2.43	2.33	55.8	23,298	19,842	117.4	92.1	0.98	2.35
2004	24.25	2.28	2.45	2.36	54.6	22,839	20,301	112.5	91.6	0.96	2.43
2005	25.14	2.28	2.45	2.35	52.6	23,377	20,564	113.7	91.1	0.96	2.43
2006	25.74	2.20	2.37	2.26	49.5	22,925	20,635	111.1	90.0	0.95	2.37
2007	26.25	2.21	2.38	2.25	48.8	21,961	20,766	105.8	89.8	0.94	2.41
2008	26.75	2.39	2.56	2.41	51.9	22,129	21,060	105.1	90.8	0.94	2.60
2009	27.35	2.58	2.75	2.58	54.7	21,928	21,364	102.6	91.8	0.93	2.84
2010	27.85	2.74	2.91	2.74	57.1	22,583	21,554	104.8	92.3	0.91	3.06
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2

Run Date: 09/17/92
Run Time: 11:30 AM**LOWER 48 NATURAL GAS BALANCE**
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DEMAND												
RESIDENTIAL	4,900	4,497	4,700	4,853	4,854	4,863	4,894	4,890	4,887	4,882	4,885	4,881
COMMERCIAL *	2,771	2,729	2,846	2,849	2,847	2,859	2,880	2,879	2,875	2,882	2,919	2,971
INDUSTRIAL	6,939	7,046	7,376	7,416	7,643	7,719	7,774	7,702	7,725	7,810	7,893	8,034
BOILERS	2,791	2,831	2,983	2,925	3,009	3,100	3,129	3,108	3,100	3,140	3,190	3,241
NONBOILERS	4,148	4,215	4,393	4,490	4,634	4,619	4,645	4,594	4,625	4,670	4,703	4,792
ELECTRIC UTILITY	2,808	2,852	2,905	2,898	2,904	2,942	3,058	3,162	3,355	3,497	3,691	4,003
TOTAL END USE DEMAND	17,417	17,125	17,827	18,016	18,247	18,383	18,606	18,632	18,842	19,071	19,387	19,888
LEASE AND PLANT USE	885	1,060	1,093	1,108	1,116	1,107	1,110	1,100	1,107	1,117	1,133	1,159
TRANSMISSION FUEL	655	644	670	677	686	691	700	701	708	717	729	748
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547
TOTAL DISPOSITION	19,137	19,001	19,848	20,120	20,437	20,612	20,878	20,917	21,157	21,420	21,780	22,342
SUPPLY												
LOWER-48 PRODUCTION	17,651	17,341	17,938	18,080	18,256	18,144	18,218	18,106	18,240	18,423	18,709	19,199
PIPELINE IMPORTS	1,326	1,465	1,709	1,836	1,963	2,222	2,401	2,471	2,522	2,529	2,565	2,636
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	243	322	374	446	481	482
TOTAL GAS SUPPLY	19,130	18,997	19,843	20,115	20,431	20,601	20,863	20,898	21,136	21,397	21,755	22,316

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,885	4,897	4,909	4,929	4,933	4,937	4,946	4,964	4,981	5,009	0	0	0	0
COMMERCIAL *	3,039	3,109	3,187	3,269	3,341	3,391	3,453	3,515	3,560	3,591	0	0	0	0
INDUSTRIAL	8,254	8,406	8,492	8,700	8,706	8,808	8,901	9,024	9,148	9,298	0	0	0	0
BOILERS	3,371	3,467	3,534	3,659	3,680	3,744	3,803	3,877	3,949	4,042	0	0	0	0
NONBOILERS	4,883	4,939	4,958	5,041	5,026	5,064	5,099	5,147	5,199	5,257	0	0	0	0
ELECTRIC UTILITY	4,156	4,240	4,394	4,504	4,659	4,791	4,955	5,118	5,309	5,548	0	0	0	0
TOTAL END USE DEMAND	20,334	20,652	20,981	21,401	21,639	21,927	22,255	22,621	22,997	23,447	0	0	0	0
LEASE AND PLANT USE	1,189	1,212	1,230	1,257	1,273	1,276	1,283	1,300	1,318	1,328	0	0	0	0
TRANSMISSION FUEL	765	777	789	805	814	824	837	851	865	882	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,803	23,125	23,452	23,883	24,113	24,368	24,667	25,053	25,462	25,854	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,721	20,105	20,428	20,911	21,210	21,284	21,423	21,729	22,022	22,205	0	0	0	0
PIPELINE IMPORTS	2,599	2,621	2,657	2,660	2,618	2,772	2,861	2,934	3,037	3,240	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	464	386	359	304	277	303	356	383	382	381	0	0	0	0
TOTAL GAS SUPPLY	22,784	23,112	23,444	23,875	24,105	24,360	24,859	25,045	25,442	25,826	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2

Run Date: 09/17/92

Run Time: 11:30 AM

ENERGY DEMAND FOR COMBUSTION USES

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,417	17,125	17,827	18,016	18,247	18,383	18,606	18,632	18,842	19,071	19,387	19,888
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,943	1,866	1,855	1,934	2,072	2,095	2,057	2,035	1,945
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,613	2,595	2,599	2,593	2,603	2,613	2,622	2,619
LPG (RES/COM SECTORS)	470	429	421	426	428	427	425	423	422	419	415	411
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,079	18,141	18,227	18,396	18,647	18,852	19,080	19,248
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,226
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,276	49,986	50,541	51,043	51,374	51,828	52,279	52,787	53,283	53,827	54,494
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,577	9,683	9,792	9,958	10,127	10,299	10,478	10,665
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,912)	(30,192)	(30,468)	(30,779)	(31,178)	(31,582)	(31,940)	(32,322)	(32,711)
END USE ENERGY DEMAND	29,515	29,107	29,692	30,102	30,428	30,588	30,840	31,058	31,332	31,642	31,983	32,448

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	20,334	20,652	20,981	21,401	21,639	21,927	22,255	22,621	22,997	23,447	0	0	0	0
RESIDUAL FUEL OIL	1,846	1,787	1,788	1,770	1,819	1,833	1,859	1,890	1,893	1,841	0	0	0	0
DISTILLATE FUEL OIL	2,632	2,635	2,633	2,648	2,644	2,645	2,649	2,659	2,665	2,673	0	0	0	0
LPG (RES/COM SECTORS)	407	403	400	398	395	392	390	388	385	382	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,608	19,976	20,382	20,737	21,134	21,471	21,835	22,181	22,553	23,036	0	0	0	0
HYDRO/RENEWABLES	3,249	3,280	3,311	3,343	3,376	3,409	3,443	3,477	3,512	3,559	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	55,182	55,789	56,499	57,249	57,909	58,528	59,233	59,967	60,707	61,589	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,868	11,043	11,246	11,420	11,628	11,810	12,016	12,218	12,439	12,715	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(33,177)	(33,573)	(34,063)	(34,489)	(34,999)	(35,443)	(35,961)	(36,479)	(37,051)	(37,773)	0	0	0	0
END USE ENERGY DEMAND	32,873	33,258	33,682	34,181	34,538	34,895	35,288	35,706	36,095	36,531	0	0	0	0

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2												Run Date: 09/17/92	
TABLE 2: LOWER 48 WELLS AND RESERVES												Run Time: 11:30 AM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	
EXPLORATORY WELLS	5,744	6,156	5,578	4,838	4,582	5,478	6,111	6,500	7,535	8,603	9,770	11,748	
DEVELOPMENT WELLS	22,582	27,158	26,428	22,542	22,507	26,122	29,589	29,810	32,488	33,526	34,564	38,050	
TOTAL GAS WELLS	9,472	10,333	9,905	7,650	7,613	7,606	8,809	9,523	9,861	10,782	11,788	12,778	
TOTAL WELLS	28,326	33,314	32,005	27,380	27,090	31,601	35,700	36,310	40,023	42,129	44,335	49,798	
RESERVE ADDITIONS													
OIL (MMB) CONVENTIONAL	1,194	1,388	937	1,717	1,602	1,501	1,397	1,364	1,371	1,423	1,519	1,600	
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	
ASSOCIATED GAS (BCF)	1,325	1,545	1,014	1,931	1,842	1,799	1,711	1,719	1,809	1,888	2,009	2,123	
HIGH PERMEABILITY (BCF)	9,905	12,223	7,503	8,001	8,846	9,181	9,847	10,573	11,145	11,558	13,066	13,969	
LOW PERMEABILITY (BCF)	1,339	1,691	1,535	1,790	1,093	1,039	852	967	1,234	1,297	1,419	1,672	
DEVONIAN SHALE (BCF)	384	504	401	329	345	372	510	572	664	800	945	954	
COAL BED METHANE (BCF)	1,607	2,111	2,413	1,462	1,526	1,497	1,571	1,454	885	701	722	691	
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	153	143	145	155	342	404	514	660	
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	152	154	132	135	160	210	259	348	622	
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,197	11,916	12,117	12,364	13,061	13,880	14,481	15,019	17,014	18,567	
TOTAL OIL (MMB)	1,194	1,388	937	1,717	1,602	1,501	1,397	1,364	1,371	1,423	1,519	1,600	
TOTAL GAS (BCF)	15,127	18,454	13,211	13,847	13,959	14,163	14,772	15,598	16,290	16,907	19,023	20,691	
TOTAL NGL (MMB)	550	681	435	530	525	533	547	599	658	688	779	855	
PRODUCTION (W/ LEASE & PLANT GAS)													
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,725	1,723	1,704	1,692	1,704	1,715	1,728	1,747	1,767	
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,486	2,389	2,266	2,205	2,183	2,189	2,185	2,179	2,182	
HIGH PERMEABILITY (BCF)	12,033	12,428	12,368	12,371	12,504	12,434	12,460	12,362	12,394	12,423	12,506	12,733	
LOW PERMEABILITY (BCF)	1,664	1,673	1,697	1,851	1,825	1,754	1,725	1,628	1,579	1,608	1,661	1,723	
DEVONIAN SHALE (BCF)	152	180	211	226	240	258	281	304	338	375	420	465	
COAL BED METHANE (BCF)	103	178	286	424	553	689	798	901	999	1,039	1,061	1,054	
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	165	165	166	147	149	177	225	297	
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	52	67	75	80	84	95	108	125	164	
TOTAL NON-ASSOC GAS (BCF)	14,082	14,620	14,747	15,087	15,355	15,375	15,511	15,426	15,553	15,730	15,998	16,434	
TOTAL OIL (MMB)	1,871	1,782	1,751	1,725	1,723	1,704	1,692	1,704	1,715	1,728	1,747	1,767	
TOTAL GAS (BCF)	16,811	17,340	17,345	17,573	17,744	17,641	17,715	17,608	17,741	17,915	18,177	18,616	
TOTAL NGL (MMB)	739	751	747	758	762	748	747	742	750	761	772	786	
RESERVES													
OIL (MMB) CONVENTIONAL	20,063	19,670	18,855	18,847	18,727	18,524	18,229	17,888	17,544	17,239	17,010	16,843	
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,750	21,203	20,735	20,241	19,777	19,398	19,101	18,931	18,872	
HIGH PERMEABILITY (BCF)	105,432	105,226	100,463	96,093	92,435	89,183	86,569	84,781	83,532	82,667	83,227	84,463	
LOW PERMEABILITY (BCF)	22,837	22,856	22,716	22,655	21,922	21,207	20,335	19,673	19,329	19,017	18,775	18,725	
DEVONIAN SHALE (BCF)	1,751	2,076	2,266	2,369	2,474	2,588	2,817	3,085	3,412	3,837	4,361	4,850	
COAL BED METHANE (BCF)	2,798	4,731	6,858	7,896	8,868	9,676	10,449	11,003	10,889	10,551	10,212	9,849	
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,319	1,296	1,275	1,283	1,476	1,703	1,992	2,355	
ENHANCED RECOVERY TIGHT (BCF)	506	535	537	637	724	781	836	911	1,027	1,177	1,400	1,859	
TOTAL NON-ASSOC GAS (BCF)	134,288	136,576	134,150	130,980	127,742	124,732	122,282	120,736	119,664	118,952	119,967	122,100	
TOTAL OIL (MMB)	20,063	19,670	18,855	18,847	18,727	18,524	18,229	17,888	17,544	17,239	17,010	16,843	
TOTAL GAS (BCF)	159,329	160,442	156,455	152,730	148,945	145,467	142,523	140,513	139,061	138,053	138,898	140,972	
TOTAL NGL (MMB)	7,500	7,430	7,119	6,891	6,654	6,439	6,240	6,097	6,005	5,933	5,939	6,008	
LEASE AND PLANT GAS (BCF)													
	857	1,026	1,058	1,073	1,081	1,072	1,075	1,066	1,072	1,082	1,097	1,122	

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2				TABLE 2: LOWER 48 WELLS AND RESERVES							Run Date: 09/17/92 Run Time: 11:30 AM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	13,609	15,959	19,400	21,747	23,791	24,127	24,932	25,725	27,698	26,178	0	0	0	0
DEVELOPMENT WELLS	38,575	39,269	42,164	39,327	39,776	38,161	36,919	36,099	37,417	38,260	0	0	0	0
TOTAL GAS WELLS	13,024	13,766	14,454	13,263	14,739	14,842	14,848	15,161	16,353	16,663	0	0	0	0
TOTAL WELLS	52,184	55,228	61,563	61,074	63,567	62,288	61,851	61,824	65,115	64,437	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,677	1,723	1,786	1,836	1,848	1,684	1,530	1,443	1,353	1,245	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,247	2,298	2,408	2,488	2,486	2,278	2,057	1,902	1,760	1,637	0	0	0	0
HIGH PERMEABILITY (BCF)	14,179	15,131	15,352	15,101	15,255	14,558	13,494	13,130	12,361	12,266	0	0	0	0
LOW PERMEABILITY (BCF)	1,824	2,100	2,242	2,093	2,269	2,343	2,203	2,294	2,378	2,450	0	0	0	0
DEVONIAN SHALE (BCF)	915	996	970	709	524	482	444	407	368	364	0	0	0	0
COAL BED METHANE (BCF)	651	660	682	706	837	1,023	1,223	1,348	1,423	1,543	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	747	736	592	470	471	395	219	194	98	18	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	748	874	1,053	1,273	1,534	1,847	2,321	2,855	3,539	4,306	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	19,064	20,497	20,890	20,351	20,890	20,647	19,904	20,227	20,167	20,946	0	0	0	0
TOTAL OIL (MMB)	1,677	1,723	1,786	1,836	1,848	1,684	1,530	1,443	1,353	1,245	0	0	0	0
TOTAL GAS (BCF)	21,311	22,795	23,298	22,839	23,377	22,925	21,961	22,129	21,928	22,583	0	0	0	0
TOTAL NGL (MMB)	892	950	952	913	927	880	803	772	727	727	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,794	1,824	1,858	1,893	1,926	1,943	1,939	1,919	1,887	1,842	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,202	2,225	2,264	2,308	2,357	2,379	2,380	2,364	2,310	2,266	0	0	0	0
HIGH PERMEABILITY (BCF)	13,065	13,283	13,418	13,704	13,841	13,831	13,839	13,952	14,007	13,902	0	0	0	0
LOW PERMEABILITY (BCF)	1,752	1,810	1,858	1,905	1,925	1,936	1,930	1,951	2,017	2,095	0	0	0	0
DEVONIAN SHALE (BCF)	498	520	540	554	539	515	509	507	497	471	0	0	0	0
COAL BED METHANE (BCF)	1,036	1,012	989	974	963	946	968	985	1,024	1,079	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	353	404	435	441	431	415	391	364	342	315	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	222	277	338	415	508	613	749	936	1,168	1,426	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,925	17,306	17,578	17,993	18,208	18,256	18,386	18,696	19,054	19,288	0	0	0	0
TOTAL OIL (MMB)	1,794	1,824	1,858	1,893	1,926	1,943	1,939	1,919	1,887	1,842	0	0	0	0
TOTAL GAS (BCF)	19,127	19,530	19,842	20,301	20,564	20,635	20,766	21,060	21,364	21,554	0	0	0	0
TOTAL NGL (MMB)	807	824	834	849	853	850	846	846	849	843	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	16,726	16,626	16,553	16,497	16,419	16,159	15,750	15,275	14,742	14,145	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	18,917	18,990	19,133	19,313	19,442	19,341	19,019	18,556	18,006	17,378	0	0	0	0
HIGH PERMEABILITY (BCF)	85,577	87,426	89,360	90,757	92,171	92,898	92,553	91,731	90,084	88,448	0	0	0	0
LOW PERMEABILITY (BCF)	18,797	19,086	19,470	19,658	20,003	20,409	20,682	21,024	21,385	21,740	0	0	0	0
DEVONIAN SHALE (BCF)	5,268	5,744	6,174	6,329	6,314	6,281	6,217	6,116	5,987	5,881	0	0	0	0
COAL BED METHANE (BCF)	9,464	9,112	8,804	8,536	8,409	8,486	8,740	9,103	9,502	9,966	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,749	3,081	3,238	3,267	3,307	3,286	3,114	2,944	2,700	2,403	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	2,385	2,982	3,696	4,554	5,580	6,814	8,386	10,304	12,676	15,555	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	124,239	127,430	130,743	133,101	135,784	138,174	139,691	141,222	142,335	143,993	0	0	0	0
TOTAL OIL (MMB)	16,726	16,626	16,553	16,497	16,419	16,159	15,750	15,275	14,742	14,145	0	0	0	0
TOTAL GAS (BCF)	143,156	146,420	149,876	152,414	155,226	157,516	158,710	159,778	160,341	161,371	0	0	0	0
TOTAL NGL (MMB)	6,093	6,218	6,336	6,401	6,474	6,505	6,461	6,388	6,267	6,150	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,151	1,174	1,191	1,218	1,233	1,236	1,243	1,259	1,277	1,286	0	0	0	0

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2

Run Date: 09/17/92

Run Time: 11:30 AM

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,400	3,457	3,514	3,572	3,631	3,691
DISTILLATE OIL	1,165	898	877	897	899	891	884	875	867	857	844	831
LPG	400	364	358	361	363	362	362	360	358	355	352	348
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,497	4,700	4,853	4,854	4,863	4,894	4,890	4,887	4,882	4,885	4,881
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,572	8,960	9,245	9,459	9,501	9,539	9,601	9,641	9,686	9,725	9,771	9,809
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,049	3,095	3,141	3,188	3,236	3,285
DISTILLATE OIL	561	518	509	521	526	526	523	522	523	521	520	522
LPG	70	65	63	65	64	64	64	64	64	63	63	63
COAL	88	94	88	94	94	94	94	93	93	93	92	93
NATURAL GAS	2,771	2,729	2,846	2,849	2,847	2,859	2,880	2,879	2,875	2,882	2,919	2,971
RESIDUAL OIL	228	226	223	220	214	210	207	203	198	195	193	192
TOTAL FUELS	6,472	6,494	6,653	6,703	6,731	6,771	6,817	6,856	6,893	6,941	7,023	7,124
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,416	7,643	7,719	7,774	7,702	7,725	7,810	7,893	8,034
HIGH SULFUR RESID	311	288	249	267	253	243	239	279	268	278	276	275
LOW SULFUR RESID	301	286	252	299	273	262	293	371	450	463	467	500
DISTILLATE	1,133	1,167	1,103	1,097	1,110	1,091	1,097	1,093	1,101	1,106	1,111	1,117
ELECTRICITY	3,135	3,212	3,195	3,231	3,267	3,304	3,342	3,406	3,472	3,539	3,611	3,689
COAL	1,652	1,655	1,620	1,631	1,650	1,658	1,678	1,710	1,737	1,780	1,831	1,899
TOTAL FUELS	13,471	13,653	13,794	13,940	14,196	14,278	14,423	14,561	14,753	14,976	15,189	15,515
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,898	2,904	2,942	3,058	3,162	3,355	3,497	3,691	4,003
HIGH SULFUR RESID	590	490	477	554	468	452	476	550	548	541	535	424
LOW SULFUR RESID	858	671	634	604	657	688	720	669	631	580	564	555
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	150
COAL	15,842	16,067	16,009	16,085	16,275	16,328	16,395	16,533	16,757	16,920	17,098	17,198
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,383
TOTAL FUELS	28,733	29,381	29,664	29,912	30,192	30,468	30,779	31,178	31,582	31,940	32,322	32,711
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,417	17,125	17,827	18,016	18,247	18,383	18,606	18,632	18,842	19,071	19,387	19,888
HIGH SULFUR RESID	901	778	726	822	721	695	715	829	816	819	811	699
LOW SULFUR RESID	1,387	1,184	1,109	1,122	1,145	1,161	1,219	1,243	1,279	1,238	1,224	1,246
DISTILLATE	2,988	2,640	2,556	2,588	2,613	2,595	2,599	2,593	2,603	2,613	2,622	2,619
COAL	17,640	17,878	17,775	17,870	18,079	18,141	18,227	18,396	18,647	18,852	19,080	19,248
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,237	10,399	10,462	10,585	10,601	10,690	10,703	10,794
TOTAL FUELS	49,308	49,276	49,986	50,541	51,042	51,374	51,827	52,278	52,787	53,283	53,827	54,494

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,749	3,812	3,875	3,934	4,002	4,064	4,130	4,195	4,263	4,333	0	0	0	0
DISTILLATE OIL	817	804	791	779	767	756	746	736	726	717	0	0	0	0
LPG	344	340	336	333	329	326	323	320	317	315	0	0	0	0
COAL	59	58	58	58	58	58	57	57	57	57	0	0	0	0
NATURAL GAS	4,885	4,897	4,909	4,929	4,933	4,937	4,946	4,964	4,981	5,009	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,854	9,911	9,968	10,032	10,089	10,141	10,201	10,272	10,344	10,431	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,332	3,382	3,433	3,477	3,533	3,581	3,633	3,683	3,736	3,793	0	0	0	0
DISTILLATE OIL	526	529	533	538	546	549	555	559	559	556	0	0	0	0
LPG	63	64	64	65	66	67	67	68	68	68	0	0	0	0
COAL	93	94	95	96	98	98	99	100	100	99	0	0	0	0
NATURAL GAS	3,039	3,109	3,187	3,269	3,341	3,391	3,453	3,515	3,560	3,591	0	0	0	0
RESIDUAL OIL	192	193	194	195	196	195	196	196	196	195	0	0	0	0
TOTAL FUELS	7,245	7,370	7,506	7,641	7,779	7,880	8,003	8,120	8,219	8,301	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	8,254	8,406	8,492	8,700	8,706	8,808	8,901	9,024	9,148	9,298	0	0	0	0
HIGH SULFUR RESID	222	208	207	205	206	205	204	202	200	193	0	0	0	0
LOW SULFUR RESID	458	424	432	411	427	428	432	429	404	355	0	0	0	0
DISTILLATE	1,135	1,146	1,150	1,167	1,164	1,170	1,175	1,186	1,199	1,215	0	0	0	0
ELECTRICITY	3,787	3,849	3,937	4,009	4,094	4,165	4,254	4,341	4,440	4,589	0	0	0	0
COAL	1,917	1,944	1,989	2,016	2,074	2,099	2,118	2,132	2,142	2,150	0	0	0	0
TOTAL FUELS	15,774	15,977	16,207	16,508	16,671	16,874	17,084	17,314	17,533	17,799	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,156	4,240	4,394	4,504	4,659	4,791	4,955	5,118	5,309	5,548	0	0	0	0
HIGH SULFUR RESID	359	348	343	341	344	343	344	346	351	357	0	0	0	0
LOW SULFUR RESID	615	614	612	619	646	662	684	716	742	742	0	0	0	0
DISTILLATE	153	156	160	163	167	170	174	178	182	186	0	0	0	0
COAL	17,539	17,880	18,239	18,567	18,905	19,216	19,560	19,892	20,254	20,729	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,355	10,335	10,316	10,296	10,279	10,261	10,245	10,228	10,213	10,210	0	0	0	0
TOTAL FUELS	33,177	33,573	34,063	34,489	34,999	35,443	35,961	36,479	37,051	37,773	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	20,334	20,652	20,981	21,401	21,639	21,927	22,255	22,621	22,997	23,447	0	0	0	0
HIGH SULFUR RESID	581	557	550	546	550	548	548	548	551	549	0	0	0	0
LOW SULFUR RESID	1,265	1,230	1,238	1,224	1,269	1,285	1,311	1,342	1,342	1,292	0	0	0	0
DISTILLATE	2,632	2,635	2,633	2,648	2,644	2,645	2,649	2,659	2,665	2,673	0	0	0	0
COAL	19,608	19,976	20,382	20,737	21,134	21,471	21,835	22,181	22,553	23,036	0	0	0	0
ALL OTHER FUELS	10,762	10,738	10,716	10,694	10,674	10,653	10,635	10,616	10,599	10,593	0	0	0	0
TOTAL FUELS	55,181	55,788	56,499	57,249	57,909	58,528	59,232	59,967	60,707	61,589	0	0	0	0

NPCSP25B: NPC SUPPLY CONFIDENCE POSITIVE CASE REVISED #2

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AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	1.76	1.73	1.57	1.55	1.69	1.88	2.11	2.34	2.41	2.52	2.66	2.75		
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.58	2.74	3.01	3.26	3.33	3.45	3.61	3.71		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.33	5.50	5.76	6.02	6.10	6.22	6.37	6.45		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.46	4.62	4.88	5.14	5.22	5.34	5.49	5.59		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.90	3.10	3.40	3.70	3.81	3.97	4.16	4.32		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.75	2.96	3.28	3.58	3.66	3.78	3.95	4.06		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.49	1.65	1.89	2.11	2.19	2.30	2.41	2.51		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.76	1.94	2.20	2.41	2.49	2.59	2.70	2.80		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.07	2.26	2.52	2.68	2.73	2.80	2.91	3.02		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.62	2.75	2.92	3.20	3.46	3.54	3.66	3.83	3.93		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	2.73	2.60	2.46	2.48	2.47	2.39	2.38	2.52	2.67	2.82	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.67	3.51	3.33	3.33	3.29	3.18	3.16	3.30	3.45	3.62	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.37	6.19	5.98	5.96	5.91	5.77	5.68	5.79	5.93	6.08	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.52	5.34	5.14	5.13	5.08	4.95	4.88	5.00	5.15	5.31	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.24	4.04	3.83	3.81	3.78	3.71	3.70	3.86	4.04	4.21	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.00	3.83	3.64	3.63	3.59	3.52	3.48	3.62	3.77	3.94	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.51	2.39	2.26	2.29	2.30	2.23	2.24	2.40	2.56	2.72	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.83	2.70	2.54	2.56	2.56	2.46	2.46	2.63	2.81	2.97	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.10	3.04	2.87	2.89	2.88	2.79	2.82	2.99	3.17	3.34	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	3.89	3.72	3.53	3.53	3.49	3.38	3.36	3.50	3.66	3.84	0.00	0.00	0.00	0.00

CASE 8

NPC Supply Confidence Negative Case Revised

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,811	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,340	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,105	17,347	75.6	82.9	1.03	1.26
1992	18.46	1.32	1.49	1.47	41.5	13,605	17,555	77.5	85.5	1.00	1.35
1993	18.60	1.53	1.70	1.64	47.8	13,655	17,742	77.0	88.5	0.99	1.57
1994	18.76	1.73	1.89	1.80	53.4	14,568	17,627	82.7	91.1	1.00	1.76
1995	19.01	1.94	2.11	2.00	59.2	15,232	17,702	86.1	93.4	1.03	1.92
1996	19.25	2.17	2.33	2.20	65.3	15,868	17,594	90.2	93.9	1.07	2.07
1997	19.56	2.22	2.39	2.25	65.9	16,072	17,722	90.7	94.3	1.07	2.12
1998	19.91	2.48	2.65	2.51	72.3	16,464	17,847	92.3	95.2	1.07	2.37
1999	20.51	2.64	2.81	2.68	74.8	17,604	17,952	98.1	95.4	1.07	2.52
2000	21.10	2.83	3.00	2.86	77.7	18,994	18,153	104.6	95.4	1.08	2.68
2001	21.75	2.97	3.14	3.00	79.1	19,209	18,620	103.2	95.7	1.08	2.81
2002	22.55	2.92	3.09	2.95	75.2	19,846	18,764	105.8	95.4	1.09	2.73
2003	23.45	3.04	3.21	3.05	75.1	20,068	19,081	105.2	95.4	1.10	2.82
2004	24.25	3.12	3.28	3.12	74.5	20,063	19,244	104.3	95.3	1.11	2.87
2005	25.14	3.22	3.38	3.21	74.2	20,478	19,380	105.7	95.2	1.11	2.96
2006	25.74	3.21	3.38	3.19	72.3	20,128	19,421	103.6	95.0	1.10	2.98
2007	26.25	3.29	3.46	3.27	72.7	19,231	19,368	99.3	95.0	1.09	3.08
2008	26.75	3.50	3.67	3.47	75.9	19,809	19,357	102.3	95.3	1.08	3.31
2009	27.35	3.80	3.97	3.75	80.6	20,265	19,244	105.3	95.3	1.08	3.60
2010	27.85	3.88	4.05	3.84	80.9	21,092	19,399	108.7	95.5	1.07	3.71
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
DEMAND												
RESIDENTIAL	4,900	4,497	4,700	4,852	4,853	4,859	4,889	4,891	4,891	4,889	4,874	4,864
COMMERCIAL *	2,771	2,729	2,846	2,849	2,846	2,855	2,875	2,880	2,878	2,887	2,910	2,955
INDUSTRIAL	6,939	7,046	7,376	7,408	7,641	7,676	7,755	7,726	7,766	7,778	7,764	7,830
BOILERS	2,791	2,831	2,983	2,921	3,008	3,074	3,121	3,121	3,122	3,121	3,118	3,119
NONBOILERS	4,148	4,215	4,393	4,487	4,633	4,602	4,635	4,606	4,644	4,658	4,646	4,712
ELECTRIC UTILITY	2,808	2,852	2,905	2,891	2,903	2,930	3,063	3,166	3,372	3,458	3,601	3,843
TOTAL END USE DEMAND	17,417	17,125	17,827	18,000	18,242	18,320	18,582	18,663	18,907	19,012	19,149	19,492
LEASE AND PLANT USE	885	1,060	1,093	1,107	1,116	1,106	1,109	1,099	1,105	1,110	1,115	1,127
TRANSMISSION FUEL	655	644	670	677	686	689	699	702	711	715	720	733
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547
TOTAL DISPOSITION	19,137	19,001	19,848	20,103	20,432	20,546	20,852	20,947	21,222	21,353	21,516	21,899
SUPPLY												
LOWER-48 PRODUCTION	17,651	17,341	17,938	18,063	18,250	18,130	18,204	18,090	18,196	18,344	18,463	18,694
PIPELINE IMPORTS	1,326	1,465	1,709	1,837	1,965	2,170	2,389	2,518	2,655	2,518	2,488	2,591
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	243	320	349	468	540	587
TOTAL GAS SUPPLY	19,130	18,997	19,844	20,098	20,427	20,535	20,837	20,928	21,201	21,330	21,490	21,871

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,856	4,850	4,854	4,852	4,853	4,852	4,856	4,861	4,866	4,877	0	0	0	0
COMMERCIAL *	3,013	3,066	3,137	3,200	3,267	3,311	3,368	3,414	3,444	3,456	0	0	0	0
INDUSTRIAL	7,989	8,094	8,207	8,240	8,272	8,348	8,400	8,435	8,402	8,523	0	0	0	0
BOILERS	3,228	3,310	3,387	3,419	3,444	3,504	3,542	3,545	3,467	3,542	0	0	0	0
NONBOILERS	4,761	4,784	4,820	4,822	4,828	4,844	4,858	4,890	4,935	4,981	0	0	0	0
ELECTRIC UTILITY	4,063	4,183	4,296	4,403	4,513	4,651	4,809	4,966	5,040	5,165	0	0	0	0
TOTAL END USE DEMAND	19,921	20,193	20,492	20,696	20,904	21,162	21,432	21,676	21,753	22,020	0	0	0	0
LEASE AND PLANT USE	1,156	1,162	1,181	1,190	1,197	1,197	1,192	1,188	1,178	1,184	0	0	0	0
TRANSMISSION FUEL	749	759	771	778	788	796	806	815	818	828	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,341	22,598	22,896	23,084	23,275	23,495	23,723	23,961	24,031	24,230	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,171	19,309	19,635	19,816	19,975	20,022	19,979	19,970	19,872	20,007	0	0	0	0
PIPELINE IMPORTS	2,583	2,751	2,743	2,753	2,786	2,920	3,076	3,222	3,306	3,373	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	556	524	509	507	507	545	660	761	844	841	0	0	0	0
TOTAL GAS SUPPLY	22,310	22,583	22,886	23,077	23,268	23,487	23,715	23,953	24,022	24,220	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

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ENERGY DEMAND FOR COMBUSTION USES

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
NATURAL GAS	17,417	17,125	17,827	18,000	18,242	18,320	18,582	18,663	18,907	19,012	19,149	19,492		
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,959	1,868	1,899	1,928	2,061	2,054	2,154	2,197	2,213		
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,613	2,594	2,597	2,599	2,606	2,615	2,611	2,603		
LPG (RES/COM SECTORS)	470	429	421	426	428	427	426	424	422	419	415	411		
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,082	18,144	18,234	18,396	18,639	18,860	19,094	19,258		
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,226		
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157		
PRIMARY ENERGY CONSUMPTION	49,308	49,276	49,986	50,541	51,043	51,357	51,803	52,305	52,807	53,332	53,754	54,360		
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,578	9,684	9,794	9,959	10,127	10,300	10,471	10,652		
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,912)	(30,194)	(30,473)	(30,788)	(31,181)	(31,582)	(31,942)	(32,300)	(32,670)		
END USE ENERGY DEMAND	29,515	29,107	29,692	30,102	30,427	30,568	30,809	31,082	31,351	31,690	31,925	32,341		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	19,921	20,193	20,492	20,696	20,904	21,162	21,432	21,676	21,752	22,020	0	0	0	0
RESIDUAL FUEL OIL	2,025	1,923	1,848	1,841	1,845	1,828	1,843	1,945	2,170	2,106	0	0	0	0
DISTILLATE FUEL OIL	2,610	2,607	2,604	2,591	2,583	2,577	2,571	2,568	2,567	2,578	0	0	0	0
LPG (RES/COM SECTORS)	408	404	401	396	393	389	385	383	381	380	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,618	20,018	20,439	20,853	21,217	21,610	22,015	22,370	22,768	23,256	0	0	0	0
HYDRO/RENEWABLES	3,249	3,281	3,313	3,346	3,379	3,414	3,450	3,486	3,522	3,571	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	54,938	55,481	56,100	56,676	57,225	57,831	58,498	59,178	59,862	60,562	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,835	11,021	11,214	11,406	11,598	11,807	12,031	12,234	12,429	12,643	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(33,081)	(33,511)	(33,977)	(34,449)	(34,918)	(35,445)	(36,011)	(36,532)	(37,035)	(37,597)	0	0	0	0
END USE ENERGY DEMAND	32,692	32,991	33,337	33,633	33,904	34,193	34,518	34,880	35,256	35,608	0	0	0	0

NPCSM25B: NPC SUPPLY CONFIDENCE NEGATIVE CASE REVISED #2									Run Date: 09/17/92			
									Run Time: 11:29 AM			
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,401	3,457	3,514	3,571	3,631	3,691
DISTILLATE OIL	1,165	898	877	898	899	892	885	876	867	858	844	831
LPG	400	364	358	361	363	363	362	360	358	356	352	348
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,497	4,700	4,852	4,853	4,859	4,889	4,891	4,891	4,889	4,874	4,864
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,572	8,960	9,245	9,459	9,500	9,537	9,597	9,645	9,689	9,734	9,759	9,793
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,050	3,095	3,141	3,187	3,236	3,286
DISTILLATE OIL	561	518	509	521	526	528	524	524	522	522	521	525
LPG	70	65	63	65	65	65	64	64	64	63	63	63
COAL	88	94	88	94	94	95	94	94	93	93	92	93
NATURAL GAS	2,771	2,729	2,846	2,849	2,846	2,855	2,875	2,880	2,878	2,887	2,910	2,955
RESIDUAL OIL	228	226	223	220	214	210	207	203	199	195	192	191
TOTAL FUELS	6,472	6,494	6,653	6,703	6,731	6,769	6,813	6,858	6,896	6,947	7,015	7,112
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,408	7,641	7,676	7,755	7,726	7,766	7,778	7,764	7,830
HIGH SULFUR RESID	311	288	249	270	254	252	238	274	254	305	323	351
LOW SULFUR RESID	301	286	252	304	275	283	291	368	438	489	512	572
DISTILLATE	1,133	1,167	1,103	1,096	1,109	1,087	1,094	1,096	1,105	1,106	1,100	1,098
ELECTRICITY	3,135	3,212	3,195	3,231	3,268	3,305	3,344	3,407	3,472	3,542	3,604	3,675
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,678	1,708	1,731	1,789	1,848	1,911
TOTAL FUELS	13,471	13,653	13,794	13,940	14,196	14,262	14,399	14,580	14,767	15,009	15,151	15,437
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,891	2,903	2,930	3,063	3,166	3,372	3,458	3,601	3,843
HIGH SULFUR RESID	590	490	477	569	470	490	472	549	542	556	559	486
LOW SULFUR RESID	858	671	634	596	656	663	720	667	621	609	611	613
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	150
COAL	15,842	16,067	16,009	16,085	16,277	16,330	16,402	16,535	16,755	16,919	17,094	17,196
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,383
TOTAL FUELS	28,733	29,381	29,664	29,912	30,194	30,473	30,788	31,181	31,582	31,942	32,300	32,670
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,417	17,125	17,827	18,000	18,242	18,320	18,582	18,663	18,907	19,012	19,149	19,492
HIGH SULFUR RESID	901	778	726	839	724	743	710	823	796	862	882	837
LOW SULFUR RESID	1,387	1,184	1,109	1,120	1,145	1,156	1,218	1,238	1,258	1,293	1,315	1,376
DISTILLATE	2,988	2,640	2,556	2,588	2,613	2,594	2,597	2,599	2,606	2,615	2,611	2,603
COAL	17,640	17,878	17,775	17,870	18,082	18,144	18,234	18,396	18,639	18,860	19,094	19,258
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,238	10,400	10,462	10,586	10,601	10,691	10,703	10,794
TOTAL FUELS	49,308	49,276	49,986	50,541	51,043	51,356	51,803	52,305	52,806	53,332	53,754	54,360

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,751	3,814	3,878	3,943	4,009	4,075	4,145	4,214	4,279	4,350	0	0	0	0
DISTILLATE OIL	818	804	790	776	763	750	738	728	720	712	0	0	0	0
LPG	344	340	335	331	327	322	318	315	313	312	0	0	0	0
COAL	59	58	58	58	57	57	57	57	56	56	0	0	0	0
NATURAL GAS	4,856	4,850	4,854	4,852	4,853	4,852	4,856	4,861	4,866	4,877	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,828	9,866	9,915	9,960	10,009	10,057	10,115	10,175	10,234	10,307	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,334	3,384	3,436	3,488	3,540	3,594	3,652	3,706	3,755	3,811	0	0	0	0
DISTILLATE OIL	531	534	539	542	547	548	551	555	560	562	0	0	0	0
LPG	64	65	65	66	66	66	67	67	68	68	0	0	0	0
COAL	94	94	95	96	97	97	98	99	99	99	0	0	0	0
NATURAL GAS	3,013	3,066	3,137	3,200	3,267	3,311	3,368	3,414	3,444	3,456	0	0	0	0
RESIDUAL OIL	191	191	191	192	192	192	192	192	191	190	0	0	0	0
TOTAL FUELS	7,226	7,335	7,463	7,583	7,710	7,809	7,927	8,034	8,118	8,186	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	7,989	8,094	8,207	8,240	8,272	8,348	8,400	8,435	8,402	8,523	0	0	0	0
HIGH SULFUR RESID	315	270	238	234	221	199	193	228	344	329	0	0	0	0
LOW SULFUR RESID	533	504	473	467	455	436	424	455	506	496	0	0	0	0
DISTILLATE	1,108	1,112	1,115	1,110	1,107	1,108	1,108	1,107	1,105	1,119	0	0	0	0
ELECTRICITY	3,751	3,823	3,901	3,975	4,049	4,138	4,234	4,313	4,394	4,483	0	0	0	0
COAL	1,942	1,987	2,027	2,065	2,082	2,099	2,118	2,133	2,152	2,166	0	0	0	0
TOTAL FUELS	15,638	15,790	15,959	16,090	16,186	16,328	16,476	16,671	16,903	17,115	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,063	4,183	4,296	4,403	4,513	4,651	4,809	4,966	5,040	5,165	0	0	0	0
HIGH SULFUR RESID	434	387	361	354	348	340	343	357	406	397	0	0	0	0
LOW SULFUR RESID	552	571	585	595	628	661	691	712	723	694	0	0	0	0
DISTILLATE	153	156	160	163	166	170	174	178	182	185	0	0	0	0
COAL	17,524	17,878	18,259	18,635	18,981	19,357	19,743	20,082	20,460	20,934	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,356	10,336	10,317	10,300	10,282	10,266	10,252	10,237	10,223	10,222	0	0	0	0
TOTAL FUELS	33,081	33,511	33,977	34,449	34,918	35,445	36,011	36,532	37,035	37,597	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	19,921	20,193	20,492	20,696	20,904	21,162	21,432	21,676	21,752	22,020	0	0	0	0
HIGH SULFUR RESID	748	658	598	588	570	539	536	585	750	726	0	0	0	0
LOW SULFUR RESID	1,277	1,266	1,249	1,253	1,276	1,289	1,307	1,360	1,420	1,380	0	0	0	0
DISTILLATE	2,610	2,607	2,604	2,591	2,583	2,577	2,571	2,568	2,567	2,578	0	0	0	0
COAL	19,618	20,018	20,439	20,853	21,217	21,610	22,015	22,370	22,768	23,256	0	0	0	0
ALL OTHER FUELS	10,764	10,741	10,718	10,696	10,675	10,655	10,637	10,620	10,605	10,602	0	0	0	0
TOTAL FUELS	54,938	55,481	56,100	56,676	57,224	57,831	58,498	59,178	59,861	60,562	0	0	0	0

NPCSM25B: NPC SUPPLY CONFIDENCE NEGATIVE CASE REVISED #2											Run Date: 09/17/92	
TABLE 2: LOWER 48 WELLS AND RESERVES											Run Time: 11:29 AM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,567	4,696	4,551	5,488	6,319	6,766	7,266	7,821	9,658	11,715
DEVELOPMENT WELLS	22,582	27,158	26,414	21,951	22,076	26,681	30,820	31,141	30,336	27,923	33,096	36,104
TOTAL GAS WELLS	9,472	10,333	9,899	7,632	7,781	8,618	10,102	10,927	11,915	12,054	12,572	14,190
TOTAL WELLS	28,326	33,314	31,981	26,647	26,627	32,170	37,139	37,907	37,602	35,744	42,754	47,819
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	936	1,686	1,538	1,427	1,320	1,239	1,157	1,103	1,227	1,280
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,012	1,876	1,733	1,678	1,583	1,548	1,497	1,418	1,584	1,637
HIGH PERMEABILITY (BCF)	9,905	12,223	7,432	7,874	8,729	9,182	9,716	10,098	10,544	10,734	11,095	12,103
LOW PERMEABILITY (BCF)	1,339	1,691	1,532	1,784	1,095	1,270	1,139	1,093	1,116	1,234	1,581	1,899
DEVONIAN SHALE (BCF)	384	504	397	324	336	435	526	616	740	861	935	877
COAL BED METHANE (BCF)	1,607	2,111	2,386	1,429	1,475	1,548	1,707	1,657	1,222	1,148	1,221	1,220
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	152	315	381	466	501	543	535	408
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	135	135	140	181	390	453	526	654	850
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,093	11,729	11,922	12,890	13,649	14,321	14,575	15,046	16,020	17,357
TOTAL OIL (MMB)	1,194	1,388	936	1,686	1,538	1,427	1,320	1,239	1,157	1,103	1,227	1,280
TOTAL GAS (BCF)	15,127	18,454	13,105	13,605	13,655	14,568	15,232	15,868	16,072	16,464	17,604	18,994
TOTAL NGL (MMB)	550	681	432	524	522	552	571	597	631	653	706	763
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,723	1,714	1,686	1,665	1,666	1,658	1,640	1,625	1,618
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,483	2,377	2,242	2,169	2,134	2,119	2,078	2,032	1,999
HIGH PERMEABILITY (BCF)	12,033	12,428	12,367	12,359	12,511	12,417	12,400	12,231	12,217	12,216	12,151	12,134
LOW PERMEABILITY (BCF)	1,664	1,673	1,700	1,852	1,836	1,773	1,758	1,689	1,626	1,631	1,670	1,762
DEVONIAN SHALE (BCF)	152	180	210	226	240	261	291	314	358	394	441	477
COAL BED METHANE (BCF)	103	178	285	422	549	684	797	907	1,020	1,085	1,135	1,162
ENHANCED RECOVERY GAS (BCF)	83	114	138	162	166	177	203	218	241	269	314	358
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	51	64	72	82	102	140	174	210	262
TOTAL NON-ASSOC GAS (BCF)	14,082	14,620	14,748	15,073	15,365	15,384	15,532	15,460	15,603	15,769	15,920	16,154
TOTAL OIL (MMB)	1,871	1,782	1,751	1,723	1,714	1,686	1,665	1,666	1,658	1,640	1,625	1,618
TOTAL GAS (BCF)	16,811	17,340	17,347	17,555	17,742	17,627	17,702	17,594	17,722	17,847	17,952	18,153
TOTAL NGL (MMB)	739	751	747	758	763	749	748	743	750	759	762	766
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,854	18,817	18,641	18,383	18,038	17,611	17,111	16,574	16,176	15,838
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,303	21,696	21,052	20,488	19,902	19,316	18,694	18,033	17,585	17,223
HIGH PERMEABILITY (BCF)	105,432	105,226	100,393	95,908	92,126	88,891	86,207	84,074	82,401	80,919	79,862	79,832
LOW PERMEABILITY (BCF)	22,837	22,856	22,710	22,641	21,900	21,397	20,778	20,182	19,672	19,275	19,186	19,324
DEVONIAN SHALE (BCF)	1,751	2,076	2,263	2,361	2,457	2,631	2,865	3,168	3,549	4,016	4,510	4,910
COAL BED METHANE (BCF)	2,798	4,731	6,833	7,840	8,766	9,630	10,540	11,290	11,492	11,554	11,640	11,698
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,317	1,455	1,632	1,881	2,140	2,414	2,635	2,685
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	619	691	760	858	1,146	1,459	1,812	2,255	2,844
TOTAL NON-ASSOC GAS (BCF)	134,288	136,576	134,045	130,701	127,258	124,764	122,880	121,741	120,713	119,990	120,090	121,292
TOTAL OIL (MMB)	20,063	19,670	18,854	18,817	18,641	18,383	18,038	17,611	17,111	16,574	16,176	15,838
TOTAL GAS (BCF)	159,329	160,442	156,348	152,397	148,310	145,252	142,782	141,057	139,407	138,023	137,675	138,516
TOTAL NGL (MMB)	7,500	7,430	7,115	6,881	6,640	6,443	6,266	6,120	6,001	5,895	5,839	5,835
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,059	1,072	1,081	1,071	1,074	1,064	1,070	1,075	1,080	1,092

NPCSM25B: NPC SUPPLY CONFIDENCE NEGATIVE CASE REVISED #2											Run Date: 09/17/92			
TABLE 2: LOWER 48 WELLS AND RESERVES											Run Time: 11:29 AM			
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
EXPLORATORY WELLS	13,542	16,213	19,514	21,765	22,639	22,995	23,711	25,177	24,967	24,267	0	0	0	0
DEVELOPMENT WELLS	37,240	38,042	39,075	37,827	37,856	35,054	34,579	37,983	37,390	36,666	0	0	0	0
TOTAL GAS WELLS	14,092	13,998	13,919	14,271	15,299	15,404	15,381	16,531	17,840	19,134	0	0	0	0
TOTAL WELLS	50,782	54,255	58,589	59,592	60,495	58,049	58,290	63,160	62,357	60,933	0	0	0	0
RESERVE ADDITIONS														
OIL (MMB) CONVENTIONAL	1,365	1,361	1,394	1,416	1,438	1,297	1,104	1,180	1,064	928	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,749	1,787	1,868	1,897	1,944	1,759	1,519	1,567	1,404	1,229	0	0	0	0
HIGH PERMEABILITY (BCF)	12,006	12,285	12,439	12,265	12,130	11,645	10,718	10,133	9,563	9,304	0	0	0	0
LOW PERMEABILITY (BCF)	2,000	2,123	2,057	1,918	1,893	1,741	1,648	1,781	1,851	1,966	0	0	0	0
DEVONIAN SHALE (BCF)	841	741	607	583	501	489	475	465	495	555	0	0	0	0
COAL BED METHANE (BCF)	1,180	1,210	1,107	1,102	1,344	1,465	1,491	1,767	2,182	2,579	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	424	449	490	495	496	421	247	224	130	45	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	1,008	1,252	1,500	1,803	2,168	2,608	3,132	3,872	4,639	5,414	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	17,460	18,059	18,199	18,166	18,534	18,368	17,712	18,242	18,861	19,863	0	0	0	0
TOTAL OIL (MMB)	1,365	1,361	1,394	1,416	1,438	1,297	1,104	1,180	1,064	928	0	0	0	0
TOTAL GAS (BCF)	19,209	19,846	20,068	20,063	20,478	20,128	19,231	19,809	20,265	21,092	0	0	0	0
TOTAL NGL (MMB)	773	792	800	786	778	734	685	680	649	631	0	0	0	0
PRODUCTION (W/ LEASE & PLANT GAS)														
OIL (MMB) CONVENTIONAL	1,617	1,622	1,631	1,640	1,652	1,654	1,638	1,616	1,592	1,550	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,982	1,971	1,978	1,990	2,004	2,012	1,991	1,973	1,932	1,877	0	0	0	0
HIGH PERMEABILITY (BCF)	12,415	12,433	12,531	12,534	12,508	12,379	12,229	12,021	11,693	11,449	0	0	0	0
LOW PERMEABILITY (BCF)	1,838	1,865	1,945	1,971	1,969	1,937	1,884	1,849	1,815	1,840	0	0	0	0
DEVONIAN SHALE (BCF)	508	519	517	508	504	491	477	478	482	506	0	0	0	0
COAL BED METHANE (BCF)	1,183	1,202	1,217	1,219	1,233	1,267	1,284	1,323	1,380	1,460	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	357	373	383	397	411	426	416	384	330	305	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	336	401	511	627	751	908	1,088	1,330	1,613	1,962	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	16,638	16,793	17,103	17,254	17,376	17,409	17,377	17,385	17,312	17,523	0	0	0	0
TOTAL OIL (MMB)	1,617	1,622	1,631	1,640	1,652	1,654	1,638	1,616	1,592	1,550	0	0	0	0
TOTAL GAS (BCF)	18,620	18,764	19,081	19,244	19,380	19,421	19,368	19,357	19,244	19,399	0	0	0	0
TOTAL NGL (MMB)	785	785	795	797	796	790	777	767	754	742	0	0	0	0
RESERVES														
OIL (MMB) CONVENTIONAL	15,586	15,325	15,088	14,863	14,649	14,292	13,759	13,323	12,795	12,173	0	0	0	0
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	16,990	16,806	16,696	16,603	16,543	16,290	15,818	15,413	14,885	14,238	0	0	0	0
HIGH PERMEABILITY (BCF)	79,423	79,275	79,183	78,914	78,536	77,802	76,291	74,403	72,274	70,129	0	0	0	0
LOW PERMEABILITY (BCF)	19,485	19,743	19,855	19,802	19,727	19,531	19,296	19,229	19,264	19,390	0	0	0	0
DEVONIAN SHALE (BCF)	5,244	5,465	5,555	5,631	5,628	5,626	5,624	5,611	5,625	5,674	0	0	0	0
COAL BED METHANE (BCF)	11,695	11,702	11,592	11,475	11,586	11,784	11,991	12,436	13,237	14,356	0	0	0	0
ENHANCED RECOVERY GAS (BCF)	2,752	2,828	2,936	3,034	3,119	3,114	2,944	2,784	2,584	2,324	0	0	0	0
ENHANCED RECOVERY TIGHT (BCF)	3,516	4,367	5,356	6,532	7,949	9,649	11,693	14,234	17,261	20,712	0	0	0	0
TOTAL NON-ASSOC GAS (BCF)	122,114	123,381	124,476	125,388	126,545	127,505	127,839	128,697	130,245	132,565	0	0	0	0
TOTAL OIL (MMB)	15,586	15,325	15,088	14,863	14,649	14,292	13,759	13,323	12,795	12,173	0	0	0	0
TOTAL GAS (BCF)	139,104	140,187	141,173	141,991	143,089	143,795	143,657	144,109	145,130	146,823	0	0	0	0
TOTAL NGL (MMB)	5,823	5,831	5,837	5,826	5,808	5,753	5,661	5,574	5,469	5,358	0	0	0	0
LEASE AND PLANT GAS (BCF)														
	1,119	1,125	1,144	1,153	1,159	1,159	1,154	1,151	1,141	1,147	0	0	0	0

NPCHRF3F: NPC HIGH REFERENCE CASE NO. 3 FINAL (#5)

Run Date: 08/16/92

Run Time: 02:04 PM

AVERAGE NATURAL GAS PRICES

(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	1.76	1.73	1.57	1.55	1.71	1.91	2.12	2.34	2.43	2.59	2.79	3.04		
AVERAGE CITYGATE	2.75	2.73	2.53	2.46	2.59	2.77	3.01	3.25	3.35	3.54	3.78	4.04		
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.35	5.53	5.76	6.02	6.12	6.32	6.55	6.81		
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.48	4.65	4.88	5.14	5.23	5.43	5.67	5.94		
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.92	3.13	3.41	3.70	3.85	4.08	4.41	4.68		
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.65	2.77	3.00	3.29	3.58	3.68	3.88	4.14	4.42		
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.33	1.51	1.69	1.90	2.11	2.23	2.38	2.56	2.79		
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.78	1.97	2.21	2.41	2.52	2.61	2.78	3.01		
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.09	2.29	2.53	2.68	2.74	2.82	2.99	3.22		
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.63	2.77	2.96	3.21	3.46	3.56	3.75	4.00	4.28		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	3.04	2.96	2.95	2.93	2.89	2.86	2.95	3.14	3.42	3.44	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	4.03	3.93	3.90	3.86	3.79	3.74	3.83	4.03	4.34	4.34	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.79	6.67	6.62	6.55	6.47	6.40	6.49	6.68	6.99	6.99	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.93	5.81	5.77	5.71	5.63	5.57	5.66	5.86	6.18	6.17	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.65	4.53	4.48	4.42	4.34	4.29	4.40	4.63	4.98	5.00	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.40	4.28	4.23	4.18	4.10	4.04	4.13	4.33	4.65	4.64	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.80	2.76	2.76	2.75	2.73	2.73	2.84	3.05	3.34	3.38	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	3.01	3.04	3.08	3.07	3.04	3.02	3.14	3.36	3.67	3.70	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.22	3.27	3.39	3.42	3.38	3.37	3.48	3.71	4.02	4.06	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	4.26	4.16	4.13	4.09	4.01	3.96	4.05	4.26	4.58	4.59	0.00	0.00	0.00	0.00

CASE 9

NPC Supply Technology Positive Case

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,811	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,340	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,211	17,345	76.2	82.8	1.02	1.27
1992	18.46	1.32	1.49	1.47	41.5	13,790	17,572	78.5	85.5	0.99	1.36
1993	18.60	1.52	1.68	1.62	47.3	13,897	17,745	78.3	88.4	0.98	1.58
1994	18.76	1.70	1.87	1.78	52.6	14,796	17,660	83.8	90.9	0.98	1.77
1995	19.01	1.90	2.06	1.96	57.9	15,353	17,747	86.5	93.0	1.00	1.95
1996	19.25	2.15	2.31	2.19	64.6	15,303	17,665	86.6	93.8	1.02	2.14
1997	19.56	2.24	2.41	2.28	66.6	15,966	17,766	89.9	94.4	1.01	2.26
1998	19.91	2.45	2.62	2.48	71.5	16,598	17,978	92.3	95.1	1.01	2.47
1999	20.51	2.56	2.73	2.59	72.4	18,222	18,046	101.0	95.3	1.01	2.58
2000	21.10	2.70	2.87	2.74	74.2	19,627	18,445	106.4	95.5	1.01	2.72
2001	21.75	2.68	2.84	2.72	71.4	20,522	18,811	109.1	95.1	1.00	2.73
2002	22.55	2.66	2.83	2.71	68.4	21,434	19,183	111.7	94.6	0.99	2.74
2003	23.45	2.54	2.71	2.59	62.9	22,756	19,507	116.7	93.6	0.98	2.64
2004	24.25	2.53	2.69	2.57	60.4	23,202	20,011	116.0	93.2	0.99	2.60
2005	25.14	2.45	2.62	2.48	56.6	22,885	20,252	113.0	92.3	0.98	2.55
2006	25.74	2.45	2.62	2.46	55.2	22,762	20,454	111.3	91.9	0.97	2.58
2007	26.25	2.51	2.68	2.50	55.4	21,738	20,580	105.6	91.8	0.95	2.70
2008	26.75	2.63	2.80	2.61	57.0	21,670	20,835	104.0	92.4	0.95	2.83
2009	27.35	2.96	3.13	2.92	62.8	22,280	21,119	105.5	93.6	0.94	3.22
2010	27.85	2.93	3.09	2.89	60.9	23,403	21,154	110.6	93.2	0.93	3.23
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCST25A: NPC SUPPLY TECHNOLOGY POSITIVE CASE REVISED #4

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LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
DEMAND														
RESIDENTIAL	4,900	4,497	4,700	4,853	4,854	4,862	4,895	4,899	4,896	4,889	4,880	4,875		
COMMERCIAL *	2,771	2,729	2,846	2,849	2,847	2,858	2,880	2,886	2,882	2,887	2,915	2,965		
INDUSTRIAL	6,939	7,046	7,376	7,415	7,643	7,701	7,784	7,761	7,775	7,836	7,837	7,985		
BOILERS	2,791	2,831	2,983	2,925	3,010	3,088	3,135	3,136	3,125	3,153	3,159	3,217		
NONBOILERS	4,148	4,215	4,393	4,490	4,634	4,613	4,649	4,625	4,650	4,683	4,679	4,768		
ELECTRIC UTILITY	2,808	2,852	2,905	2,898	2,904	2,936	3,061	3,164	3,363	3,504	3,666	3,968		
TOTAL END USE DEMAND	17,417	17,125	17,827	18,015	18,248	18,356	18,620	18,709	18,916	19,116	19,298	19,792		
LEASE AND PLANT USE	885	1,060	1,093	1,108	1,116	1,108	1,112	1,104	1,108	1,120	1,122	1,145		
TRANSMISSION FUEL	655	644	670	677	686	690	700	704	711	719	726	744		
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547		
TOTAL DISPOSITION	19,137	19,001	19,848	20,119	20,438	20,585	20,894	21,001	21,235	21,470	21,677	22,229		
SUPPLY														
LOWER-48 PRODUCTION	17,651	17,341	17,938	18,080	18,256	18,165	18,251	18,164	18,266	18,487	18,570	19,002		
PIPELINE IMPORTS	1,326	1,465	1,709	1,836	1,964	2,174	2,385	2,499	2,586	2,509	2,588	2,681		
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0		
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	243	320	362	451	494	519		
TOTAL GAS SUPPLY	19,130	18,997	19,843	20,114	20,432	20,574	20,879	20,982	21,214	21,447	21,652	22,202		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,873	4,882	4,882	4,903	4,914	4,927	4,929	4,942	4,962	4,975	0	0	0	0
COMMERCIAL *	3,028	3,094	3,164	3,247	3,325	3,382	3,438	3,495	3,542	3,558	0	0	0	0
INDUSTRIAL	8,167	8,293	8,388	8,581	8,605	8,748	8,822	8,950	9,078	9,152	0	0	0	0
BOILERS	3,330	3,408	3,481	3,601	3,630	3,716	3,763	3,842	3,908	3,958	0	0	0	0
NONBOILERS	4,837	4,885	4,907	4,980	4,976	5,033	5,058	5,108	5,171	5,193	0	0	0	0
ELECTRIC UTILITY	4,122	4,226	4,328	4,474	4,625	4,761	4,924	5,087	5,280	5,473	0	0	0	0
TOTAL END USE DEMAND	20,190	20,495	20,761	21,204	21,469	21,818	22,113	22,473	22,862	23,158	0	0	0	0
LEASE AND PLANT USE	1,166	1,188	1,207	1,239	1,254	1,265	1,272	1,286	1,303	1,303	0	0	0	0
TRANSMISSION FUEL	759	771	781	797	807	820	832	845	860	871	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,631	22,938	23,201	23,660	23,918	24,244	24,509	24,886	25,306	25,528	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,366	19,739	20,081	20,603	20,876	21,094	21,256	21,501	21,793	21,811	0	0	0	0
PIPELINE IMPORTS	2,742	2,722	2,747	2,746	2,757	2,839	2,889	2,994	3,112	3,327	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	503	462	365	304	277	303	356	383	392	382	0	0	0	0
TOTAL GAS SUPPLY	22,611	22,924	23,192	23,653	23,910	24,236	24,501	24,878	25,297	25,519	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

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ENERGY DEMAND FOR COMBUSTION USES
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
NATURAL GAS	17,417	17,125	17,827	18,015	18,248	18,356	18,620	18,709	18,916	19,116	19,298	19,792
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,944	1,865	1,881	1,923	2,058	2,061	2,053	2,093	1,986
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,613	2,595	2,601	2,603	2,608	2,615	2,616	2,615
LPG (RES/COM SECTORS)	470	429	421	426	428	427	426	424	422	418	414	411
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,080	18,142	18,226	18,385	18,636	18,848	19,086	19,250
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,226
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157
PRIMARY ENERGY CONSUMPTION	49,308	49,276	49,986	50,541	51,043	51,374	51,830	52,342	52,821	53,322	53,794	54,437
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,577	9,684	9,791	9,954	10,124	10,301	10,479	10,658
LESS ELEC UTIL ENERGY INPUT	(28,733)	(29,381)	(29,664)	(29,912)	(30,192)	(30,472)	(30,778)	(31,168)	(31,573)	(31,947)	(32,323)	(32,690)
END USE ENERGY DEMAND	29,515	29,107	29,692	30,102	30,428	30,585	30,843	31,128	31,372	31,676	31,950	32,404

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	20,190	20,495	20,761	21,204	21,469	21,818	22,113	22,473	22,862	23,158	0	0	0	0
RESIDUAL FUEL OIL	1,892	1,853	1,775	1,742	1,803	1,819	1,833	1,848	1,888	1,832	0	0	0	0
DISTILLATE FUEL OIL	2,626	2,629	2,620	2,628	2,624	2,632	2,633	2,640	2,651	2,648	0	0	0	0
LPG (RES/COM SECTORS)	407	404	400	396	393	391	388	385	383	380	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,612	19,995	20,388	20,780	21,175	21,513	21,889	22,255	22,630	23,133	0	0	0	0
HYDRO/RENEWABLES	3,249	3,279	3,312	3,344	3,378	3,409	3,444	3,479	3,515	3,563	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	55,081	55,711	56,260	57,048	57,745	58,434	59,103	59,832	60,630	61,365	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,853	11,036	11,223	11,426	11,633	11,815	12,027	12,236	12,461	12,722	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(33,134)	(33,554)	(34,000)	(34,506)	(35,014)	(35,460)	(35,992)	(36,532)	(37,113)	(37,798)	0	0	0	0
END USE ENERGY DEMAND	32,801	33,193	33,482	33,969	34,364	34,789	35,137	35,536	35,978	36,288	0	0	0	0

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										Run Time: 09:41 AM		
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,400	3,455	3,512	3,571	3,632	3,691
DISTILLATE OIL	1,165	898	877	897	899	892	885	876	867	857	843	831
LPG	400	364	358	361	363	363	362	360	358	355	351	348
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,497	4,700	4,853	4,854	4,862	4,895	4,899	4,896	4,889	4,880	4,875
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,572	8,960	9,245	9,459	9,501	9,539	9,602	9,651	9,693	9,731	9,765	9,803
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,049	3,093	3,140	3,188	3,237	3,285
DISTILLATE OIL	561	518	509	521	526	527	524	523	522	520	519	522
LPG	70	65	63	65	64	64	64	64	63	63	63	63
COAL	88	94	88	94	94	94	94	94	93	92	92	93
NATURAL GAS	2,771	2,729	2,846	2,849	2,847	2,858	2,880	2,886	2,882	2,887	2,915	2,965
RESIDUAL OIL	228	226	223	220	214	210	207	203	199	195	193	191
TOTAL FUELS	6,472	6,494	6,653	6,703	6,731	6,771	6,817	6,862	6,898	6,946	7,019	7,119
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,415	7,643	7,701	7,784	7,761	7,775	7,836	7,837	7,985
HIGH SULFUR RESID	311	288	249	267	253	249	237	276	257	275	290	289
LOW SULFUR RESID	301	286	252	299	273	274	286	364	437	463	490	513
DISTILLATE	1,133	1,167	1,103	1,097	1,110	1,090	1,098	1,100	1,107	1,109	1,106	1,113
ELECTRICITY	3,135	3,212	3,195	3,231	3,267	3,305	3,342	3,406	3,472	3,543	3,610	3,682
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,678	1,708	1,732	1,774	1,834	1,902
TOTAL FUELS	13,471	13,653	13,794	13,940	14,196	14,276	14,424	14,614	14,780	14,999	15,167	15,483
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,898	2,904	2,936	3,061	3,164	3,363	3,504	3,666	3,968
HIGH SULFUR RESID	590	490	477	555	468	474	472	548	544	543	542	445
LOW SULFUR RESID	858	671	634	603	657	674	721	667	623	578	579	548
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	150
COAL	15,842	16,067	16,009	16,085	16,275	16,329	16,394	16,524	16,752	16,921	17,101	17,197
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,383
TOTAL FUELS	28,733	29,381	29,664	29,912	30,192	30,472	30,778	31,168	31,573	31,947	32,323	32,690
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,417	17,125	17,827	18,015	18,248	18,356	18,620	18,709	18,916	19,116	19,298	19,792
HIGH SULFUR RESID	901	778	726	823	720	723	709	824	802	818	832	733
LOW SULFUR RESID	1,387	1,184	1,109	1,122	1,145	1,158	1,214	1,234	1,259	1,236	1,261	1,253
DISTILLATE	2,988	2,640	2,556	2,588	2,613	2,595	2,601	2,603	2,608	2,615	2,616	2,615
COAL	17,640	17,878	17,775	17,870	18,080	18,142	18,226	18,385	18,636	18,848	19,086	19,250
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,237	10,400	10,462	10,586	10,600	10,690	10,702	10,794
TOTAL FUELS	49,308	49,276	49,986	50,541	51,042	51,373	51,830	52,341	52,821	53,322	53,794	54,437

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

LOWER 48 ENERGY DEMAND

(Trillion Btus)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,750	3,811	3,876	3,939	4,006	4,067	4,134	4,201	4,269	4,340	0	0	0	0
DISTILLATE OIL	818	805	790	777	765	754	743	733	724	714	0	0	0	0
LPG	344	340	335	331	328	325	321	318	316	313	0	0	0	0
COAL	59	58	58	58	58	58	57	57	57	57	0	0	0	0
NATURAL GAS	4,873	4,882	4,882	4,903	4,914	4,927	4,929	4,942	4,962	4,975	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,843	9,897	9,941	10,008	10,070	10,130	10,185	10,250	10,327	10,399	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,333	3,381	3,434	3,484	3,538	3,584	3,638	3,690	3,744	3,802	0	0	0	0
DISTILLATE OIL	528	532	535	538	543	547	552	555	557	553	0	0	0	0
LPG	64	64	65	65	66	66	67	67	68	67	0	0	0	0
COAL	94	94	95	96	97	98	99	99	99	99	0	0	0	0
NATURAL GAS	3,028	3,094	3,164	3,247	3,325	3,382	3,438	3,495	3,542	3,558	0	0	0	0
RESIDUAL OIL	192	192	193	194	195	195	195	195	195	194	0	0	0	0
TOTAL FUELS	7,238	7,358	7,484	7,623	7,763	7,871	7,989	8,101	8,204	8,272	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	8,167	8,293	8,388	8,581	8,605	8,748	8,822	8,950	9,078	9,152	0	0	0	0
HIGH SULFUR RESID	242	230	204	199	201	201	198	196	197	193	0	0	0	0
LOW SULFUR RESID	489	470	430	392	415	416	408	388	393	348	0	0	0	0
DISTILLATE	1,127	1,136	1,136	1,150	1,150	1,161	1,164	1,174	1,189	1,195	0	0	0	0
ELECTRICITY	3,770	3,844	3,913	4,003	4,090	4,165	4,254	4,345	4,448	4,580	0	0	0	0
COAL	1,925	1,966	1,987	2,012	2,071	2,098	2,118	2,132	2,142	2,150	0	0	0	0
TOTAL FUELS	15,720	15,937	16,058	16,337	16,531	16,788	16,963	17,185	17,447	17,618	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,122	4,226	4,328	4,474	4,625	4,761	4,924	5,087	5,280	5,473	0	0	0	0
HIGH SULFUR RESID	374	357	341	339	344	344	346	349	352	356	0	0	0	0
LOW SULFUR RESID	596	604	608	619	649	664	687	720	751	742	0	0	0	0
DISTILLATE	153	156	160	163	167	170	174	178	182	187	0	0	0	0
COAL	17,535	17,877	18,248	18,614	18,950	19,260	19,616	19,967	20,332	20,827	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,355	10,334	10,316	10,298	10,281	10,262	10,246	10,231	10,216	10,214	0	0	0	0
TOTAL FUELS	33,134	33,554	34,000	34,506	35,014	35,460	35,992	36,532	37,113	37,798	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	20,190	20,495	20,761	21,204	21,469	21,818	22,113	22,473	22,862	23,158	0	0	0	0
HIGH SULFUR RESID	615	587	545	538	545	544	544	545	550	549	0	0	0	0
LOW SULFUR RESID	1,276	1,265	1,231	1,204	1,258	1,274	1,290	1,303	1,338	1,283	0	0	0	0
DISTILLATE	2,626	2,629	2,620	2,628	2,624	2,632	2,633	2,640	2,651	2,648	0	0	0	0
COAL	19,612	19,995	20,388	20,780	21,175	21,513	21,889	22,255	22,630	23,133	0	0	0	0
ALL OTHER FUELS	10,762	10,739	10,716	10,694	10,674	10,652	10,634	10,616	10,599	10,594	0	0	0	0
TOTAL FUELS	55,081	55,711	56,260	57,048	57,745	58,434	59,102	59,832	60,630	61,364	0	0	0	0

NPCST25A: NPC SUPPLY TECHNOLOGY POSITIVE CASE REVISED #4											Run Date: 10/07/92	
TABLE 2: LOWER 48 WELLS AND RESERVES											Run Time: 09:41 AM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,578	4,838	4,745	5,686	6,345	6,620	7,903	8,820	10,145	12,182
DEVELOPMENT WELLS	22,582	27,158	26,428	22,540	22,987	27,229	30,410	30,111	32,863	32,500	35,097	38,529
TOTAL GAS WELLS	9,472	10,333	9,905	7,648	7,621	8,583	9,656	9,916	10,578	11,432	12,221	12,810
TOTAL WELLS	28,326	33,314	32,005	27,378	27,732	32,915	36,754	36,732	40,766	41,321	45,242	50,711
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	937	1,709	1,603	1,468	1,352	1,307	1,295	1,273	1,413	1,496
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,014	1,916	1,835	1,737	1,632	1,621	1,677	1,665	1,823	1,927
HIGH PERMEABILITY (BCF)	9,905	12,223	7,503	7,958	8,787	9,519	10,183	10,003	10,769	11,130	11,785	12,759
LOW PERMEABILITY (BCF)	1,339	1,691	1,535	1,790	1,098	1,251	1,046	1,009	1,186	1,289	1,507	1,758
DEVONIAN SHALE (BCF)	384	504	401	329	345	460	540	620	744	906	995	963
COAL BED METHANE (BCF)	1,607	2,111	2,413	1,462	1,526	1,551	1,645	1,540	982	824	954	894
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	153	143	150	325	380	478	593	663
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	152	154	134	157	185	226	307	565	663
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,197	11,873	12,063	13,058	13,722	13,682	14,288	14,932	16,399	17,700
TOTAL OIL (MMB)	1,194	1,388	937	1,709	1,603	1,468	1,352	1,307	1,295	1,273	1,413	1,496
TOTAL GAS (BCF)	15,127	18,454	13,211	13,790	13,897	14,796	15,353	15,303	15,966	16,598	18,222	19,627
TOTAL NGL (MMB)	550	681	435	528	526	558	574	580	629	659	725	792
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,725	1,721	1,700	1,683	1,688	1,690	1,688	1,692	1,702
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,485	2,387	2,261	2,192	2,161	2,155	2,136	2,110	2,098
HIGH PERMEABILITY (BCF)	12,033	12,428	12,368	12,371	12,504	12,439	12,465	12,359	12,350	12,411	12,309	12,487
LOW PERMEABILITY (BCF)	1,664	1,673	1,697	1,851	1,828	1,766	1,746	1,667	1,612	1,643	1,673	1,740
DEVONIAN SHALE (BCF)	152	180	211	226	240	263	295	320	360	403	451	499
COAL BED METHANE (BCF)	103	178	286	424	553	691	803	909	1,013	1,062	1,096	1,099
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	165	165	164	159	174	206	259	321
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	52	67	75	82	89	101	118	148	200
TOTAL NON-ASSOC GAS (BCF)	14,082	14,620	14,747	15,087	15,357	15,399	15,555	15,503	15,610	15,842	15,936	16,347
TOTAL OIL (MMB)	1,871	1,782	1,751	1,725	1,721	1,700	1,683	1,688	1,690	1,688	1,692	1,702
TOTAL GAS (BCF)	16,811	17,340	17,345	17,572	17,745	17,660	17,747	17,665	17,766	17,978	18,046	18,445
TOTAL NGL (MMB)	739	751	747	758	762	750	748	744	750	761	761	774
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,855	18,839	18,721	18,490	18,160	17,778	17,384	16,968	16,689	16,483
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,736	21,183	20,660	20,100	19,560	19,082	18,611	18,324	18,153
HIGH PERMEABILITY (BCF)	105,432	105,226	100,463	96,050	92,333	89,413	87,131	84,775	83,194	81,913	81,389	81,661
LOW PERMEABILITY (BCF)	22,837	22,856	22,716	22,654	21,924	21,409	20,708	20,050	19,623	19,269	19,103	19,121
DEVONIAN SHALE (BCF)	1,751	2,076	2,266	2,369	2,474	2,671	2,916	3,216	3,601	4,105	4,648	5,113
COAL BED METHANE (BCF)	2,798	4,731	6,858	7,896	8,868	9,728	10,571	11,202	11,171	10,932	10,790	10,585
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,331	1,318	1,296	1,282	1,448	1,654	1,926	2,261	2,603
ENHANCED RECOVERY TIGHT (BCF)	506	535	537	637	724	784	859	955	1,080	1,269	1,685	2,148
TOTAL NON-ASSOC GAS (BCF)	134,288	136,576	134,150	130,937	127,642	125,301	123,467	121,646	120,324	119,414	119,876	121,230
TOTAL OIL (MMB)	20,063	19,670	18,855	18,839	18,721	18,490	18,160	17,778	17,384	16,968	16,689	16,483
TOTAL GAS (BCF)	159,329	160,442	156,455	152,673	148,825	145,961	143,567	141,206	139,406	138,025	138,201	139,382
TOTAL NGL (MMB)	7,500	7,430	7,119	6,888	6,652	6,460	6,286	6,122	6,002	5,900	5,864	5,882
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,058	1,073	1,081	1,073	1,077	1,069	1,073	1,085	1,087	1,109

NPCST25A: NPC SUPPLY TECHNOLOGY POSITIVE CASE REVISED #4											TABLE 2: LOWER 48 WELLS AND RESERVES				Run Date: 10/07/92 Run Time: 09:41 AM	
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030		
EXPLORATORY WELLS	14,249	16,888	20,853	23,192	24,208	24,865	26,474	28,375	28,933	27,142	0	0	0	0		
DEVELOPMENT WELLS	39,111	38,771	43,950	41,695	40,603	38,603	37,176	37,096	38,558	39,392	0	0	0	0		
TOTAL GAS WELLS	13,308	14,320	14,531	14,791	14,718	14,786	15,075	16,214	17,187	18,226	0	0	0	0		
TOTAL WELLS	53,360	55,659	64,802	64,887	64,811	63,468	63,649	65,471	67,491	66,534	0	0	0	0		
RESERVE ADDITIONS																
OIL (MMB) CONVENTIONAL	1,527	1,534	1,716	1,769	1,816	1,668	1,537	1,431	1,337	1,193	0	0	0	0		
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
ASSOCIATED GAS (BCF)	1,986	2,028	2,268	2,352	2,410	2,207	2,027	1,856	1,709	1,545	0	0	0	0		
HIGH PERMEABILITY (BCF)	13,281	14,004	14,805	14,875	14,337	14,017	12,709	12,034	11,798	11,693	0	0	0	0		
LOW PERMEABILITY (BCF)	1,970	2,122	2,414	2,465	2,348	2,210	2,304	2,331	2,421	2,567	0	0	0	0		
DEVONIAN SHALE (BCF)	928	896	709	647	548	513	487	460	467	495	0	0	0	0		
COAL BED METHANE (BCF)	853	883	882	858	930	1,172	1,253	1,405	1,646	1,953	0	0	0	0		
ENHANCED RECOVERY GAS (BCF)	706	536	471	473	475	399	225	201	105	21	0	0	0	0		
ENHANCED RECOVERY TIGHT (BCF)	799	966	1,207	1,532	1,838	2,244	2,732	3,383	4,134	5,129	0	0	0	0		
TOTAL NON-ASSOC GAS (BCF)	18,535	19,406	20,488	20,850	20,476	20,555	19,711	19,814	20,571	21,858	0	0	0	0		
TOTAL OIL (MMB)	1,527	1,534	1,716	1,769	1,816	1,668	1,537	1,431	1,337	1,193	0	0	0	0		
TOTAL GAS (BCF)	20,522	21,434	22,756	23,202	22,885	22,762	21,738	21,670	22,280	23,403	0	0	0	0		
TOTAL NGL (MMB)	839	869	916	914	887	848	781	745	747	745	0	0	0	0		
PRODUCTION (W/ LEASE & PLANT GAS)																
OIL (MMB) CONVENTIONAL	1,716	1,730	1,757	1,794	1,832	1,857	1,862	1,851	1,826	1,785	0	0	0	0		
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
ASSOCIATED GAS (BCF)	2,103	2,107	2,134	2,176	2,220	2,253	2,259	2,245	2,224	2,167	0	0	0	0		
HIGH PERMEABILITY (BCF)	12,689	12,889	13,061	13,310	13,373	13,436	13,426	13,475	13,453	13,184	0	0	0	0		
LOW PERMEABILITY (BCF)	1,782	1,846	1,899	1,998	2,040	2,031	2,012	2,024	2,085	2,117	0	0	0	0		
DEVONIAN SHALE (BCF)	527	545	544	540	535	524	518	517	507	507	0	0	0	0		
COAL BED METHANE (BCF)	1,093	1,089	1,081	1,077	1,060	1,063	1,082	1,115	1,139	1,194	0	0	0	0		
ENHANCED RECOVERY GAS (BCF)	365	388	407	426	421	408	382	351	344	302	0	0	0	0		
ENHANCED RECOVERY TIGHT (BCF)	253	319	382	483	602	739	901	1,107	1,368	1,684	0	0	0	0		
TOTAL NON-ASSOC GAS (BCF)	16,708	17,076	17,374	17,834	18,032	18,201	18,321	18,589	18,895	18,987	0	0	0	0		
TOTAL OIL (MMB)	1,716	1,730	1,757	1,794	1,832	1,857	1,862	1,851	1,826	1,785	0	0	0	0		
TOTAL GAS (BCF)	18,811	19,183	19,507	20,011	20,252	20,454	20,580	20,835	21,119	21,154	0	0	0	0		
TOTAL NGL (MMB)	787	800	808	822	826	826	822	824	825	814	0	0	0	0		
RESERVES																
OIL (MMB) CONVENTIONAL	16,294	16,098	16,057	16,032	16,016	15,827	15,503	15,083	14,595	14,002	0	0	0	0		
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
ASSOCIATED GAS (BCF)	18,036	17,957	18,091	18,267	18,457	18,410	18,179	17,789	17,274	16,653	0	0	0	0		
HIGH PERMEABILITY (BCF)	82,252	83,367	85,111	86,676	87,639	88,220	87,503	86,062	84,406	82,916	0	0	0	0		
LOW PERMEABILITY (BCF)	19,309	19,585	20,099	20,566	20,873	21,052	21,345	21,653	21,990	22,440	0	0	0	0		
DEVONIAN SHALE (BCF)	5,514	5,865	6,030	6,137	6,149	6,139	6,108	6,051	6,012	5,999	0	0	0	0		
COAL BED METHANE (BCF)	10,345	10,139	9,939	9,721	9,591	9,700	9,871	10,160	10,667	11,426	0	0	0	0		
ENHANCED RECOVERY GAS (BCF)	2,944	3,091	3,156	3,202	3,257	3,248	3,090	2,940	2,701	2,420	0	0	0	0		
ENHANCED RECOVERY TIGHT (BCF)	2,694	3,341	4,166	5,215	6,451	7,955	9,786	12,061	14,827	18,272	0	0	0	0		
TOTAL NON-ASSOC GAS (BCF)	123,057	125,388	128,501	131,516	133,960	136,314	137,703	138,927	140,603	143,474	0	0	0	0		
TOTAL OIL (MMB)	16,294	16,098	16,057	16,032	16,016	15,827	15,503	15,083	14,595	14,002	0	0	0	0		
TOTAL GAS (BCF)	141,093	143,344	146,592	149,783	152,417	154,724	155,882	156,716	157,877	160,126	0	0	0	0		
TOTAL NGL (MMB)	5,934	6,003	6,111	6,203	6,264	6,286	6,245	6,166	6,088	6,019	0	0	0	0		
LEASE AND PLANT GAS (BCF)																
	1,130	1,151	1,169	1,200	1,214	1,225	1,232	1,245	1,262	1,262	0	0	0	0		

NPCST25A: NPC SUPPLY TECHNOLOGY POSITIVE CASE REVISED #4

Run Date: 10/07/92

Run Time: 09:41 AM

AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
LDC GAS TARIFF PRICES												
AVERAGE AQUISITION	1.76	1.73	1.57	1.55	1.70	1.86	2.02	2.27	2.37	2.58	2.69	2.84
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.58	2.73	2.91	3.18	3.28	3.51	3.67	3.82
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.34	5.48	5.65	5.93	6.03	6.29	6.44	6.57
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.46	4.60	4.77	5.05	5.15	5.40	5.56	5.70
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.91	3.09	3.31	3.64	3.77	4.03	4.29	4.44
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.76	2.96	3.19	3.50	3.60	3.84	4.02	4.17
END USER CARRIAGE PRICES												
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.50	1.66	1.83	2.07	2.15	2.35	2.46	2.59
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.77	1.95	2.13	2.37	2.45	2.60	2.71	2.84
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.08	2.27	2.45	2.66	2.71	2.81	2.92	3.05
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.62	2.76	2.91	3.09	3.38	3.48	3.73	3.89	4.04

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	2.83	2.83	2.70	2.67	2.57	2.56	2.60	2.69	2.98	2.93	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.79	3.77	3.61	3.55	3.42	3.38	3.42	3.50	3.82	3.74	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.52	6.48	6.30	6.22	6.07	6.00	6.01	6.07	6.38	6.29	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.66	5.63	5.46	5.38	5.24	5.18	5.19	5.27	5.58	5.50	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.39	4.34	4.16	4.08	3.96	3.93	3.97	4.08	4.42	4.36	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.13	4.10	3.93	3.86	3.72	3.68	3.70	3.79	4.12	4.03	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.58	2.61	2.50	2.49	2.43	2.43	2.48	2.59	2.90	2.86	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.90	2.93	2.81	2.79	2.70	2.69	2.74	2.85	3.18	3.14	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.12	3.23	3.15	3.13	3.04	3.03	3.08	3.19	3.53	3.48	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	4.01	3.99	3.83	3.77	3.63	3.59	3.63	3.71	4.04	3.97	0.00	0.00	0.00	0.00

CASE 10

NPC Pipeline Incentive Rate Sensitivity

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)

Run Date: 08/30/92

Run Time: 02:36 PM

ENERGY OVERVIEW MODEL SUMMARY

Year	Crude Oil & Natural Gas Prices					Lower 48 Gas Supply				Drilling Costs	
	U.S. Crude Oil Price (RACC)	Texas/Gulf Spot Whd Gas Price	Henry Hub Gas Price (Delv'd to PPL)	Lower 48 Avg Wellhead Gas Price	Spot Whd Gas Price to RACC	Reserve Additions	Dry Gas Production	Reserve Add. Replacement of Production	Deliverability Utilization	Producer Drilling Cost Index	Producer E&D Incentive @ 1988 Costs *
	(\$90/bbl)	(\$90/MMBtu)	(\$90/MMBtu)	(\$90/MMBtu)	(Btu Percent)	(Bcf/year)	(Bcf/year)	(Percent)	(Percent)	1988=1.00	(\$90/MMBtu)
1989	18.70	1.58	1.77	1.71	48.9	15,127	16,814	90.0	81.4	1.02	1.55
1990	22.32	1.51	1.69	1.66	39.3	18,454	17,341	106.4	82.6	1.03	1.50
1991	18.38	1.27	1.45	1.49	40.1	13,088	17,345	75.5	82.9	1.04	1.25
1992	18.46	1.32	1.49	1.47	41.5	13,719	17,564	78.1	85.5	1.00	1.35
1993	18.60	1.53	1.70	1.64	47.7	13,791	17,746	77.7	88.5	0.99	1.57
1994	18.76	1.72	1.89	1.80	53.3	14,692	17,675	83.1	91.1	1.00	1.75
1995	19.01	1.99	2.15	2.05	60.6	15,054	17,796	84.6	93.6	1.03	1.97
1996	19.25	2.19	2.36	2.24	66.1	15,706	17,636	89.1	94.0	1.06	2.11
1997	19.56	2.33	2.50	2.37	69.2	15,946	17,835	89.4	94.7	1.07	2.23
1998	19.91	2.49	2.66	2.52	72.5	16,526	17,859	92.5	95.1	1.06	2.40
1999	20.51	2.66	2.82	2.69	75.1	17,843	17,957	99.4	95.4	1.06	2.57
2000	21.10	2.84	3.01	2.88	78.1	18,794	18,219	103.2	95.4	1.06	2.74
2001	21.75	2.86	3.03	2.90	76.2	20,224	18,622	108.6	95.5	1.06	2.76
2002	22.55	2.84	3.01	2.88	73.1	21,427	19,036	112.6	95.1	1.06	2.74
2003	23.45	2.78	2.95	2.82	68.8	22,167	19,449	114.0	94.6	1.06	2.68
2004	24.25	2.83	3.00	2.86	67.7	22,353	19,861	112.5	94.4	1.06	2.73
2005	25.14	2.71	2.88	2.73	62.6	22,624	20,048	112.9	93.4	1.05	2.64
2006	25.74	2.82	2.99	2.82	63.7	21,402	20,365	105.1	93.6	1.03	2.78
2007	26.25	2.90	3.07	2.88	64.2	20,759	20,395	101.8	93.7	1.03	2.86
2008	26.75	3.19	3.36	3.15	69.1	20,806	20,511	101.4	94.3	1.02	3.18
2009	27.35	3.44	3.60	3.38	72.9	21,670	20,503	105.7	94.7	1.02	3.43
2010	27.85	3.48	3.65	3.44	72.6	22,569	20,666	109.2	94.7	1.00	3.54
2015	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2020	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00
2030	0.00	0.00	0.00	0.00	0.0	0	0	0.0	0.0	0.00	0.00

* Lower-48 spot wellhead gas price adjusted to reflect change in drilling costs from 1988 levels.

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)

Run Date: 08/30/92

Run Time: 02:36 PM

LOWER 48 NATURAL GAS BALANCE
(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
DEMAND														
RESIDENTIAL	4,900	4,498	4,700	4,853	4,854	4,862	4,893	4,894	4,897	4,895	4,896	4,890		
COMMERCIAL *	2,772	2,730	2,846	2,849	2,846	2,858	2,879	2,883	2,885	2,895	2,932	2,982		
INDUSTRIAL	6,939	7,046	7,376	7,412	7,646	7,767	7,835	7,763	7,804	7,824	7,838	7,907		
BOILERS	2,792	2,831	2,983	2,923	3,011	3,078	3,123	3,107	3,114	3,118	3,129	3,133		
NONBOILERS	4,148	4,215	4,392	4,489	4,635	4,689	4,712	4,656	4,690	4,706	4,709	4,774		
ELECTRIC UTILITY	2,808	2,852	2,905	2,894	2,906	2,933	3,062	3,159	3,354	3,451	3,564	3,855		
TOTAL END USE DEMAND	17,419	17,126	17,827	18,007	18,252	18,420	18,669	18,698	18,940	19,065	19,230	19,634		
LEASE AND PLANT USE	886	1,060	1,093	1,108	1,116	1,109	1,115	1,102	1,112	1,112	1,116	1,131		
TRANSMISSION FUEL	655	644	670	677	666	693	702	703	712	717	723	738		
UAF + EXPORTS	179	172	258	319	388	431	463	484	500	516	531	547		
TOTAL DISPOSITION	19,138	19,002	19,848	20,111	20,443	20,652	20,948	20,986	21,264	21,410	21,601	22,050		
SUPPLY														
LOWER-48 PRODUCTION	17,652	17,342	17,938	18,071	18,250	18,180	18,302	18,133	18,332	18,360	18,472	18,791		
PIPELINE IMPORTS	1,327	1,465	1,709	1,836	1,975	2,226	2,388	2,505	2,528	2,542	2,556	2,650		
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0		
LNG + SNG + SUPPLEMENTALS	153	191	197	199	212	235	244	329	384	484	547	582		
TOTAL GAS SUPPLY	19,131	18,998	19,844	20,105	20,437	20,641	20,933	20,967	21,243	21,386	21,575	22,023		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
DEMAND														
RESIDENTIAL	4,886	4,895	4,903	4,922	4,928	4,946	4,948	4,966	4,979	5,003	0	0	0	0
COMMERCIAL *	3,046	3,113	3,191	3,274	3,348	3,410	3,470	3,533	3,574	3,599	0	0	0	0
INDUSTRIAL	8,076	8,272	8,406	8,516	8,564	8,755	8,806	8,891	8,920	9,004	0	0	0	0
BOILERS	3,249	3,374	3,469	3,542	3,577	3,679	3,720	3,763	3,775	3,826	0	0	0	0
NONBOILERS	4,827	4,898	4,937	4,973	4,987	5,076	5,087	5,127	5,145	5,178	0	0	0	0
ELECTRIC UTILITY	4,050	4,172	4,285	4,413	4,562	4,708	4,867	5,024	5,192	5,323	0	0	0	0
TOTAL END USE DEMAND	20,058	20,451	20,784	21,125	21,403	21,820	22,090	22,413	22,665	22,928	0	0	0	0
LEASE AND PLANT USE	1,154	1,178	1,203	1,228	1,238	1,256	1,255	1,260	1,258	1,265	0	0	0	0
TRANSMISSION FUEL	754	769	782	794	805	820	831	843	852	862	0	0	0	0
UAF + EXPORTS	516	484	452	420	388	341	293	282	282	197	0	0	0	0
TOTAL DISPOSITION	22,482	22,882	23,221	23,567	23,834	24,236	24,469	24,798	25,057	25,252	0	0	0	0
SUPPLY														
LOWER-48 PRODUCTION	19,157	19,584	20,009	20,458	20,675	20,997	21,024	21,145	21,136	21,292	0	0	0	0
PIPELINE IMPORTS	2,759	2,772	2,753	2,693	2,761	2,839	3,030	3,158	3,385	3,430	0	0	0	0
OTHER SUPPLY	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LNG + SNG + SUPPLEMENTALS	538	508	445	410	390	387	394	469	508	504	0	0	0	0
TOTAL GAS SUPPLY	22,455	22,864	23,207	23,559	23,826	24,223	24,448	24,771	25,029	25,225	0	0	0	0

* INCLUDES NATURAL GAS VEHICLES

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)

Run Date: 08/30/92

Run Time: 02:36 PM

ENERGY DEMAND FOR COMBUSTION USES

(Trillion Btus)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000		
NATURAL GAS	17,419	17,126	17,827	18,007	18,252	18,420	18,669	18,698	18,940	19,065	19,230	19,634		
RESIDUAL FUEL OIL	2,287	1,961	1,835	1,952	1,860	1,890	1,923	2,065	2,065	2,124	2,211	2,173		
DISTILLATE FUEL OIL	2,988	2,640	2,556	2,588	2,613	2,623	2,624	2,618	2,623	2,628	2,631	2,621		
LPG (RES/COM SECTORS)	470	429	420	426	428	427	426	424	422	419	416	412		
COAL (EXCLUDES COKING COAL)	17,640	17,878	17,775	17,870	18,081	18,144	18,230	18,392	18,641	18,856	19,079	19,236		
HYDRO/RENEWABLES	2,908	3,085	3,030	3,085	3,133	3,158	3,159	3,200	3,207	3,212	3,218	3,225		
NUCLEAR POWER	5,597	6,159	6,543	6,614	6,677	6,815	6,877	6,962	6,972	7,060	7,070	7,157		
PRIMARY ENERGY CONSUMPTION	49,308	49,277	49,986	50,541	51,042	51,477	51,908	52,358	52,870	53,364	53,854	54,458		
PLUS ELECTRICITY CONSUMED	8,941	9,212	9,371	9,473	9,578	9,685	9,793	9,957	10,124	10,296	10,463	10,640		
LESS ELEC UTIL ENERGY INPUT	(19,793)	(20,169)	(20,294)	(20,439)	(20,616)	(20,790)	(20,991)	(21,217)	(21,448)	(21,633)	(21,815)	(22,000)		
END USE ENERGY DEMAND	38,456	38,320	39,063	39,575	40,005	40,372	40,710	41,097	41,545	42,026	42,502	43,098		
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
NATURAL GAS	20,058	20,451	20,784	21,125	21,403	21,820	22,090	22,413	22,665	22,928	0	0	0	0
RESIDUAL FUEL OIL	1,995	1,872	1,776	1,757	1,782	1,797	1,785	1,841	1,903	1,890	0	0	0	0
DISTILLATE FUEL OIL	2,627	2,635	2,638	2,639	2,636	2,647	2,647	2,650	2,646	2,649	0	0	0	0
LPG (RES/COM SECTORS)	409	406	402	399	395	394	390	389	387	385	0	0	0	0
COAL (EXCLUDES COKING COAL)	19,593	19,967	20,353	20,763	21,107	21,443	21,803	22,171	22,519	22,924	0	0	0	0
HYDRO/RENEWABLES	3,245	3,273	3,303	3,334	3,366	3,397	3,429	3,461	3,494	3,531	0	0	0	0
NUCLEAR POWER	7,106	7,055	7,004	6,954	6,903	6,852	6,802	6,752	6,702	6,652	0	0	0	0
PRIMARY ENERGY CONSUMPTION	55,034	55,661	56,259	56,969	57,592	58,350	58,947	59,677	60,315	60,958	0	0	0	0
PLUS ELECTRICITY CONSUMED	10,820	10,997	11,182	11,374	11,569	11,756	11,957	12,163	12,366	12,569	0	0	0	0
LESS ELEC UTIL ENERGY INPUT	(22,221)	(22,451)	(22,709)	(22,993)	(23,275)	(23,551)	(23,855)	(24,178)	(24,498)	(24,821)	0	0	0	0
END USE ENERGY DEMAND	43,633	44,207	44,732	45,350	45,886	46,555	47,049	47,662	48,183	48,707	0	0	0	0

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)												Run Date: 08/30/92
Run Time: 02:36 PM												
LOWER 48 ENERGY DEMAND												
(Trillion Btus)												
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
RESIDENTIAL END USES												
ELECTRICITY	3,051	3,139	3,252	3,288	3,325	3,362	3,401	3,456	3,513	3,569	3,626	3,685
DISTILLATE OIL	1,165	898	877	897	899	892	885	876	867	858	845	832
LPG	400	364	358	361	363	363	362	360	358	356	353	349
COAL	58	62	58	60	60	60	60	60	60	60	59	59
NATURAL GAS	4,900	4,498	4,700	4,853	4,854	4,862	4,893	4,894	4,897	4,895	4,896	4,890
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,573	8,961	9,245	9,459	9,500	9,539	9,600	9,646	9,695	9,737	9,780	9,815
COMMERCIAL END USES												
ELECTRICITY	2,755	2,861	2,924	2,955	2,986	3,017	3,049	3,095	3,140	3,186	3,232	3,278
DISTILLATE OIL	561	518	509	521	526	527	524	523	522	522	522	525
LPG	70	65	63	65	64	65	64	64	64	63	63	64
COAL	88	94	88	94	94	95	94	94	93	93	93	93
NATURAL GAS	2,772	2,730	2,846	2,849	2,846	2,858	2,879	2,883	2,885	2,895	2,932	2,982
RESIDUAL OIL	228	226	223	220	214	210	207	203	199	195	193	192
TOTAL FUELS	6,472	6,494	6,653	6,703	6,731	6,772	6,817	6,861	6,902	6,954	7,034	7,134
INDUSTRIAL END USES *												
NATURAL GAS	6,939	7,046	7,376	7,412	7,646	7,767	7,835	7,763	7,804	7,824	7,838	7,907
HIGH SULFUR RESID	311	288	249	269	252	250	236	275	258	298	318	344
LOW SULFUR RESID	301	286	252	302	271	279	288	366	436	471	501	556
DISTILLATE	1,133	1,167	1,103	1,097	1,109	1,117	1,122	1,116	1,121	1,119	1,117	1,114
ELECTRICITY	3,135	3,212	3,195	3,231	3,268	3,305	3,343	3,406	3,471	3,540	3,605	3,677
COAL	1,652	1,655	1,620	1,631	1,650	1,659	1,678	1,708	1,734	1,787	1,846	1,911
TOTAL FUELS	13,471	13,653	13,794	13,940	14,195	14,376	14,501	14,634	14,824	15,038	15,225	15,509
ELECTRIC UTILITY ENERGY INPUT												
NATURAL GAS	2,808	2,852	2,905	2,894	2,906	2,933	3,062	3,159	3,354	3,451	3,564	3,855
HIGH SULFUR RESID	590	490	477	563	464	482	471	552	548	558	567	491
LOW SULFUR RESID	858	671	634	600	659	669	721	669	625	603	632	591
DISTILLATE	130	57	67	73	79	87	95	103	112	129	147	149
COAL	15,842	16,067	16,009	16,085	16,276	16,331	16,398	16,530	16,755	16,917	17,081	17,173
NUCLEAR/HYDRO/OTHER	8,505	9,244	9,573	9,699	9,810	9,973	10,036	10,162	10,179	10,272	10,288	10,382
TOTAL FUELS	28,733	29,381	29,664	29,912	30,193	30,474	30,784	31,174	31,572	31,929	32,278	32,641
PRIMARY ENERGY CONSUMPTION												
NATURAL GAS	17,419	17,126	17,827	18,007	18,252	18,420	18,669	18,698	18,940	19,065	19,230	19,634
HIGH SULFUR RESID	901	778	726	831	716	732	707	827	806	855	885	835
LOW SULFUR RESID	1,386	1,183	1,109	1,121	1,144	1,158	1,216	1,238	1,259	1,269	1,326	1,339
DISTILLATE	2,988	2,640	2,556	2,588	2,613	2,623	2,624	2,618	2,623	2,628	2,631	2,621
COAL	17,640	17,878	17,775	17,870	18,081	18,144	18,230	18,392	18,641	18,856	19,079	19,236
ALL OTHER FUELS	8,975	9,672	9,993	10,125	10,237	10,400	10,462	10,585	10,601	10,691	10,703	10,794
TOTAL FUELS	49,308	49,277	49,986	50,541	51,042	51,477	51,908	52,358	52,870	53,363	53,854	54,458

* EXCLUDES COAL AND OIL FEEDSTOCKS, LPG/STILL GAS, AND MISCELLANEOUS OIL FUELS.

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)											Run Date: 08/30/92			
LOWER 48 ENERGY DEMAND											Run Time: 02:36 PM			
(Trillion Btus)														
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
RESIDENTIAL END USES														
ELECTRICITY	3,743	3,800	3,860	3,921	3,984	4,043	4,105	4,168	4,231	4,293	0	0	0	0
DISTILLATE OIL	819	807	792	779	767	757	745	736	726	719	0	0	0	0
LPG	345	342	337	333	329	327	323	321	318	317	0	0	0	0
COAL	59	59	58	58	58	58	57	57	57	57	0	0	0	0
NATURAL GAS	4,886	4,895	4,903	4,922	4,928	4,946	4,948	4,966	4,979	5,003	0	0	0	0
RESIDUAL OIL	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL FUELS	9,852	9,902	9,951	10,014	10,065	10,130	10,178	10,247	10,312	10,389	0	0	0	0
COMMERCIAL END USES														
ELECTRICITY	3,324	3,369	3,416	3,464	3,513	3,558	3,606	3,655	3,703	3,750	0	0	0	0
DISTILLATE OIL	531	536	539	542	547	552	556	561	564	564	0	0	0	0
LPG	64	65	65	66	66	67	67	68	68	69	0	0	0	0
COAL	94	95	96	97	98	99	99	100	100	100	0	0	0	0
NATURAL GAS	3,046	3,113	3,191	3,274	3,348	3,410	3,470	3,533	3,574	3,599	0	0	0	0
RESIDUAL OIL	192	193	194	195	195	196	196	196	196	195	0	0	0	0
TOTAL FUELS	7,252	7,370	7,500	7,636	7,768	7,881	7,994	8,113	8,205	8,277	0	0	0	0
INDUSTRIAL END USES *														
NATURAL GAS	8,076	8,272	8,406	8,516	8,564	8,755	8,806	8,891	8,920	9,004	0	0	0	0
HIGH SULFUR RESID	301	248	206	203	202	203	195	201	213	211	0	0	0	0
LOW SULFUR RESID	513	472	428	417	411	408	382	399	416	398	0	0	0	0
DISTILLATE	1,124	1,137	1,148	1,154	1,156	1,169	1,173	1,177	1,175	1,180	0	0	0	0
ELECTRICITY	3,753	3,828	3,906	3,989	4,072	4,155	4,246	4,340	4,433	4,526	0	0	0	0
COAL	1,941	1,981	2,006	2,046	2,079	2,099	2,117	2,132	2,143	2,153	0	0	0	0
TOTAL FUELS	15,708	15,938	16,099	16,325	16,484	16,788	16,920	17,139	17,299	17,472	0	0	0	0
ELECTRIC UTILITY ENERGY INPUT														
NATURAL GAS	4,050	4,172	4,285	4,413	4,562	4,708	4,867	5,024	5,192	5,323	0	0	0	0
HIGH SULFUR RESID	429	375	341	335	341	341	344	345	351	351	0	0	0	0
LOW SULFUR RESID	560	585	608	608	633	650	669	700	727	735	0	0	0	0
DISTILLATE	152	156	159	163	166	170	173	177	181	185	0	0	0	0
COAL	17,498	17,833	18,192	18,562	18,872	19,188	19,529	19,882	20,218	20,614	0	0	0	0
NUCLEAR/HYDRO/OTHER	10,352	10,329	10,307	10,288	10,269	10,249	10,231	10,213	10,196	10,183	0	0	0	0
TOTAL FUELS	33,041	33,448	33,891	34,367	34,843	35,306	35,813	36,340	36,865	37,390	0	0	0	0
PRIMARY ENERGY CONSUMPTION														
NATURAL GAS	20,058	20,451	20,784	21,125	21,403	21,820	22,090	22,413	22,665	22,928	0	0	0	0
HIGH SULFUR RESID	730	623	547	538	543	544	539	546	564	562	0	0	0	0
LOW SULFUR RESID	1,265	1,249	1,229	1,219	1,239	1,253	1,246	1,295	1,339	1,328	0	0	0	0
DISTILLATE	2,627	2,635	2,638	2,639	2,636	2,647	2,647	2,650	2,646	2,649	0	0	0	0
COAL	19,593	19,967	20,353	20,763	21,107	21,443	21,803	22,171	22,519	22,924	0	0	0	0
ALL OTHER FUELS	10,761	10,735	10,709	10,687	10,665	10,643	10,621	10,602	10,582	10,568	0	0	0	0
TOTAL FUELS	55,033	55,661	56,259	56,969	57,591	58,350	58,947	59,677	60,314	60,958	0	0	0	0

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)											Run Date: 08/30/92	
TABLE 2: LOWER 48 WELLS AND RESERVES											Run Time: 02:36 PM	
	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
EXPLORATORY WELLS	5,744	6,156	5,536	4,703	4,493	5,503	6,289	6,685	7,149	8,077	9,617	11,414
DEVELOPMENT WELLS	22,582	27,158	26,372	21,929	21,014	26,744	30,755	31,014	29,948	30,092	32,964	35,601
TOTAL GAS WELLS	9,472	10,333	9,829	7,640	7,793	8,543	9,757	10,483	11,319	11,512	12,303	12,607
TOTAL WELLS	28,326	33,314	31,907	26,632	25,506	32,247	37,045	37,699	37,097	38,169	42,580	47,015
RESERVE ADDITIONS												
OIL (MMB) CONVENTIONAL	1,194	1,388	938	1,690	1,502	1,446	1,354	1,284	1,200	1,195	1,285	1,416
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	1,325	1,545	1,015	1,879	1,697	1,704	1,623	1,606	1,558	1,553	1,661	1,818
HIGH PERMEABILITY (BCF)	9,905	12,223	7,433	7,956	8,861	9,287	9,682	10,216	10,620	10,867	11,552	12,115
LOW PERMEABILITY (BCF)	1,339	1,691	1,497	1,793	1,103	1,278	1,075	1,037	1,143	1,187	1,473	1,735
DEVONIAN SHALE (BCF)	384	504	399	326	340	448	528	620	746	879	971	920
COAL BED METHANE (BCF)	1,607	2,111	2,400	1,446	1,501	1,521	1,621	1,592	1,125	990	1,043	1,037
ENHANCED RECOVERY GAS (BCF)	443	303	296	182	152	315	367	427	501	543	554	438
ENHANCED RECOVERY TIGHT (BCF)	123	77	49	136	137	140	157	208	255	508	589	732
TOTAL NON-ASSOC GAS (BCF)	13,801	16,909	12,073	11,839	12,094	12,988	13,430	14,100	14,389	14,973	16,182	16,976
TOTAL OIL (MMB)	1,194	1,388	938	1,690	1,502	1,446	1,354	1,284	1,200	1,195	1,285	1,416
TOTAL GAS (BCF)	15,127	18,454	13,088	13,719	13,791	14,692	15,054	15,706	15,946	16,526	17,843	18,794
TOTAL NGL (MMB)	550	681	429	527	520	551	560	592	624	646	706	752
PRODUCTION (W/ LEASE & PLANT GAS)												
OIL (MMB) CONVENTIONAL	1,871	1,782	1,751	1,723	1,712	1,683	1,666	1,672	1,669	1,658	1,652	1,653
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	2,730	2,720	2,598	2,483	2,376	2,240	2,170	2,141	2,131	2,100	2,062	2,041
HIGH PERMEABILITY (BCF)	12,035	12,429	12,370	12,369	12,515	12,464	12,483	12,293	12,365	12,246	12,181	12,263
LOW PERMEABILITY (BCF)	1,665	1,673	1,696	1,848	1,834	1,772	1,768	1,684	1,628	1,639	1,666	1,725
DEVONIAN SHALE (BCF)	152	180	211	226	240	263	294	314	360	399	446	490
COAL BED METHANE (BCF)	103	178	285	423	551	687	797	904	1,012	1,068	1,109	1,123
ENHANCED RECOVERY GAS (BCF)	83	114	137	162	166	177	203	213	235	273	318	352
ENHANCED RECOVERY TIGHT (BCF)	47	48	47	51	64	72	81	88	105	134	176	225
TOTAL NON-ASSOC GAS (BCF)	14,085	14,621	14,747	15,080	15,371	15,435	15,626	15,495	15,704	15,759	15,895	16,178
TOTAL OIL (MMB)	1,871	1,782	1,751	1,723	1,712	1,683	1,666	1,672	1,669	1,658	1,652	1,653
TOTAL GAS (BCF)	16,814	17,341	17,345	17,564	17,746	17,675	17,796	17,636	17,835	17,859	17,957	18,219
TOTAL NGL (MMB)	739	751	747	758	763	750	749	743	752	755	756	763
RESERVES												
OIL (MMB) CONVENTIONAL	20,063	19,670	18,857	18,823	18,614	18,377	18,065	17,677	17,208	16,745	16,379	16,142
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0
ASSOCIATED GAS (BCF)	25,041	23,866	22,305	21,701	21,023	20,487	19,940	19,405	18,833	18,285	17,884	17,661
HIGH PERMEABILITY (BCF)	105,428	105,222	100,387	95,974	92,320	89,143	86,342	84,265	82,519	81,140	80,512	80,363
LOW PERMEABILITY (BCF)	22,837	22,855	22,677	22,622	21,890	21,397	20,704	20,056	19,572	19,120	18,927	18,937
DEVONIAN SHALE (BCF)	1,751	2,076	2,264	2,365	2,465	2,650	2,884	3,190	3,576	4,056	4,581	5,011
COAL BED METHANE (BCF)	2,798	4,731	6,845	7,868	8,818	9,652	10,476	11,164	11,277	11,198	11,132	11,046
ENHANCED RECOVERY GAS (BCF)	963	1,152	1,311	1,330	1,317	1,454	1,618	1,832	2,097	2,367	2,604	2,690
ENHANCED RECOVERY TIGHT (BCF)	506	535	536	621	694	762	838	957	1,108	1,482	1,895	2,402
TOTAL NON-ASSOC GAS (BCF)	134,283	136,571	134,021	130,780	127,503	125,056	122,860	121,464	120,149	119,363	119,650	120,448
TOTAL OIL (MMB)	20,063	19,670	18,857	18,823	18,614	18,377	18,065	17,677	17,208	16,745	16,379	16,142
TOTAL GAS (BCF)	159,324	160,437	156,326	152,481	148,526	145,543	142,800	140,870	138,981	137,648	137,534	138,108
TOTAL NGL (MMB)	7,500	7,430	7,113	6,882	6,639	6,440	6,251	6,100	5,972	5,863	5,813	5,802
LEASE AND PLANT GAS (BCF)												
	857	1,026	1,058	1,073	1,081	1,074	1,079	1,067	1,077	1,077	1,081	1,095

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)											TABLE 2: LOWER 48 WELLS AND RESERVES					Run Date: 08/30/92 Run Time: 02:36 PM	
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030			
EXPLORATORY WELLS	13,747	16,725	19,814	21,886	22,595	23,448	23,983	24,879	27,098	26,874	0	0	0	0			
DEVELOPMENT WELLS	37,883	40,468	40,193	37,848	37,866	39,548	35,808	35,883	38,630	40,857	0	0	0	0			
TOTAL GAS WELLS	14,123	14,167	14,407	14,446	14,547	14,245	15,369	16,027	17,273	18,624	0	0	0	0			
TOTAL WELLS	51,630	57,193	60,007	59,734	60,460	62,996	59,790	60,762	65,728	67,730	0	0	0	0			
RESERVE ADDITIONS																	
OIL (MMB) CONVENTIONAL	1,470	1,512	1,550	1,584	1,627	1,646	1,377	1,310	1,241	1,174	0	0	0	0			
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
ASSOCIATED GAS (BCF)	1,881	1,984	2,070	2,110	2,161	2,157	1,840	1,697	1,575	1,508	0	0	0	0			
HIGH PERMEABILITY (BCF)	13,089	13,766	14,390	14,397	14,188	12,735	11,806	11,206	11,161	11,017	0	0	0	0			
LOW PERMEABILITY (BCF)	1,965	2,146	2,158	2,065	2,102	1,898	1,952	1,991	2,174	2,212	0	0	0	0			
DEVONIAN SHALE (BCF)	887	821	644	614	522	497	480	460	479	521	0	0	0	0			
COAL BED METHANE (BCF)	1,053	1,124	1,049	1,015	1,118	1,248	1,491	1,665	1,743	2,020	0	0	0	0			
ENHANCED RECOVERY GAS (BCF)	424	444	483	486	486	409	232	208	111	20	0	0	0	0			
ENHANCED RECOVERY TIGHT (BCF)	926	1,141	1,374	1,666	2,047	2,459	2,959	3,579	4,426	5,270	0	0	0	0			
TOTAL NON-ASSOC GAS (BCF)	18,343	19,443	20,097	20,242	20,464	19,245	18,920	19,110	20,094	21,061	0	0	0	0			
TOTAL OIL (MMB)	1,470	1,512	1,550	1,584	1,627	1,646	1,377	1,310	1,241	1,174	0	0	0	0			
TOTAL GAS (BCF)	20,224	21,427	22,167	22,353	22,624	21,402	20,759	20,806	21,670	22,569	0	0	0	0			
TOTAL NGL (MMB)	814	852	877	868	860	784	725	692	707	702	0	0	0	0			
PRODUCTION (W/ LEASE & PLANT GAS)																	
OIL (MMB) CONVENTIONAL	1,664	1,679	1,701	1,721	1,744	1,765	1,771	1,755	1,729	1,694	0	0	0	0			
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
ASSOCIATED GAS (BCF)	2,039	2,040	2,062	2,085	2,113	2,142	2,151	2,138	2,096	2,043	0	0	0	0			
HIGH PERMEABILITY (BCF)	12,499	12,776	12,964	13,224	13,267	13,410	13,270	13,132	12,873	12,705	0	0	0	0			
LOW PERMEABILITY (BCF)	1,781	1,826	1,915	1,945	1,940	1,925	1,901	1,901	1,946	1,951	0	0	0	0			
DEVONIAN SHALE (BCF)	518	535	527	522	514	515	499	506	487	507	0	0	0	0			
COAL BED METHANE (BCF)	1,132	1,140	1,148	1,142	1,153	1,163	1,193	1,232	1,276	1,343	0	0	0	0			
ENHANCED RECOVERY GAS (BCF)	366	360	385	391	382	377	389	377	338	287	0	0	0	0			
ENHANCED RECOVERY TIGHT (BCF)	287	359	448	552	679	834	992	1,225	1,488	1,830	0	0	0	0			
TOTAL NON-ASSOC GAS (BCF)	16,583	16,996	17,387	17,776	17,935	18,224	18,244	18,373	18,407	18,622	0	0	0	0			
TOTAL OIL (MMB)	1,664	1,679	1,701	1,721	1,744	1,765	1,771	1,755	1,729	1,694	0	0	0	0			
TOTAL GAS (BCF)	18,622	19,036	19,449	19,861	20,048	20,365	20,395	20,511	20,503	20,666	0	0	0	0			
TOTAL NGL (MMB)	778	791	803	812	811	816	806	801	793	784	0	0	0	0			
RESERVES																	
OIL (MMB) CONVENTIONAL	15,948	15,780	15,629	15,492	15,376	15,257	14,863	14,419	13,931	13,412	0	0	0	0			
ENHANCED OIL RECOVERY (MMB)	0	0	0	0	0	0	0	0	0	0	0	0	0	0			
ASSOCIATED GAS (BCF)	17,502	17,446	17,454	17,479	17,527	17,542	17,231	16,790	16,269	15,734	0	0	0	0			
HIGH PERMEABILITY (BCF)	80,952	81,942	83,368	84,540	85,461	84,786	83,322	81,396	79,684	77,996	0	0	0	0			
LOW PERMEABILITY (BCF)	19,121	19,440	19,683	19,802	19,964	19,937	19,988	20,077	20,306	20,567	0	0	0	0			
DEVONIAN SHALE (BCF)	5,379	5,665	5,783	5,875	5,883	5,865	5,846	5,800	5,793	5,807	0	0	0	0			
COAL BED METHANE (BCF)	10,967	10,951	10,852	10,725	10,690	10,775	11,073	11,506	11,974	12,651	0	0	0	0			
ENHANCED RECOVERY GAS (BCF)	2,748	2,832	2,930	3,025	3,130	3,162	3,005	2,837	2,610	2,343	0	0	0	0			
ENHANCED RECOVERY TIGHT (BCF)	3,041	3,823	4,749	5,863	7,231	8,855	10,822	13,176	16,114	19,555	0	0	0	0			
TOTAL NON-ASSOC GAS (BCF)	122,208	124,655	127,365	129,830	132,359	133,380	134,056	134,793	136,480	138,918	0	0	0	0			
TOTAL OIL (MMB)	15,948	15,780	15,629	15,492	15,376	15,257	14,863	14,419	13,931	13,412	0	0	0	0			
TOTAL GAS (BCF)	139,710	142,101	144,819	147,310	149,886	150,923	151,287	151,583	152,749	154,652	0	0	0	0			
TOTAL NGL (MMB)	5,838	5,900	5,974	6,030	6,079	6,047	5,966	5,856	5,770	5,688	0	0	0	0			
LEASE AND PLANT GAS (BCF)																	
	1,118	1,141	1,165	1,189	1,199	1,216	1,215	1,221	1,218	1,225	0	0	0	0			

NPCHTS1A: INCENTIVE RATE SENSITIVITY VS NPCHRF3F (#3)

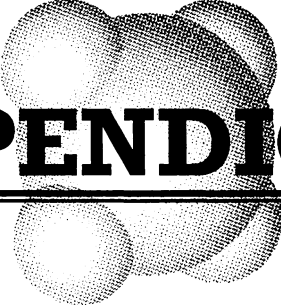
Run Date: 08/30/92

Run Time: 02:36 PM

AVERAGE NATURAL GAS PRICES
(\$1990/MMBtu)

	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
LDC GAS TARIFF PRICES												
AVERAGE AQUISITION	1.76	1.73	1.57	1.55	1.71	1.90	2.12	2.34	2.43	2.59	2.77	2.96
AVERAGE CITYGATE	2.75	2.73	2.53	2.45	2.60	2.77	3.00	3.22	3.29	3.46	3.66	3.84
RESIDENTIAL BURNERTIP	5.71	5.65	5.34	5.22	5.36	5.53	5.75	5.98	6.05	6.23	6.42	6.59
COMMERCIAL BURNERTIP	4.82	4.72	4.45	4.34	4.48	4.65	4.87	5.10	5.17	5.35	5.54	5.72
INDUSTRIAL BURNERTIP	3.07	3.11	2.83	2.74	2.92	3.13	3.40	3.67	3.79	3.99	4.29	4.47
ELEC UTIL BURNERTIP	2.87	2.87	2.67	2.64	2.77	3.00	3.28	3.54	3.62	3.80	4.02	4.20
END USER CARRIAGE PRICES												
AVG SPOT ACQUISITION	1.57	1.49	1.24	1.32	1.51	1.68	1.91	2.12	2.24	2.39	2.56	2.73
AVG SPOT CITYGATE	1.86	1.78	1.53	1.59	1.78	1.97	2.21	2.41	2.52	2.61	2.78	2.96
AVG SPOT BURNERTIP	2.19	2.10	1.84	1.89	2.09	2.29	2.53	2.67	2.73	2.82	2.99	3.17
AVG FIRM BURNERTIP	2.93	2.91	2.70	2.63	2.77	2.95	3.19	3.42	3.50	3.67	3.88	4.06

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2015	2020	2025	2030
LDC GAS TARIFF PRICES														
AVERAGE AQUISITION	2.97	2.95	2.89	2.93	2.80	2.88	2.93	3.17	3.41	3.41	0.00	0.00	0.00	0.00
AVERAGE CITYGATE	3.82	3.77	3.67	3.68	3.51	3.56	3.59	3.83	4.07	4.06	0.00	0.00	0.00	0.00
RESIDENTIAL BURNERTIP	6.56	6.48	6.35	6.34	6.14	6.18	6.20	6.42	6.66	6.63	0.00	0.00	0.00	0.00
COMMERCIAL BURNERTIP	5.70	5.63	5.51	5.51	5.32	5.36	5.38	5.61	5.86	5.83	0.00	0.00	0.00	0.00
INDUSTRIAL BURNERTIP	4.44	4.37	4.24	4.24	4.05	4.12	4.17	4.44	4.70	4.70	0.00	0.00	0.00	0.00
ELEC UTIL BURNERTIP	4.18	4.11	4.00	4.01	3.82	3.87	3.90	4.16	4.41	4.38	0.00	0.00	0.00	0.00
END USER CARRIAGE PRICES														
AVG SPOT ACQUISITION	2.78	2.78	2.73	2.78	2.67	2.78	2.84	3.11	3.35	3.39	0.00	0.00	0.00	0.00
AVG SPOT CITYGATE	2.98	3.03	3.00	3.04	2.90	3.00	3.06	3.33	3.57	3.61	0.00	0.00	0.00	0.00
AVG SPOT BURNERTIP	3.19	3.26	3.34	3.38	3.24	3.34	3.40	3.68	3.93	3.97	0.00	0.00	0.00	0.00
AVG FIRM BURNERTIP	4.05	4.00	3.89	3.90	3.72	3.77	3.81	4.06	4.31	4.30	0.00	0.00	0.00	0.00



APPENDICES



The Secretary of Energy
Washington, DC 20585

June 25, 1990

Mr. Lodwrick M. Cook
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Cook:

Through this transmittal, I am formally requesting that the National Petroleum Council (NPC) perform two studies that are currently of critical interest to the Department of Energy. These studies are described below.

Constraints to Expanding Natural Gas Production, Distribution and Use

I request that the NPC conduct a comprehensive analysis of the potential for natural gas to make a larger contribution, not only to our Nation's energy supply, but also to the President's environmental goals. The study should consider technical, economic and regulatory constraints to expanding production, distribution and the use of natural gas. In the conduct of this study, I would like you to consider carefully the location, magnitude and economics of natural gas reserves, and the projected undiscovered and unconventional resource; the size, kind and location of future markets; the outlook for natural gas imports and exports; and potential barriers that could impede the deliverability of gas to the most economic, efficient and environmentally sound end-uses.

This study comes at a critical time, given the increased interest in natural gas, for developing public and private sector confidence that natural gas can make a greater contribution to the energy security and environmental enhancement of our Nation. I anticipate that the results of your work will be able to contribute significantly to the development of the Department's policies and programs.

The U.S. Refinery Sector in the 1990's

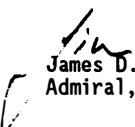
U.S. refineries face significant changes to processing facilities in the next decade, particularly in response to new environmental legislation that will affect emissions and waste disposal from refineries and the composition of motor fuels. Substantial investments are likely to be required to comply with proposed Clean Air Act Amendments, including provisions dealing with air toxics and alternative fuels. There is concern about the U.S. engineering and construction industry's capability to design, manufacture, and install quickly the large number of new, sophisticated processing facilities that would be necessary to supply these fuels.

Product imports, which are projected to increase, may also have to be treated differently than in the past. For example, if U.S. refiners have different gasoline specifications (e.g., Reid Vapor Pressure, aromatics, olefins, oxygen content) than foreign refineries, imported products may require additional U.S. refining.

I request that the NPC assess the effects of these changing conditions on the U.S. refining industry, the ability of that industry to respond to these changes in a timely manner, regulatory and other factors that impede the construction of new capacity, and the potential economic impacts of this response on American consumers.

I look forward to receiving your results from these two studies and would like to be notified of your progress periodically.

Sincerely,


James D. Watkins
Admiral, U.S. Navy (Retired)

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council on June 18, 1946. In October 1977, the Department of Energy was established and the Council was transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to oil and natural gas or the oil and gas industries. Matters that the Secretary of Energy would like to have considered by the Council are submitted in the form of a letter outlining the nature and scope of the study. This request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Secretary of Energy include:

- *Unconventional Gas Sources* (1980)
- *Emergency Preparedness for Interruption of Petroleum Imports into the United States* (1981)
- *U.S. Arctic Oil & Gas* (1981)
- *Environmental Conservation—The Oil & Gas Industries* (1982)
- *Third World Petroleum Development: A Statement of Principles* (1982)
- *Enhanced Oil Recovery* (1984)
- *The Strategic Petroleum Reserve* (1984)
- *U.S. Petroleum Refining* (1986)
- *Factors Affecting U.S. Oil & Gas Outlook* (1987)
- *Integrating R&D Efforts* (1988)
- *Petroleum Storage & Transportation* (1989)
- *Industry Assistance to Government* (1991)
- *Short-Term Petroleum Outlook* (1991)
- *Petroleum Refining in the 1990s—Meeting the Challenges of the Clean Air Act* (1991).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of the oil and gas industries and related interests. The NPC is headed by a Chairman and a Vice Chairman, who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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for description of regions.

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2	New Jersey and New York
3	Delaware, Maryland, Pennsylvania, Virginia, Washington, D.C., and West Virginia
4	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee
5	Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin
6	Arkansas, Louisiana, New Mexico, Oklahoma, and Texas
7	Iowa, Kansas, Missouri, and Nebraska
8	Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming
9	Arizona, California, and Nevada
10	Idaho, Oregon, and Washington

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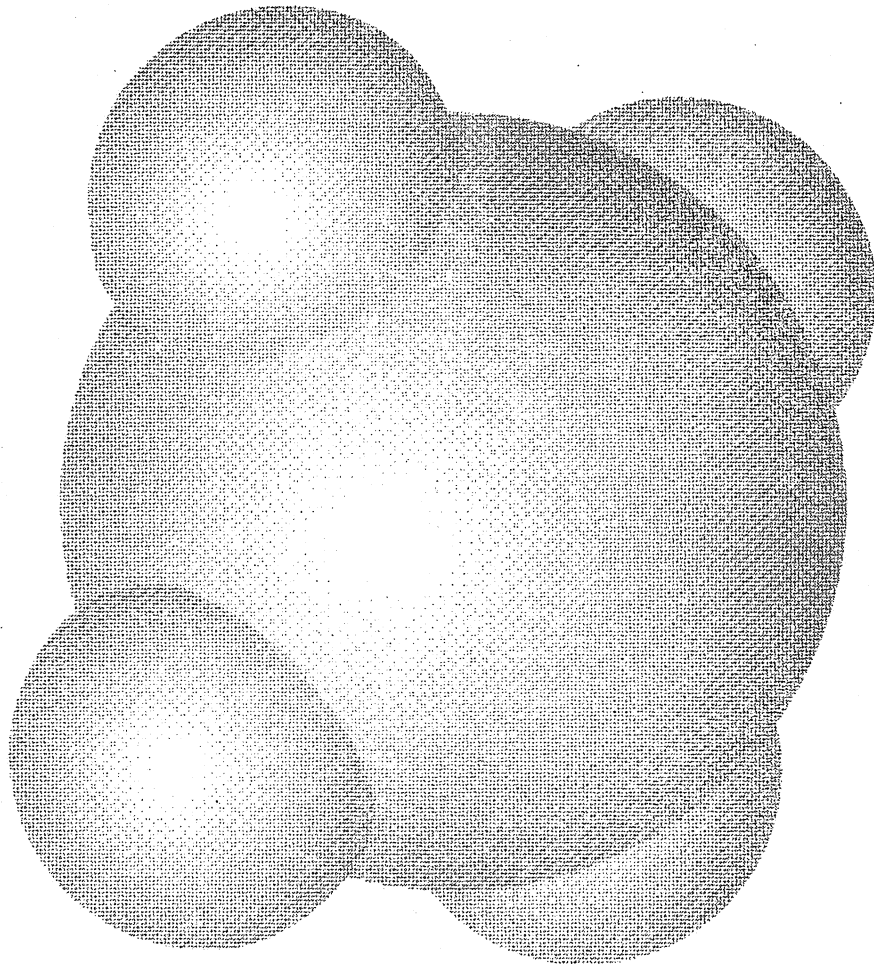
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