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TRAINING SEMINARS IN ENERGY PRICING

POLAND

PROCEEDINGS

PREPARED BY:

INTERNATIONAL RESOURCES GROUP, LTD.
Washington, DC

U.S. EMERGENCY ENERGY PROGRAM FOR EASTERN & CENTRAL EUROPE

U.S. AGENCY FOR INTERNATIONAL DEVELOPMENT
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WASHINGTON, DC 20523

June 1992

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INTRODUCTION

Assisting in the transition to market economies is one of the principal areas of emphasis in the U.S. strategy to aid the new democracies in Eastern and Central Europe[1] (ECE). At an early stage in the process of transition to democracy and a free market economy, the U.S. Agency for International Development (USAID) recognized that instituting rational pricing and taxation systems is of critical importance in energy and other sectors. Under the former centrally-planned economic system in the ECE region, energy prices were heavily subsidized and did not reflect world price levels or the economic costs of production. This resulted in widespread distortions in energy resource allocation, consumption and energy efficiency. In addition, with the declines in Soviet oil deliveries, higher international oil prices, and the switch to hard currency payments for Soviet oil and gas in January 1991, the ECE countries are faced with difficult decisions on the nature and rate of price reform.

In order to support the ECE countries in their efforts to rationalize and reform their energy price systems, USAID developed a technical assistance package entitled *Design of Energy Price Reform Program* (Component 4) under the USAID-funded **Emergency Energy Program in Eastern and Central Europe**. The broad goals of this Component were to assess the current pricing regime, identify critical issues confronting the Government of Poland, evaluate the analytical resources available to various host-country institutions, to assess the impact of energy price reforms, and to provide training to improve the government's analytical capabilities on pricing issues.

Contractor Team

International Resources Group, Ltd. (IRG) was selected in February 1991 as USAID's prime contractor to carry out this technical assistance in Poland. Working with IRG on this task was a number of fuel-specific experts.

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1 Refers to Bulgaria, the Czech and Slovak Federal Republic, Hungary, Poland, and Romania. However, these proceedings cover Poland only.

Technical Assistance

The IRG Team performed the following energy pricing technical assistance in Poland:

- monitored existing price levels and changes for each fuel (petroleum products, gas, coal, and electricity) over the life of the contract

- evaluated the pricing policy decision-making process (and responsibilities/functions of various government ministries/agencies);

- analyzed the reforms already undertaken by the Government by the commencement of the contract, as well as those implemented since February 1991 and policies/reforms under consideration for future implementation;

- examined the critical issues confronting the Government as the reform process evolved, particularly the social and political impact of changing (increasing) price levels, and;

- assessed the modeling and other analytical capabilities of those institutions involved in the energy pricing research/analysis and policy process.

Based on this ongoing assessment and feedback process, IRG identified the key pricing issues and fuel sectors that were of greatest interest to the host-country institutions. IRG then designed in-country training programs to address these issues, which included hands-on or "how to" discussions of pricing in the petroleum products, electricity, coal, and natural gas sectors. These training seminars included discussions of theoretical regulated and free market pricing concepts used in the West, comparative views of pricing systems around the world, and the applicability of different systems and concepts to the energy economy in Poland.

The participants attending the seminars represented a wide spectrum of individuals involved in the energy pricing system, including government agencies, suppliers, and end-users. Participants typically were from: the Ministries of Industry and Finance; key energy producers such as oil, gas and coal production companies,

refineries, or power generators; transportation and distribution entities (T&D) such as natural gas distribution companies, and electricity T&D organizations, and; large industrial consumers such as steel and chemical plants.

During the week of May 28, 1991, IRG visited Poland to meet with the counterpart representatives of the Polish Government and other organizations, including representatives from the oil, coal, gas, and the electricity sectors (the latter being the Polish Power Grid). The purpose of this Definitional Mission was to assess the current status of energy price reform in the country and examine the decision-making process, including the responsibilities and analytical capabilities of various institutions, as well as to receive feedback on the critical pricing reform issues confronting the country. IRG identified technical assistance needs and training seminar content designed to aid the government in its efforts to implement an economically rational and politically feasible system of price reforms. Thus, from these discussions with the host-country counterparts, IRG designed an *Energy Pricing Seminar.*

Based on observations made in the aftermath of the initial Seminar and over the course of the contract, as well as in collaboration with the Government, it became clear that the natural gas industry in Poland is poised for considerable growth in the next decade. The need to diversify energy sources, to develop cleaner fuels to limit adverse environmental impact, and to provide energy for continued economic growth and development has placed increasing importance on the role of natural gas. In order to assist the country in negotiating effectively for gas supplies and to provide assistance in the implementation of appropriate gas pricing policies and reforms, IRG developed further training. a *Natural Gas Ratemaking Seminar.*

This volume is a report on these two training sessions conducted in Poland.

ENERGY PRICING SEMINAR

WARSAW, POLAND

September 4-6, 1991

Sponsored By:

U.S. Agency for International Development
Emergency Energy Program in Eastern and Central Europe

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POLAND ENERGY PRICING SEMINAR

AGENDA

September 4, 1991

General Session

9:00 - 10:30	Introduction to Energy Pricing Principles
10:45 - 12:00	Policy Implications of Energy Pricing Strategies -- Experiences/Lessons of Other Countries
12:00 - 1:00	Overview Presentation of the Major Fuels
Lunch	

Fuel-Specific Sessions

2:00 - 6:00 At Ministry of Industry and Trade:

Crude Oil and Petroleum Products (Mr. Dutkiewicz)
Coal (Mr. Huetteman)

At Polish Oil and Gas Company:

Natural Gas (Dr. Schlesinger, Dr. Ebinger)

At Polish Power Grid:

Electricity (Dr. Hertzmark, Mr. Borlick)

September 5, 1991

Fuel-Specific Sessions (all day)

September 6, 1991

General Session: Wrap-Up

9:00 - 10:30	Summary Presentations of Fuel-Specific Sessions
11:00 - 12:00	Major Energy Pricing Issues for Poland
12:00 - 1:00	Questions and Answers

ENERGY PRICING SEMINAR
Warsaw, Poland

SPEAKERS

Mr. John Banks

Mr. Banks is a Senior Associate with the Washington, D.C. consulting firm of IRG. He specializes in the economic and political analysis of oil and petroleum products markets in developing and Eastern/Central European countries. His expertise covers energy pricing regimes and policies, supply and demand analysis, as well as consumption and production patterns. Mr. Banks has extensive experience working with senior energy officials in Eastern and Central Europe, especially in identifying technical assistance needs and implementing aid programs and projects. Mr. Banks has organized and managed energy conferences and seminars in Bulgaria, the Czech and Slovak Federal Republic, Hungary, Poland, and Romania. He served as Project Manager for two components of USAID's Emergency Energy Program in Eastern and Central Europe.

Mr. Robert Borlick

Mr. Borlick has over fifteen years experience conducting analyses and providing counsel to the electric utility industry. He has broad and diversified professional expertise in economic and financial analysis, strategic planning, and operations research. Mr. Borlick has carried out generating capacity studies for a dozen different utility systems, and has evaluated the economic attractiveness of independent power projects. He has performed management audits of the integrated resource planning activities at a number of electric and gas utilities. For the management consulting firm of Putnam, Hayes & Bartlett, Mr. Borlick was one of the principal advisors to the UK government on the privatization of the electric utility industry.

Mr. Bronek Dutkiewicz

Mr. Dutkiewicz is an independent consultant with thirty years experience specializing in economics, planning, and business development in the international oil

and chemical industries. He has extensive experience working with developing country governments in analyzing energy pricing policies (particularly petroleum products prices) in order to address problems in energy utilization and availability. Mr. Dutkiewicz also has significant expertise in the design and application of refinery modelling systems. Prior to becoming an independent contractor, he held several senior-level positions in the energy industry: Vice President of Commercial Development at Dynalectron Corporation; Vice President of Financial Research with Butcher and Singer, Inc. on Wall Street, and; numerous positions in engineering, construction, and operations of oil and chemical facilities throughout the world. Recently he has conducted World Bank Missions examining the refining sector in Poland and the oil sector in general in the Czech and Slovak Federal Republic.

Dr. Charles K. Ebinger

Dr. Ebinger is Executive Vice President of International Resources Group, a Washington, D.C.-based consulting firm specializing in energy, natural resources, and the environment. He is an internationally-recognized expert on global crude oil and petroleum products markets, as well as energy pricing issues. Dr. Ebinger has conducted numerous consulting assignments for multinational corporations, governments, international financial institutions, and regional development banks. He is the author of five books and over 200 hundred articles. In addition, Dr. Ebinger serves in the following positions: Crude Oil Editor at Octane Week; Member of the Editorial Board of The Geopolitics of Energy; Director of North Coast Energy, Cleveland, Ohio; Director of the Kokomo Gas Corporation, Kokomo, Indiana, and; Adjunct Professor of International Energy at the School of Foreign Service at Georgetown University in Washington, D.C.

Dr. Donald Hertzmark

Dr. Hertzmark is an independent consultant with extensive experience in natural resource and development economics, energy and petroleum economics, energy pricing, project financial and economic evaluation, and international trade and macroeconomic analysis. He specializes in pricing and tariff economics, energy market

analyses, and economic and financial feasibility studies for energy projects and programs. Dr. Hertzmark's energy pricing experience has involved extensive work developing and implementing models, including training in the design, operation, and maintenance of these modeling tools. He has worked on pricing projects involving a wide variety of fuel sources including petroleum, natural gas, coal, and electricity. Dr. Hertzmark has experience in numerous developing countries including the Ivory Coast, Morocco, India, Indonesia, Thailand, Pakistan, the Philippines, and Turkey. During the period 1991-1992, he has been working for USAID on energy pricing issues in Hungary, Poland, and Bulgaria.

Mr. Thaddeus Huetteman

Mr. Huetteman is a Director of the Fuel Practice for Energy Management Associates, Inc. (EMA). He has spent more than a decade working on the impact of environmental regulation on energy companies. Mr. Huetteman's professional experience ranges from economic forecasting fossil fuel market conditions to assessment of rate and financial effects of government policies. He has developed a fuel purchase evaluation tool combining SO_2 allowance valuation, coal quality impacts on boiler performance and a generating unit commitment algorithm. Prior to joining EMA, he served as editor-in-chief of *Compliance Strategies Review*, a trade newsletter assessing the response of electric utilities to the Clean Air Act Amendments of 1991. From 1986-1989, Mr. Huetteman was Director of DRI/McGraw Hill's Coal Service, where he managed a staff providing analytical and forecasting services in coal markets for clients in the electric and coal industries.

Dr. Benjamin Schlesinger

Dr. Schlesinger is President of Benjamin Schlesinger and Associates, a Washington-based consulting firm specializing in all phases of natural gas markets. He has detailed knowledge of engineering and technical issues related to exploration, development, transmission, and distribution. Dr. Schlesinger's expertise includes regulatory, financial, and economic analysis as well as corporate strategic planning, legal, accounting and management/organizational issues. He assists clients in

developing and restructuring natural gas purchasing strategies and analyzing new gas marketing mechanisms and programs. Dr. Schlesinger has conducted numerous international natural gas studies including extensive work in Europe: Austria, Belgium, Holland, Germany, and the United Kingdom. He assisted IRG in conducting training in natural gas pricing issues in Bulgaria and Poland.

ENERGY PRICING SEMINAR

Warsaw, Poland
September 4-6, 1991

SUMMARY REPORT OF PROCEEDINGS

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SUMMARY REPORT OF PROCEEDINGS

ENERGY PRICING SEMINAR
Warsaw, Poland

September 4-6, 1991

The *Energy Pricing Seminar* consisted of three days of meetings held during the period September 4-6, 1991. The meetings were attended by approximately 55 people from Polish energy industries as well as government agencies and institutions. The participants represented the electric power, coal, oil, and gas sectors. The IRG Team presenting this seminar and their responsibilities/areas of expertise are listed below:

- Dr. Charles K. Ebinger, Team Leader, Policy Overview and Context, Macroeconomic Implications.
- Mr. John P. Banks, Project Manager/Seminar Coordinator
- Mr. Robert Borlick, Electricity Pricing
- Dr. Donald Hertzmark, Principles of Energy Pricing, Electricity Pricing
- Dr. Benjamin Schlesinger, Natural Gas
- Mr. Bronek Dutkiewicz, Oil and Petroleum Products
- Mr. Thaddeus Huetteman, Coal

The seminar opened with a General Session of all the participants to discuss broad pricing topics relevant to all the energy subsectors. The issues discussed included an introduction to pricing principles, the policy implications of pricing strategies, and a brief examination of the experiences/lessons of several other countries. An overview presentation was made covering each of the major fuels and the primary aspects relevant to Poland. Specifically, there was a discussion of electricity issues, including a look at recent U.S. and UK experiences in their respective power industries.

Beginning in the afternoon of the first day and throughout the second day the participants were divided into separate, specialist sessions to discuss topics specific to

the individual fuel subsectors. On the third day a General Wrap-Up Session was convened during which each member of the IRG Team summarized the highlights of the specialist sessions. The closing session also included an extensive Question and Answer period.

The following is a summary of the topics discussed during the specialist sessions on the second day.

Dr. Schlesinger discussed the following issues concerning natural gas pricing:

- how rate-making works;
- how tariffs are designed to accommodate different end-users;
- gas supplies, including
  - U.S. gas supplies (and pipeline network) mostly domestic,
  - W. Europe supplies from external sources (principally Algeria, USSR, Norway, and the Netherlands), and
  - supplies available to Poland -- methods and strategies to take advantage of lower cost local energy vs. distant suppliers;
- market structure and ways the business is organized and how it is different in Europe, especially,
  - hard lessons from U.S. gas price regulatory experience,
  - compare & contrast W. Europe with the U.S., and
  - examination of the Polish model;
- gas demand, particularly
  - rate-making mechanisms -- firm (commitment of pipeline capacity) vs. interruptible (excluding fixed charges), and
  - various demand charges -- fixed charge to rent capacity, charge for actual gas as it flows (based on operating & maintenance costs); and price of the commodity, ie. the gas itself;
- how conservation affects gas sales and what factors drive the residential market;

- natural gas and electric power -- use of combined cycle turbines, and;
- discussion of the newer types of markets developing in the U.S. -- air quality market where gas replaces coal under certain special circumstances to reduce toxic air emissions, improved efficiency, and natural gas vehicles (NGVs).

Mr. Huetteman discussed the following issues during the specialist session on coal:

- the critical role of coal in the Polish economy -- opportunities and risks;
- pricing competitiveness of Polish coal, specifically
  - an examination of the pricing of high quality, low-sulphur coal from Colombia and South Africa -- identification of a price at which Polish coal would be competitive[1];
- coal quality issues, particularly
  - increasing environmental regulations in Western Europe,
  - higher heating values and the implications of burning different types of coal to produce electricity, and
  - U.S. experience -- burning higher quality coals to improve production costs of electricity at the boiler;
- restructuring of the Polish coal industry
  - sizing criteria -- limits on maximum and minimum size of new companies in order to prevent the emergence of monopolies or "weak sisters," and
  - promoting a balance of more or less profitable mines among companies;
- lessons from the U.S. experience on fuel switching based on environmental regulations

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1 The competitive price of Polish coal was $44-$45/metric ton at Baltic ports. Given a $10/metric tonne domestic transportation cost, the competitive price becomes $30-$35/metric tonne at minemouth.

- increasing importance of examining the economics of price differentials among various coal qualities,

- increase in burning non-traditional types of coal, such as metallurgical coals, and

- U.S. Clean Air Act and a new era of environmental legislation.

Mr. Borlick and Dr. Hertzmark covered the following topics during the session on electricity:

- objectives attainable through proper electricity pricing;

- proposed restructuring of the Polish power industry into three component businesses -- generation, transmission, and distribution;

- developing the marginal costs of each of the three businesses;

- why prices charged by each business should be set equal to its marginal costs;

- processes of designing retail tariffs for recovering all costs from the end-use customers while also providing the correct economic (price) "signals;"

- role of prices paid to generating companies in determining how much new generating capacity gets built;

- need for imposing some form of price regulation on the transmission and distribution businesses to control the monopoly power that will necessarily exist in those businesses; and

- compare and contrast the U.S. and U.K. approach to regulating transmission and distribution prices.

Mr. Dutkiewicz's presentation consisted of a review of oil prices and influential factors in the international oil market in general and specifically in the United States. Topics included:

- crude oil prices;

- U.S. petroleum products (prices and consumption)
    - the transportation sector,
    - household energy use, and
    - power generation usage;
- petroleum production costs -- U.S. experience
    - production cost breakdown,
    - refinery operating costs and margins, and
    - co-product pricing;
- petroleum product prices
    - major factors determining prices,
    - relative product prices,
    - product price scenarios, and
    - taxes;
- pricing policy
    - mode, objectives, and mechanisms;
- U.S. oil policy history;
- international prices during the 1980s, and;
- future outlook

Significant Observations from the Seminar

One area of special interest among the participants was the concept of price differentiation among coals of varying qualities, especially the competitiveness of Polish coal in European environmentally-regulated markets. Mr. Huetteman and the participants established that high-quality Polish coal (relative to West European coals) together with increasing demand for cleaner burning, higher quality coal in Western Europe will increase the competitiveness of Polish coal. Another key factor affecting in this area is that the world price for high quality coal will undoubtedly rise in Western Europe in the near future and that coal-fired power plants have a greater tolerance for using different quality coals in the same plant. In addition, Germany's plan to cut the

utilization of lignite in the eastern part of that country by two-thirds presents a significant opportunity for delivery of Polish coal into this market.

However, world markets lag behind in valuing higher quality coals appropriately: many economic, financial and environmental aspects of coal utilization are not yet fully factored into cost and pricing calculations. Valuing the costs of reducing pollution must be considered as an important additional factor in coal pricing. Incorporation of competitive SO_2 reduction costs is imperative when evaluating investments in coal quality in Poland. In Poland, there is a need to develop/enhance skills required in evaluating coal qualities in order to determine if a particular investment in higher quality coal is warranted. This allows the capital constrained industry to concentrate on more profitable coals. Future technical assistance could encompass a market study examining European coal markets, types of coal in demand, price regimes for various qualities, and the competitiveness of Polish coal based on these findings.

Finally, whatever policies are undertaken to restructure the Polish coal industry will encounter risks in social disruption and shifts in employment.

Dr. Schlesinger suggested that from a policy, strategic and financial standpoint it makes sense for Poland to develop and utilize domestic and nearby **natural gas** resources, as well as coal seam gas, before committing capital resources to major long-range, high-cost international pipeline and transportation projects. The observation was made that Poland's natural gas Reserves-to-Production (R/P) ratio appears too high and that the country should be producing more gas. In addition, it is clear that strategically Poland is at the nexus of regional gas marketing: gas from domestic sources as well as Norway and Russia will clearly compete in the future. These factors create the opportunity for additional technical assistance to examine the domestic market for natural gas as well as to assess wellhead and transport costs (in particular the capacity and extent of the distribution system). This analysis would reveal more about the appropriate price of natural gas and the price competitiveness among various sources: eg., Norway and Russia. In addition, more detailed training and instruction on

ratemaking and tariff design is required. These views and observations generated great interest among the participants.

Another major topic of discussion centered on the methodology of pricing intermediate **petroleum products** and the allocation of production costs to specific operations within refinery/petrochemical complexes. The use of models, marginal cost allocation concepts, and the role of exogenous price factors were discussed in depth.

ENERGY PRICING SEMINAR

Warsaw, Poland
September 4-5, 1991

LIST OF PARTICIPANTS

LIST OF PARTICIPANTS

ENERGY PRICING SEMINAR
Warsaw, Poland

September 4-6, 1991

Coal

Brown Coal Board

1. Tadeusz Bartoszak
2. Ewa Sledz
3. Tomasz Rybczynski

Polish Coal Agency

4. Teresa Kania
5. Jerzy Wrzesniewski
6. Antoni Madejski

Polish Academy of Sciences

7. Stanislaw Blaschke
8. Eugeniusz Mokrzycki
9. Zbigniew Grudzinski
10. Wieslaw Blaschke

Energy Institute

11. Jan Solinski

Ministry of Industry and Trade

12. Andrzej Brewczynski
13. Jerzy Retke
14. Janusz Stepniewski

LIST OF PARTICIPANTS
(continued)

Center for Energy Information

15. Danuta Zaborske

Oil & Petroleum Products

Petrochemia-Piock

16. Maria Krysztofik

Czechowice Refinery

17. Urszula Cholcio

Trezebinia Refinery

18. Jozef Piekarz

Ministry of Industry and Trade

19. Stefan Olczyk

Center for Energy Information

20. Danuta Zaborske

Ciech Petrolimpex

21. Darius Gwozdz
22. Gregor Kozakowski

LIST OF PARTICIPANTS
(continued)

Electricity

Polish Power Grid

23. Teresa Kierpiczow
24. Wladyslaw Zawalik
25. Henryk Malysa
26. Janusz Siemianowski
27. Halina Gogo
28. Elzbieta Ostaszewska
29. Wanda Odowska
30. Barbara Suwinska
31. Ewa Dabrowska
32. Mieczyslaw Chalupka
33. Lujan Twardy
34. Kujda Kazimierz

Center for Energy Information

35. Wlodzimierz Liszak
36. Stefan Skrzte
37. Grazyna Bromszewski

Natural Gas

Polish Oil & Gas Company

38. Andrzej Brach
39. Magdalena Reszczynska
40. Elzbieta Brozczak
41. Alakesnader Magiera
42. Maria Kaczorowska
43. Piotr Lubienski
44. Bozena Klinger

Energy Institute

45. Ewa Walczykowska
46. Katarzyna Micholczuk
47. Hanna Bartoszewicz

LIST OF PARTICIPANTS
(continued)

General Sessions *

Ministry of Finance

48. Stefan Lober
49. Teresa Kubacka

Ministry of Industry & Trade

50. Przemyslaw Zawadzki
51. Lidia Nagrodkiewicz
52. Tadeusz Capala
53. Mariola Linkiewicz
54. Antoni Wolkowski

* Most of the individuals listed above in the separate fuel-specific sessions also attended both General Sessions.

ENERGY PRICING SEMINAR

Warsaw, Poland
September 4-6, 1991

PRESENTATION MATERIALS

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PRICING ELECTRICITY IN POLAND

By
Robert L. Borlick

International Resources Group, Limited

September 4-6, 1991

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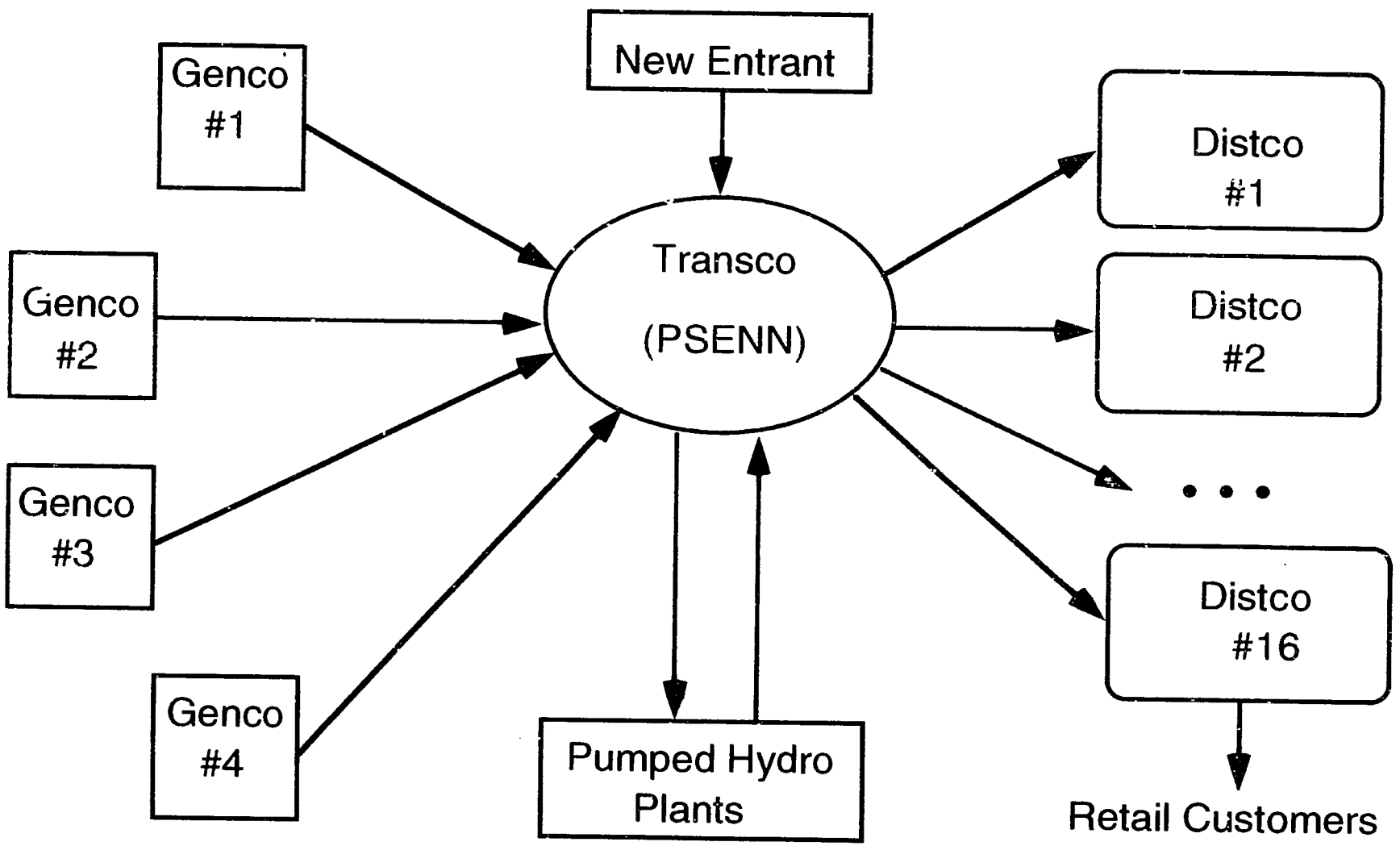
MARGINAL COST- BASED PRICES

- Encourage efficient use by consumers.
- Promote least-cost electricity service
- Support adequacy of supply.
- Provide revenues sufficient to make the industry self-supporting

POWER INDUSTRY STRUCTURE

- Deregulated competitive generation companies ("Gencos").
- An independent transmission company ("Transco").
- Regional distribution companies ("Distcos").

ELECTRICITY SALES BETWEEN SECTORS



PRICING OF GENERATION

- A deregulated, competitive generation sector will set prices through competitive bidding.

- If truly competitive the Gencos will bid prices close to their marginal costs of production.

- Clearly, maintaining competition among generators is critical.

LONG-TERM VS.SHORT-TERM PRICES

- Gencos can sell their full output to Transco through short-term (hour-by hour) price bids

- Alternatively, they can sell to Distcos and large customers through long-term contracts.

- Contract prices will be determined by expected future system hourly prices; however, the risk will be shifted.

COORDINATING GENERATION OPERATIONS

- Generating plant operations must be coordinated:
  - Choosing the generating units needed to meet each day's peak demand
  - Loading the units in merit-order
  - Scheduling units for periodic maintenance.

PEAK LOAD CONGESTION PRICING

- For each KWh delivered, each operating generator will receive the highest price bid for that hour.

- In addition, each generator will receive a congestion charge for each KWh delivered during *peak* hours.

- The purpose of the congestion charge is to ensure that electricity demand seldom exceeds available generating capacity.

PRICING OF TRANSMISSION

- The marginal costs of transmission services is extremely complex.
- Optimal spot pricing theory offers a way to price transmission services but has only been solved for simple systems.
- Generally, transmission costs are treated as being fixed.
- The exception is transmission losses which are marginal costs.

PRICING OF DISTRIBUTION

- Unlike transmission costs, most distribution costs are truly fixed.
- The one exception is distribution losses.
- Distribution costs vary greatly by voltage level.
- Customer classes can be classified by voltage level and costs assigned accordingly.

RETAIL PRICING

- Retail Prices are designed to recover all the costs of providing electric service.
  - generation costs
  - transmission costs
  - distribution costs
  - supply costs.
- These costs include both marginal costs and fixed costs.

RETAIL TARIFF DESIGNS

- Ideally, fixed costs are recovered through periodic standing charges.
- Marginal costs are recovered through prices applied to customers' maximum KW demand and KWh usage.
- To the extent practical, marginal cost-based prices should vary with time of use.

GENERATION PLANNING

- Traditionally, generation additions have been centrally planned.
  - The US uses regional committees representing the utilities
  - In the UK the Central Electricity Generating Board (CEGB) did it.
- The UK now relies on spot electricity prices to provide market incentives for adding generating capacity.

IS CENTRAL PLANNING BEST?

- The central planning approach has ensured high reliability in both countries.
  - But in both countries substantial excess capacity was built in the 1980s.
  - Most of the cost of that capacity was borne by the customers.

IS THE MARKET APPROACH BEST?

- The market-based approach places all of the risks and rewards on the Gencos.
  - But that may not ensure adequacy of supply.
  - Also, severe swings in electricity prices may result.

NEED FOR COMPATIBLE STRUCTURE

- Ultimately, the success of any pricing scheme depends on adopting a compatible industry structure.
- Specific provisions must be made for:
  - ensuring competition in generation
  - price regulating the transmission and distribution natural monopolies
  - coordinating generation operations
  - coordinating generation planning (?).

PRICING ELECTRICITY IN POLAND

By
Robert L. Borlick

International Resources Group, Limited

September 4-6, 1991

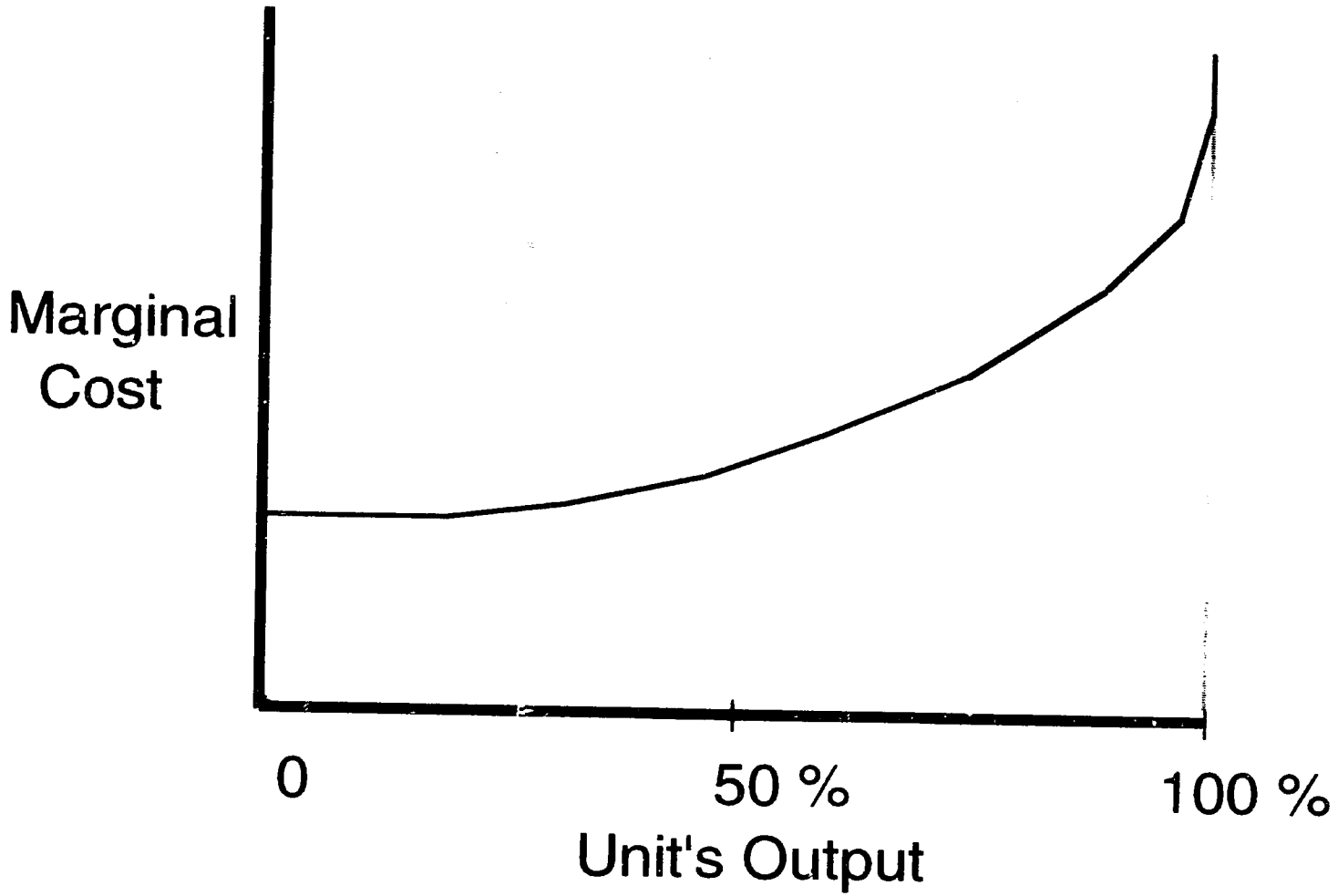
ELECTRICITY PRICING OBJECTIVES

- Encourage efficient use by consumers.
- Supply electricity at lowest cost.
- Ensure adequacy of supply.
- Promote price stability.
- Provide revenues sufficient to make the industry self-supporting.

MARGINAL COST OF GENERATION

- The power system's marginal cost of generation is determined by:
  - the marginal costs of the individual generating units
  - the available generating capacity relative to electricity demand.

GENERATING UNIT MARGINAL COST



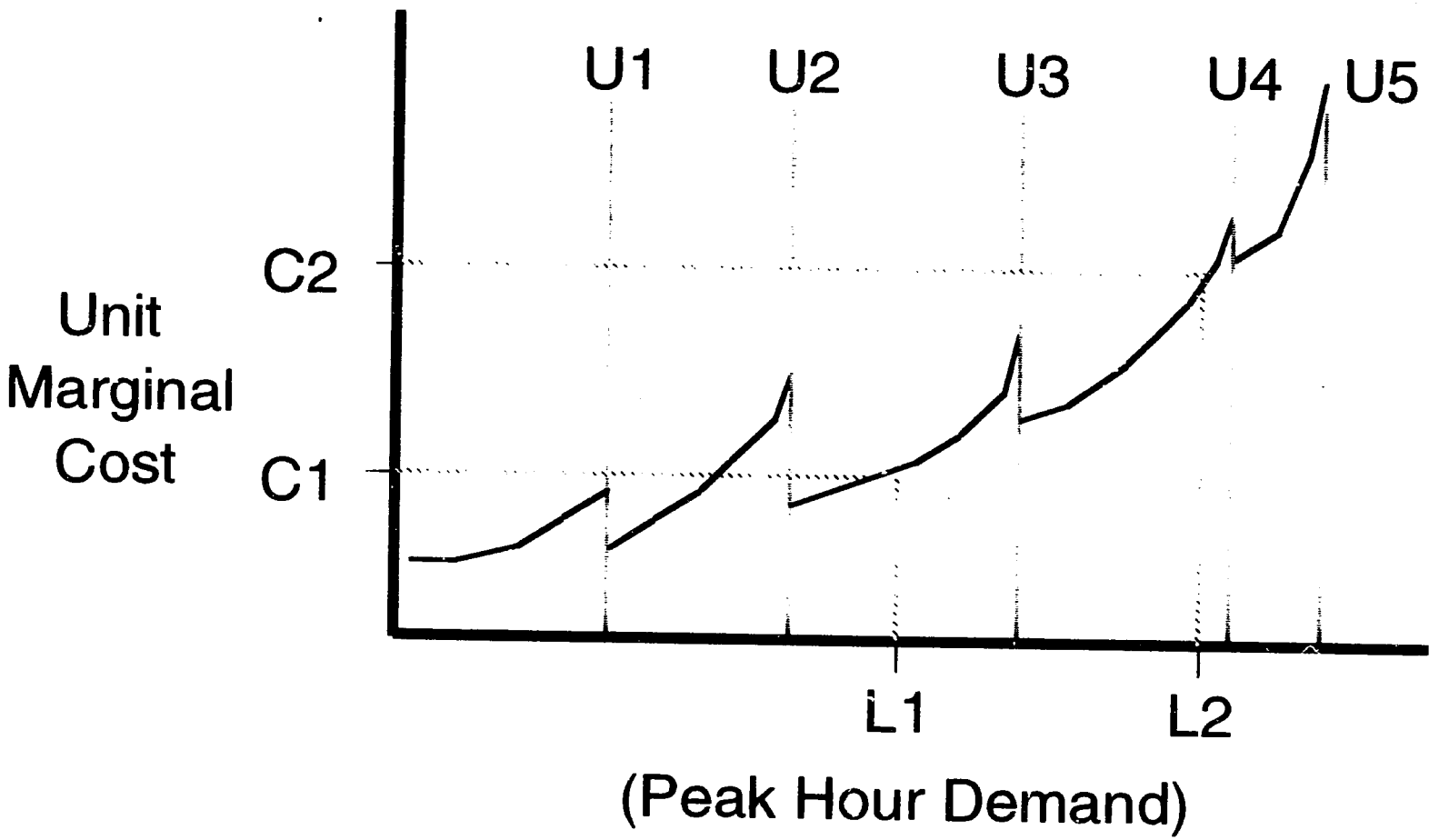
MERIT- ORDER DISPATCH OF UNITS

- Generating units are dispatched in "merit-order"

  - Lowest cost units are loaded first, followed by higher cost units until demand is satisfied.

  - All partially loaded units have the same marginal cost.

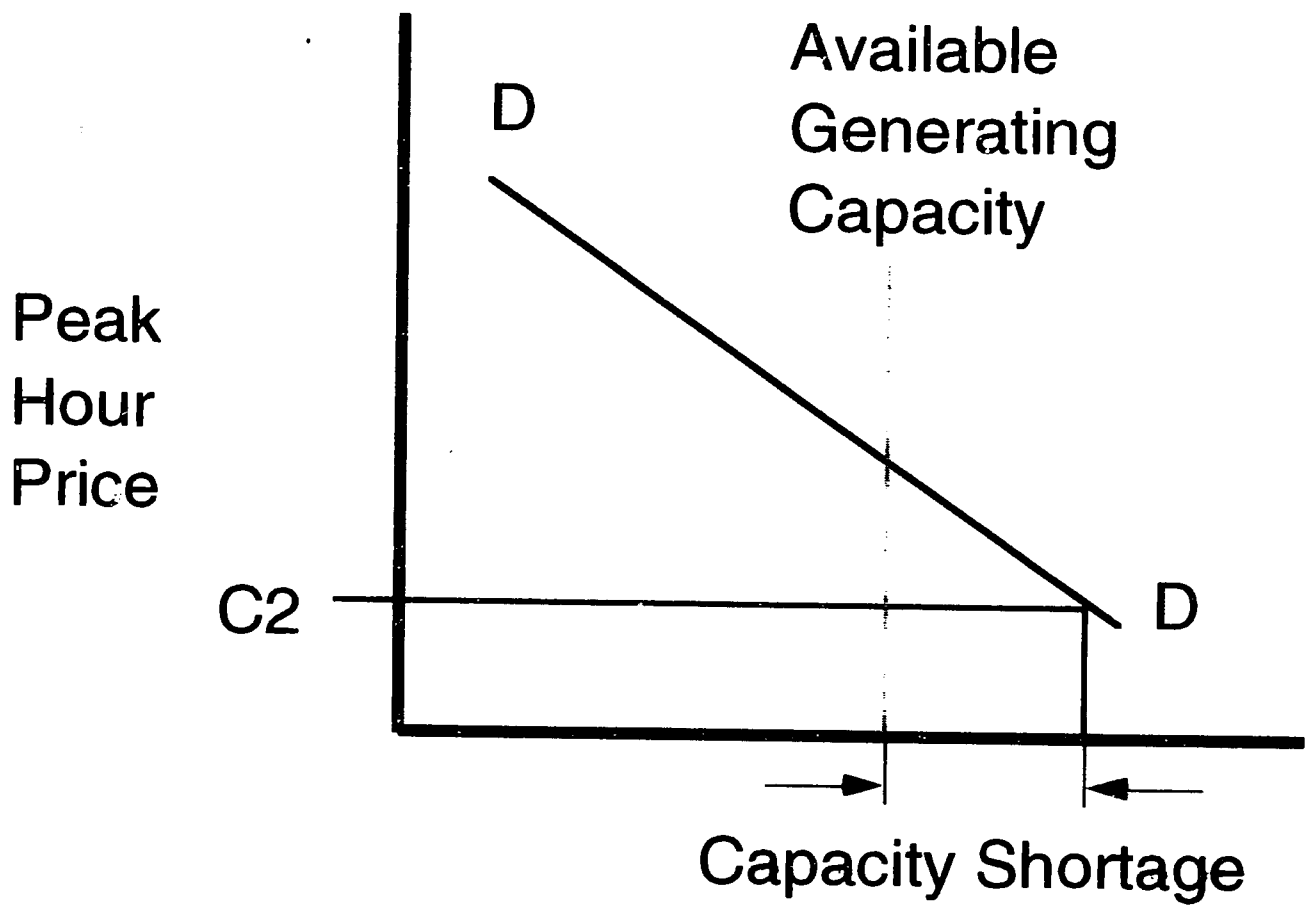
EXAMPLE: MERIT- ORDER DISPATCH



SYSTEM MARGINAL COST

- The system's hourly marginal cost of generation equals:
  - the marginal cost of the highest cost generating unit producing electricity if system is not capacity constrained.
  - the marginal cost of that unit plus an "outage cost" if demand is close to available capacity in that hour.

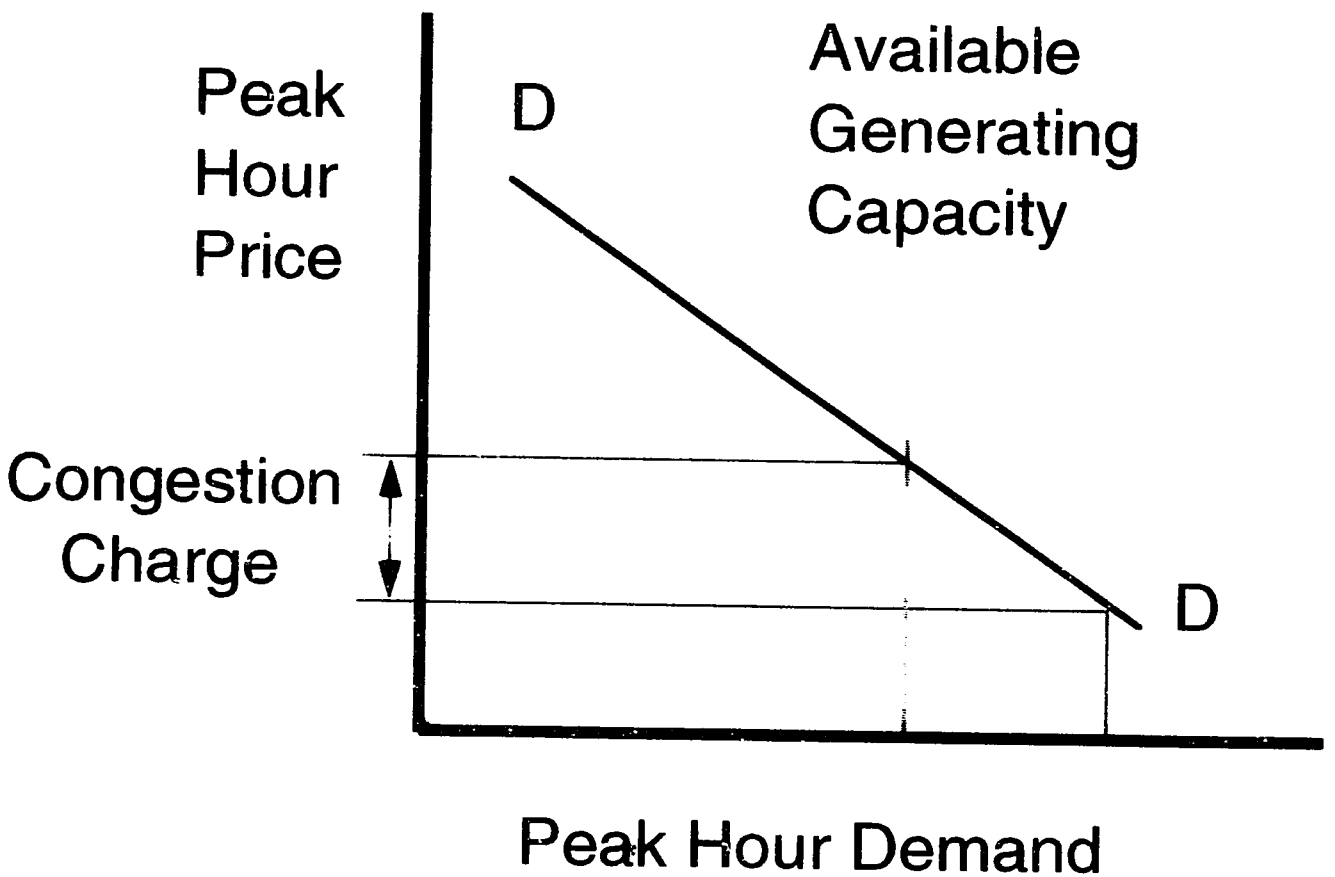
MARGINAL COST OF OUTAGE



LOST OPPORTUNITY IS MARGINAL COST

- When demand exceeds available generating capacity someone must be denied service.
- The marginal cost of the outage is equal to the unserved KWh that would have been put to the highest value.
- The highest value use is equal to the highest price that the customer would willingly pay for that KWh.

CONGESTION CHARGE NEEDED



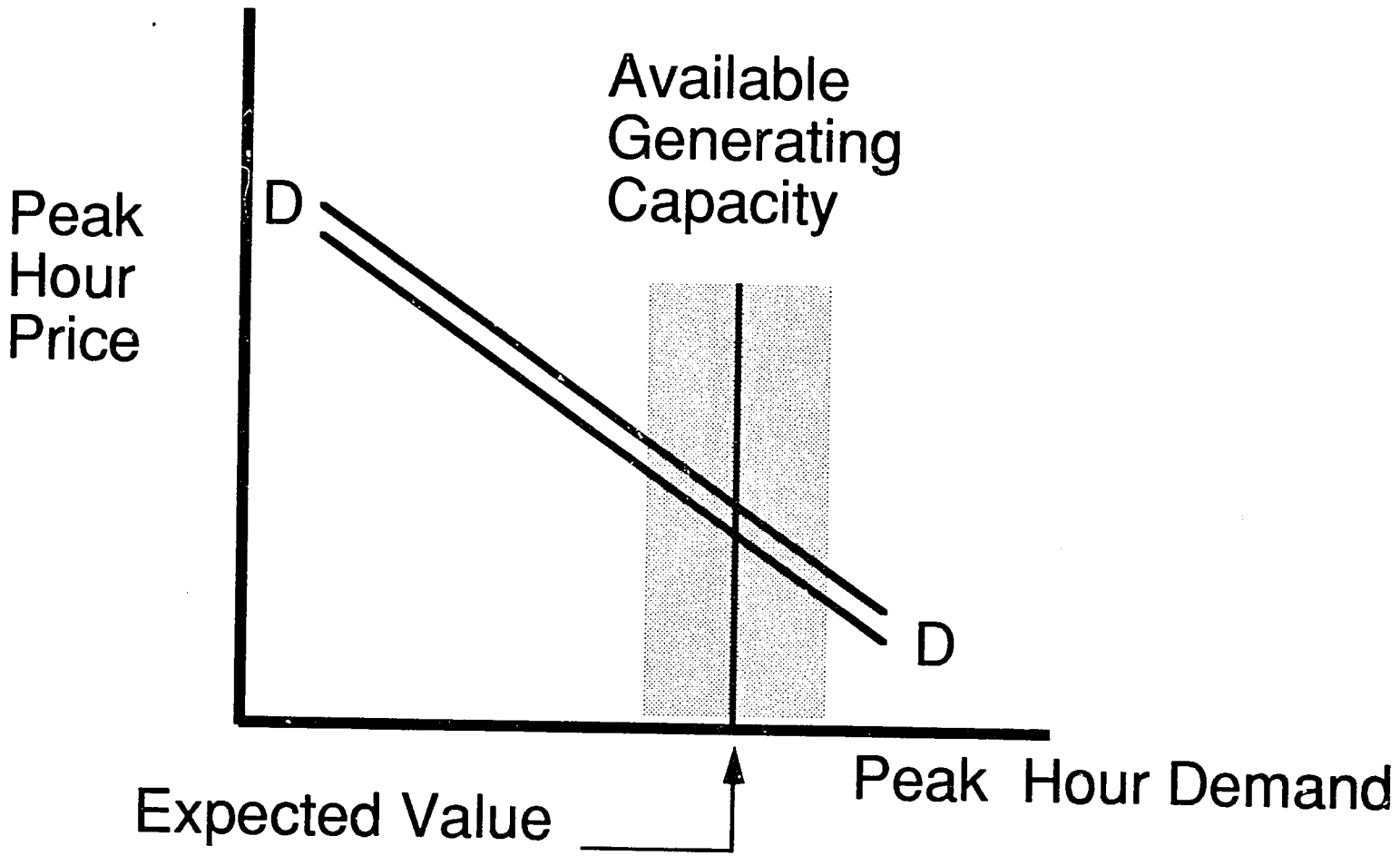
UNCERTAINTY PERVADES THE REAL WORLD

- Demand is uncertain, being determined by random events such as weather.

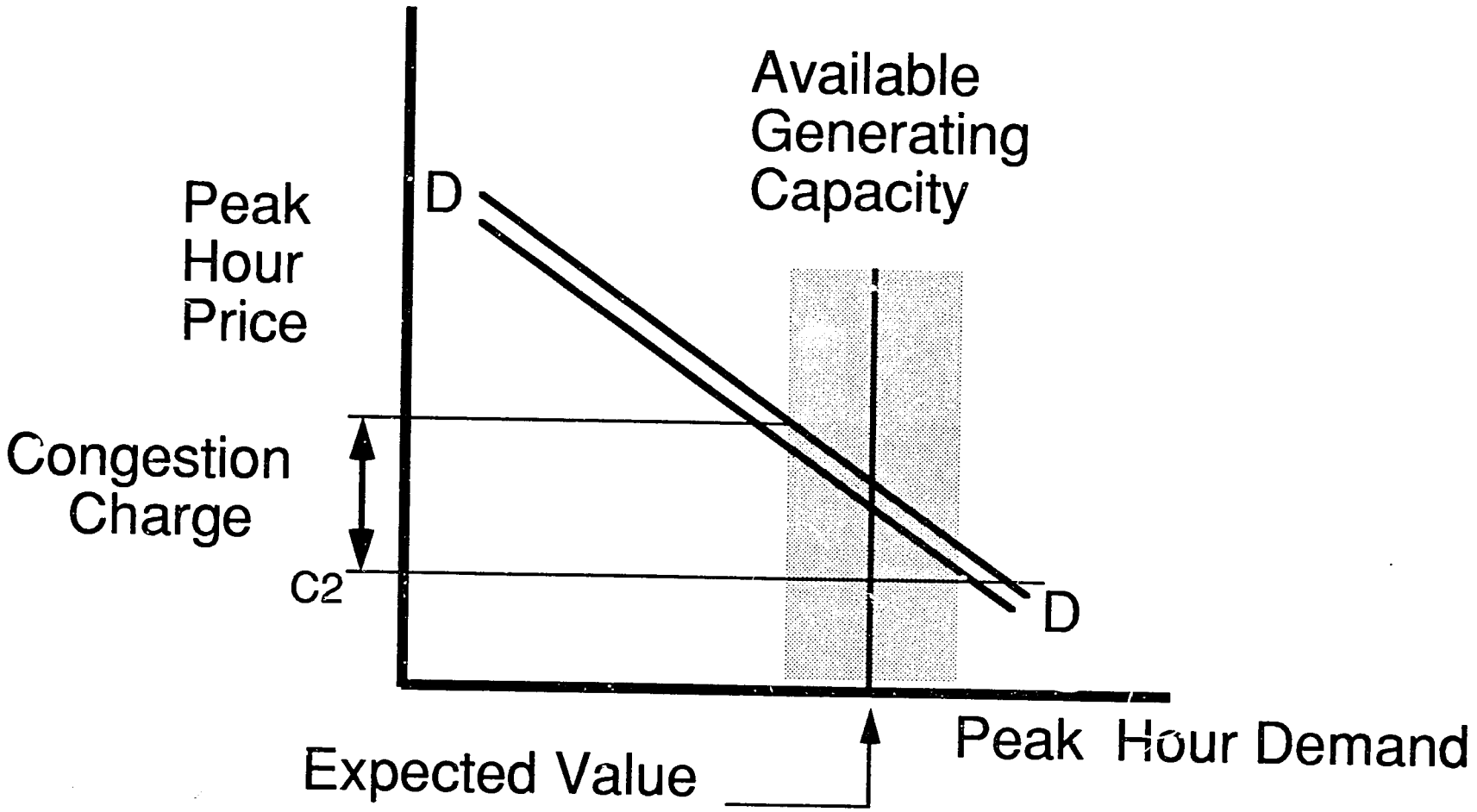
- Available generating capacity is even more uncertain because generating units break down.

- Thus, only the likelihood of an outage can be known in advance.

PROBABILISTIC SUPPLY AND DEMAND



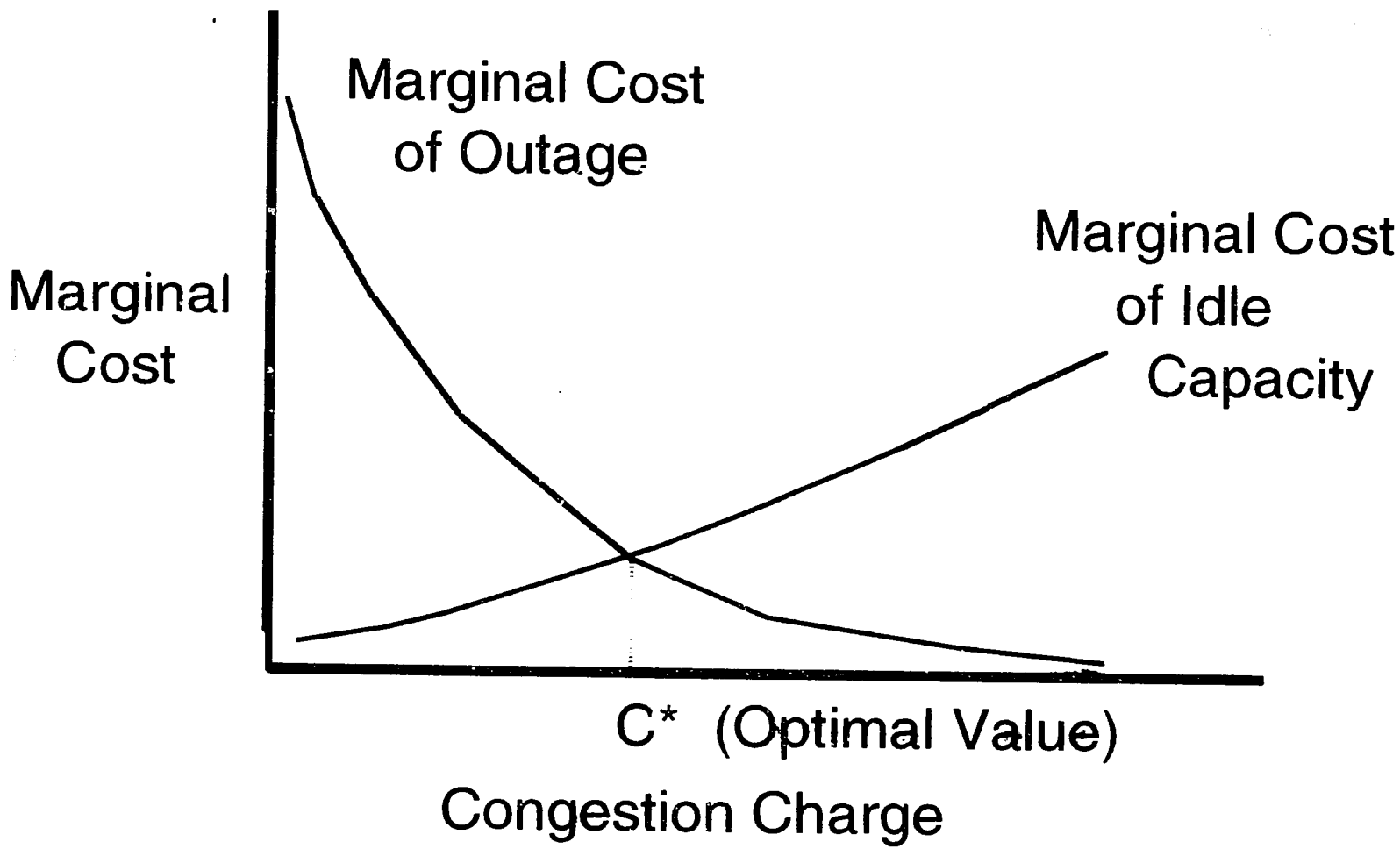
CONGESTION CHARGE STILL APPLIES



MUST BALANCE TWO COSTS

- Congestion charges cannot eliminate outages; they can only reduce the severity and frequency of occurrence.
- High congestion charges reduce outages but deny customers service when capacity is available.
- Low congestion charges make service available to more customers but allow more outages.

OPTIMAL CONGESTION CHARGE



WHEN TO ADD CAPACITY

- As electricity demand grows over time, the congestion charge will increase if capacity is not added.

- At some point the benefits from adding capacity exceed the cost of doing so.

- The congestion charge indicates when it is economic to add capacity.

CONGESTION PRICING APPLIED

- Although correct in theory, congestion pricing is difficult to apply because the costs imposed by outages are hard to quantify.

- The US and the UK apply congestion charges it in very different ways.

THE US APPROACH

- The US takes a "central planning" approach:
  - Congestion charges are set equal to the capital recovery charge of a combustion turbine.
  - The amount of new generating capacity added is controlled by the utilities serving the retail customers.

THE US APPROACH (CONTINUED)

- Electricity demand is forecasted.
- Outage probability is projected.
- Capacity is added when the probability of outage reaches a maximum acceptable level.
- Alternatively, capacity is added when the generation reserve margin reaches a minimum acceptable level.

THE (NEW) UK APPROACH

- The UK will let the free market determine when to add capacity:
  - Congestion charge is set by valuing an unserved KWh at 2£.
  - As system reliability falls the congestion charge increases.
  - Unregulated Gencos collect the congestion charge for their generation during peak hours.

WHICH APPROACH IS BEST ?

- The US approach has produced high reliability.

- But the industry also produced large capacity surpluses in the 1980s.

  - The cost of that capacity was mostly borne by utility customers.

WHICH APPROACH IS BEST (CONTINUED)

- The UK approach places the cost of excess capacity on the Gencos.
  - But that may not ensure that capacity is built when needed.
  - Severe swings in electricity prices may occur
    - Congestion charges may steeply escalate
    - then collapse to zero when too much capacity is built.

ELECTRICITY PRICING OBJECTIVES

- Encourage efficient use by consumers.
- Supply electricity at lowest cost.
- Ensure adequacy of supply.
- Promote price stability.
- Provide revenues sufficient to make the industry self-supporting.

TRANSMISSION MARGINAL COSTS

- The marginal costs of transmission systems are extremely complex.
- These costs arise because of:
  - power losses
  - network capacity constraints.
- Current state of the art is the application of optimal spot pricing theory.

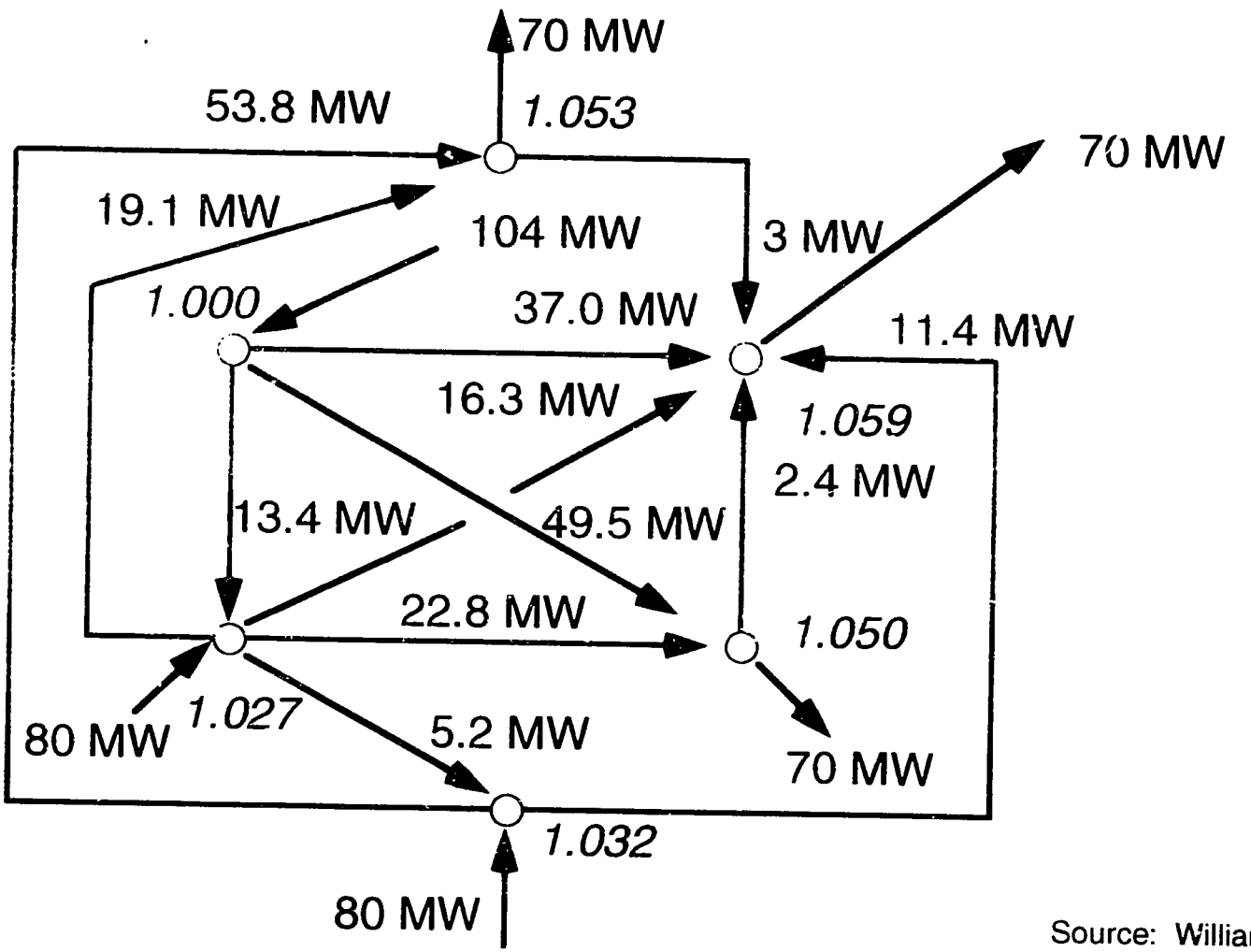
OPTIMAL SPOT PRICING

- The theory identifies the optimal prices for power at each node in a transmission network.

- Prices at interconnected nodes cannot differ by more than the marginal losses incurred in moving power between the nodes.

- Problem has been solved only for very simple systems.

EXAMPLE OF OPTIMAL SPOT PRICES



Source: William W. Hogan
Harvard University

OPTIMAL SPOT PRICING (CONTINUED)

- But research into optimal spot pricing for transmission continues.
  - the Australians are currently experimenting with it.
- With further development, it could provide Gencos with information on the best locations for new generating plants.

CONVENTIONAL PRICING

- The conventional approach is to treat all transmission costs as fixed in the short run, thus are not marginal.

- However, transmission losses are variable, and do contribute to marginal costs.

CONVENTIONAL PRICING (CONTINUED)

- An energy (per KWh) surcharge is designed to:
  - cover power losses,
  - recover operating costs
  - recover the sunk capital costs
  - provide funds for future expansion.
- Similar to a "long-run" marginal cost approach.

CONVENTIONAL PRICING (CONTINUED)

- Transmission surcharges may be applied as:
  - single, system-wide "postage stamp" rates, or
  - area-specific rates.

- Load flow studies revealing transmission bottlenecks and losses can provide a basis for area-specific pricing.

CONVENTIONAL PRICING (CONTINUED)

- Conventional Approach is crude and basically wrong.

- But it is easy to apply.

- Fortunately, for most power systems generation costs are much greater than transmission (or distribution) costs.

PRICE REGULATION MAY BE NEEDED

- A transmission system is a natural monopoly; it has no competition.
- Price regulation may be required to preclude Transco (PSENN) from exploiting its monopoly power.
- This is true even if Transco (PSENN) is government-owned.
  - pricing guidelines can prevent selective taxation of consumers.

REGULATING TRANSMISSION PRICES

- In the UK transmission prices are allowed to increase by an amount equal to RPI-X.
  - RPI is the Retail Price Index, a measure of general inflation
  - x is a productivity factor.
- The UK regulation is superior to US regulation because it provides greater incentives for efficiency.

ELECTRICITY PRICING OBJECTIVES

- Encourage efficient use by consumers.
- Supply electricity at lowest cost.
- Ensure adequacy of supply.
- Promote price stability.
- Provide revenues sufficient to make the industry self-supporting.

ROLE OF DISTCOS

- Distribution companies (Distcos) provide two separable services:
  - they supply (resell) electricity to customers
  - they provide distribution network services.
- In the UK the supply service can be provided by a non-distribution company; in the US it cannot.

DISTRIBUTION MARGINAL COSTS

- As with Transmission, the marginal costs of distribution systems are complex.
  - But loop flow is less of a problem.
  - Line losses are more important
  - And many costs are traceable to specific customer classes.

COSTS BY VOLTAGE LEVEL

- Distribution costs vary by voltage level:
  - Higher losses occur at the lower voltages provided to small customers.
  - Also more investment is required per KWh delivered.

WHAT COSTS ARE MARGINAL?

- Distribution losses are variable, thus contribute to marginal costs.
- Much distribution investment is for equipment required to provide access.
  - These costs are fixed and do contribute to marginal costs.
- Some "Upstream" distribution costs are marginal but difficult to quantify.

DESIGNING RETAIL PRICES

- Retail tariffs are designed to recover all costs of serving the customer:
  - generation costs
  - transmission costs
  - distribution costs
  - supply costs.
- These costs include both marginal costs and fixed costs.

DESIGNING RETAIL PRICES (CONTINUED)

- Ideally, fixed costs are recovered through monthly or quarterly standing charges.
- Marginal costs are recovered through prices applied to customer's maximum KW demand and KWh usage.
- To the extent practical, prices should vary with time of use.

TIME-OF-USE METERING IS DESIRED

- To vary prices by time of day, metering of hourly usage is required.
  - Should be done for large commercial and industrial customers.
  - Usually not cost-effective for residential and other small customers.

- But prices for small customers should be varied by season of the year.

TARIFF DESIGN IS AN ART

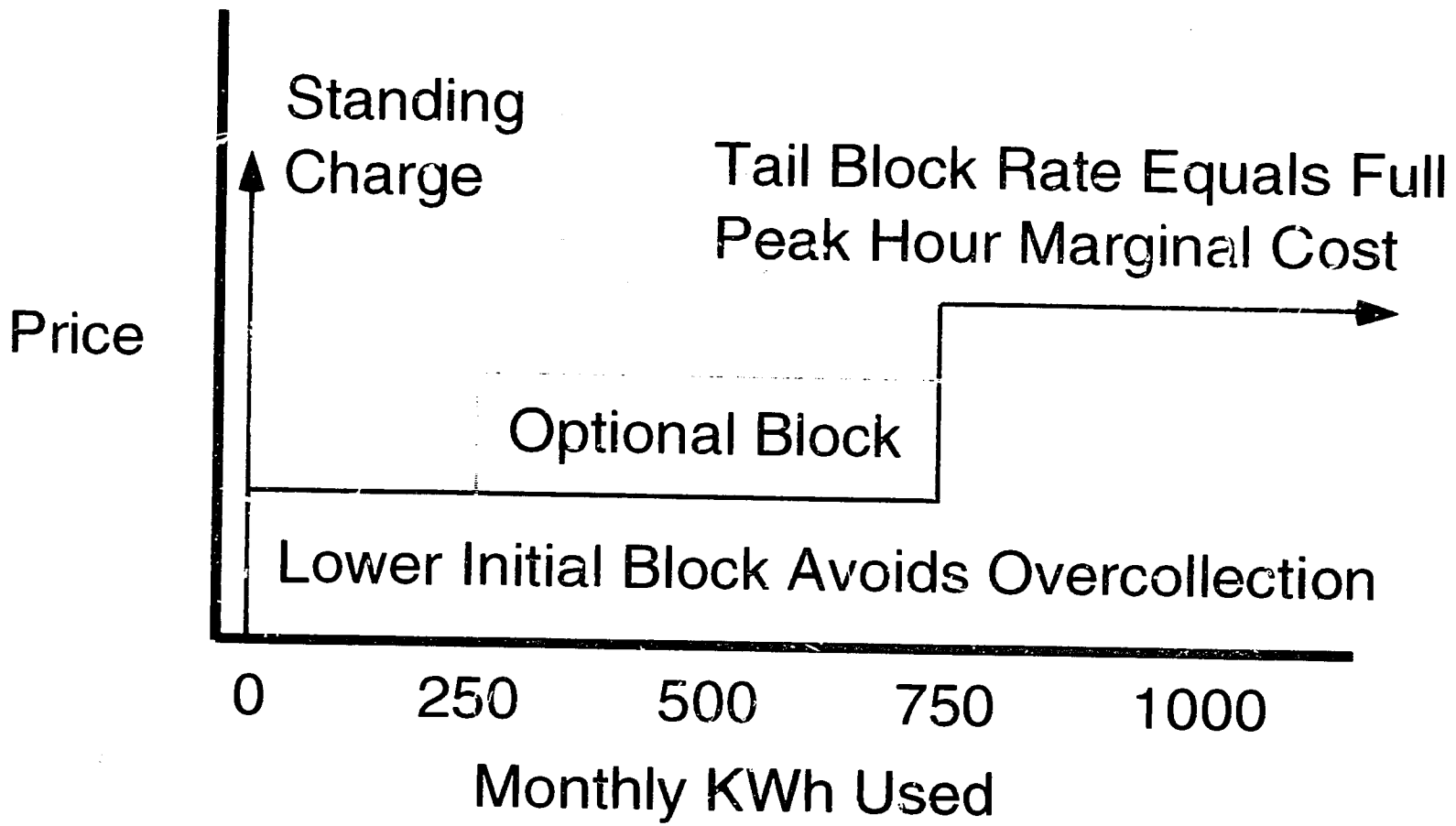
- Small customer tariffs usually involve compromises.
  - Typically some fixed costs may have to be recovered through energy prices.
  - Also, peak hour marginal costs may have to be recovered from non-peak usage.
- In such cases the "inverse elasticity" rule should be applied.

THE INVERSE ELASTICITY RULE

- The "Inverse elasticity" rule:
  - If some prices must deviate from marginal costs, those applied to the least elastic demands should deviate the most.

- Economic efficiency is only affected by pricing when the demand to which it is applied is elastic, i.e., where the customer has a choice

EXAMPLE OF A RESIDENTIAL TARIFF



NEED FOR PRICE REGULATION

- As with transmission, distribution systems are natural monopolies.
- They need to be price regulated to prevent exploitation of monopoly power.
- This is true even if a Distco is government-owned because electricity prices can be used to selectively tax consumers.

PRICING OBJECTIVES REVISITED - I

- Efficient use of electricity is encouraged if marginal generation costs are passed through Transco and the Distcos to retail customers.

- Retail customers should also be charged the marginal costs transmission and distribution costs they impose on the power system.

- To the extent possible, this means time-of-use pricing.

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PRICING OBJECTIVES REVISITED - II

- Least-cost production results from paying Gencos prices equal to the system's marginal cost of generation because:
  - it makes efficient operation profitable for each Genco.
  - it makes least-cost construction of new capacity profitable.
  - it supports economic dispatch.

PRICING OBJECTIVES REVISITED - III

- Paying Gencos prices equal to the marginal cost of generation will ensure adequacy of supply.

- But only if congestion charges are set high enough to make investments in new capacity profitable.

PRICING OBJECTIVES REVISITED - IV

- Relying on pricing alone to ensure supply adequacy may promote price instability.

- This classic boom-bust cycle is apparent in other capital intensive market-driven industries.

- Some form of capacity planning coordination may be desirable.

PRICING OBJECTIVES REVISITED - V

Paying Gencos prices equal to the marginal cost of generation will ensure their self-sufficiency.

- Most will cover their operating costs, because marginal costs will generally exceed average costs.

- Still, some inefficient, high cost Gencos may earn low returns on invested capital.

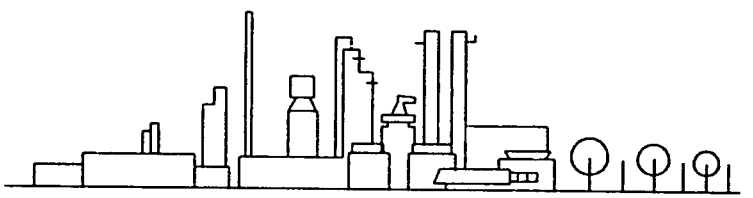
REGULATING DISTRIBUTION PRICES

- In the UK distribution prices are allowed to increase by an amount equal to RPI-X.
  - RPI is the Retail Price Index, a measure of general inflation
  - x is a productivity factor.
- The UK regulation is superior to US regulation because it provides greater incentives for efficiency.

POLAND ENERGY PRICING SEMINAR

PETROLEUM PRICES – AN OVERVIEW

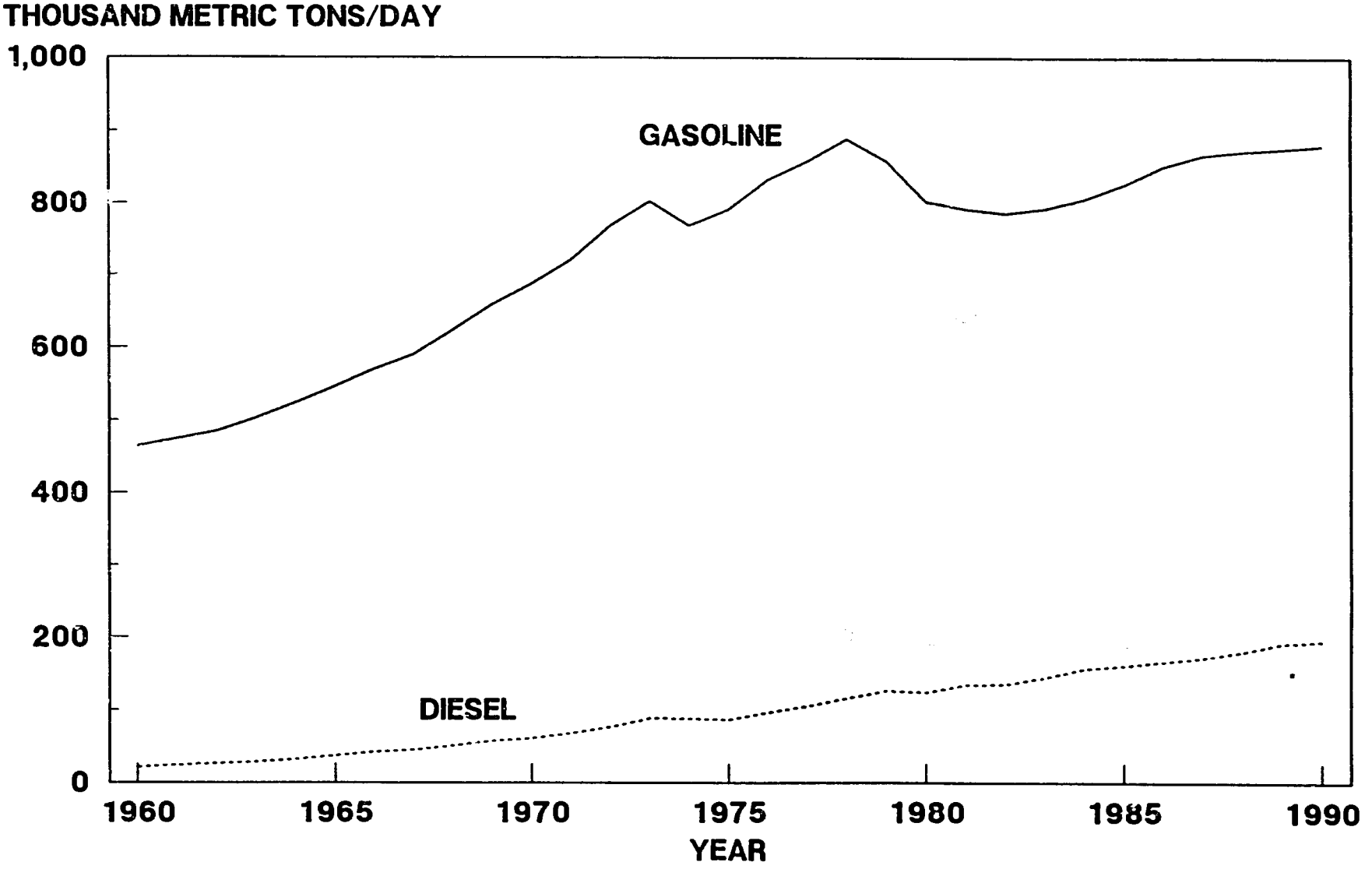
Presented by B. Dutkiewicz



WARSAW

4 September, 1991

GASOLINE AND DIESEL CONSUMPTION
HIGHWAY MOTOR VEHICLES



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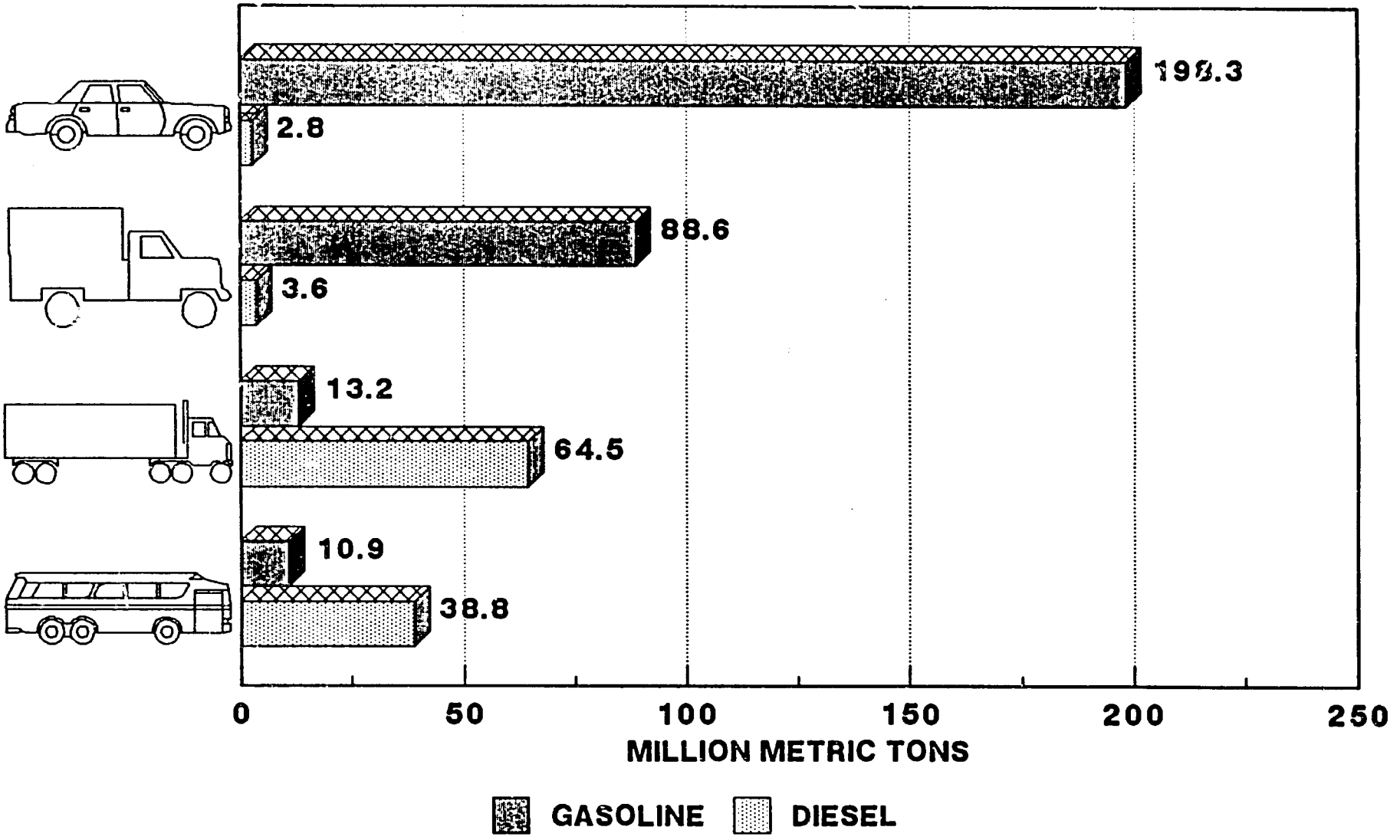
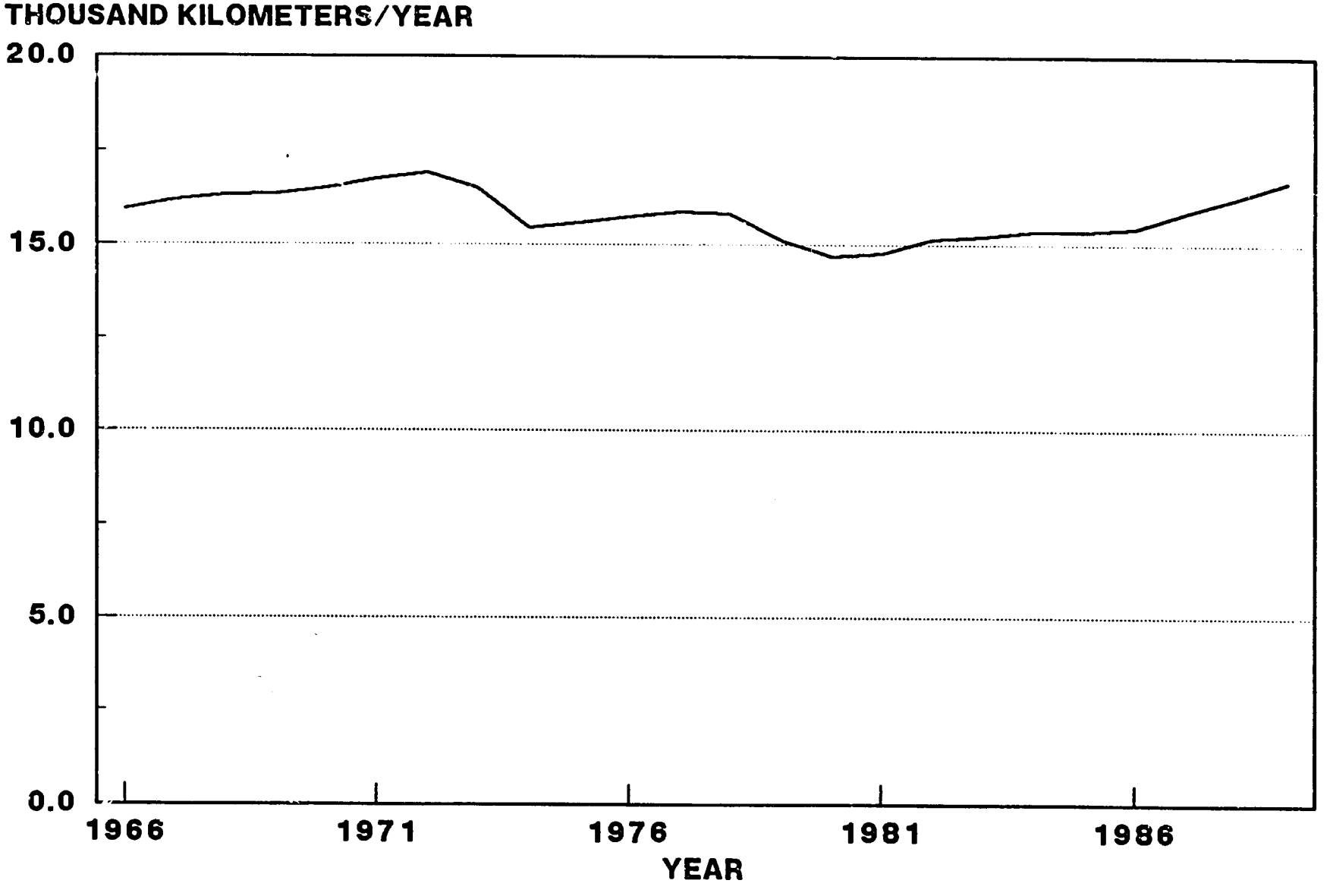
U.S. TRANSPORTATION FUEL CONSUMPTION

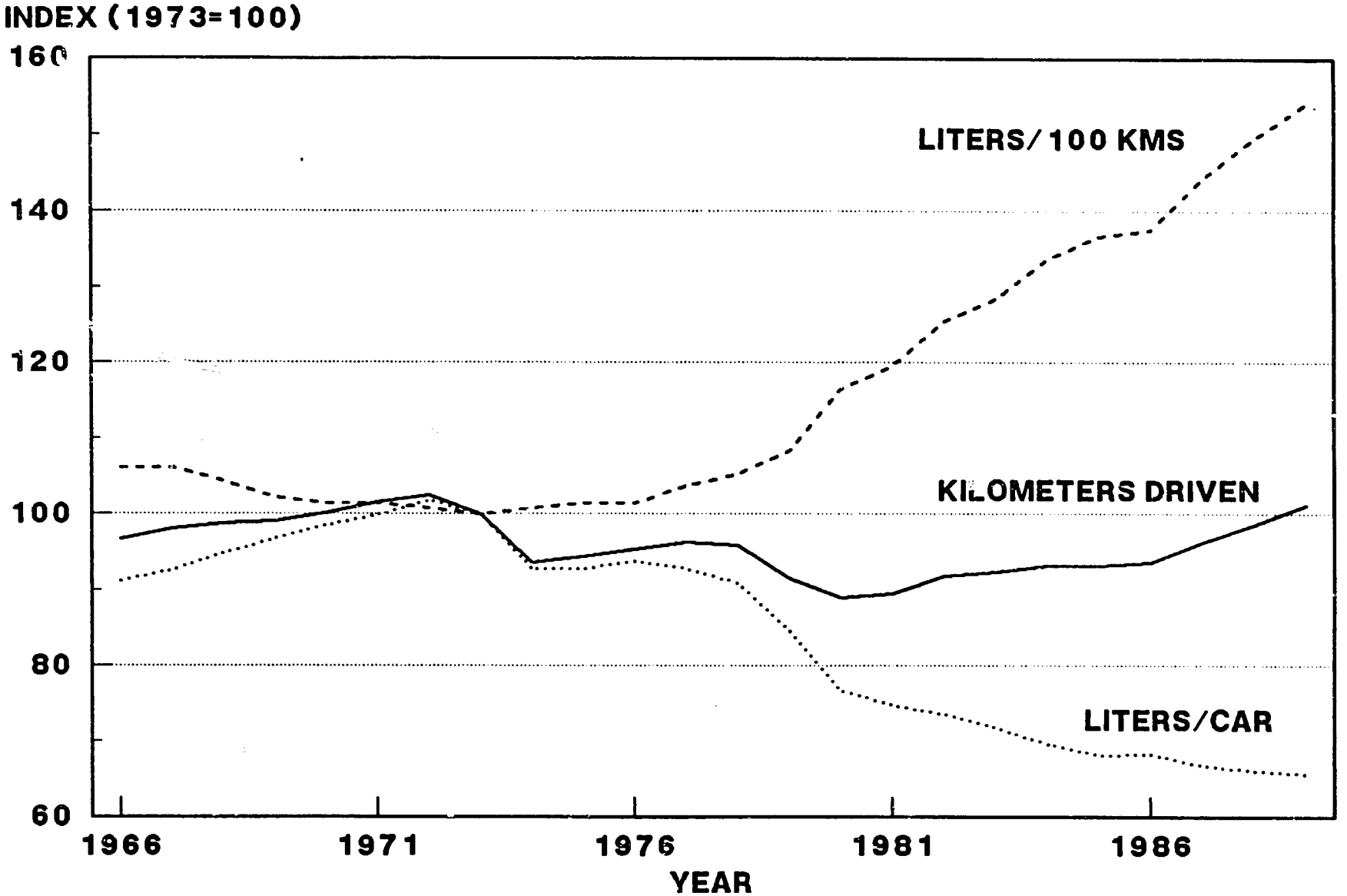
BY TYPE OF VEHICLE, 1988



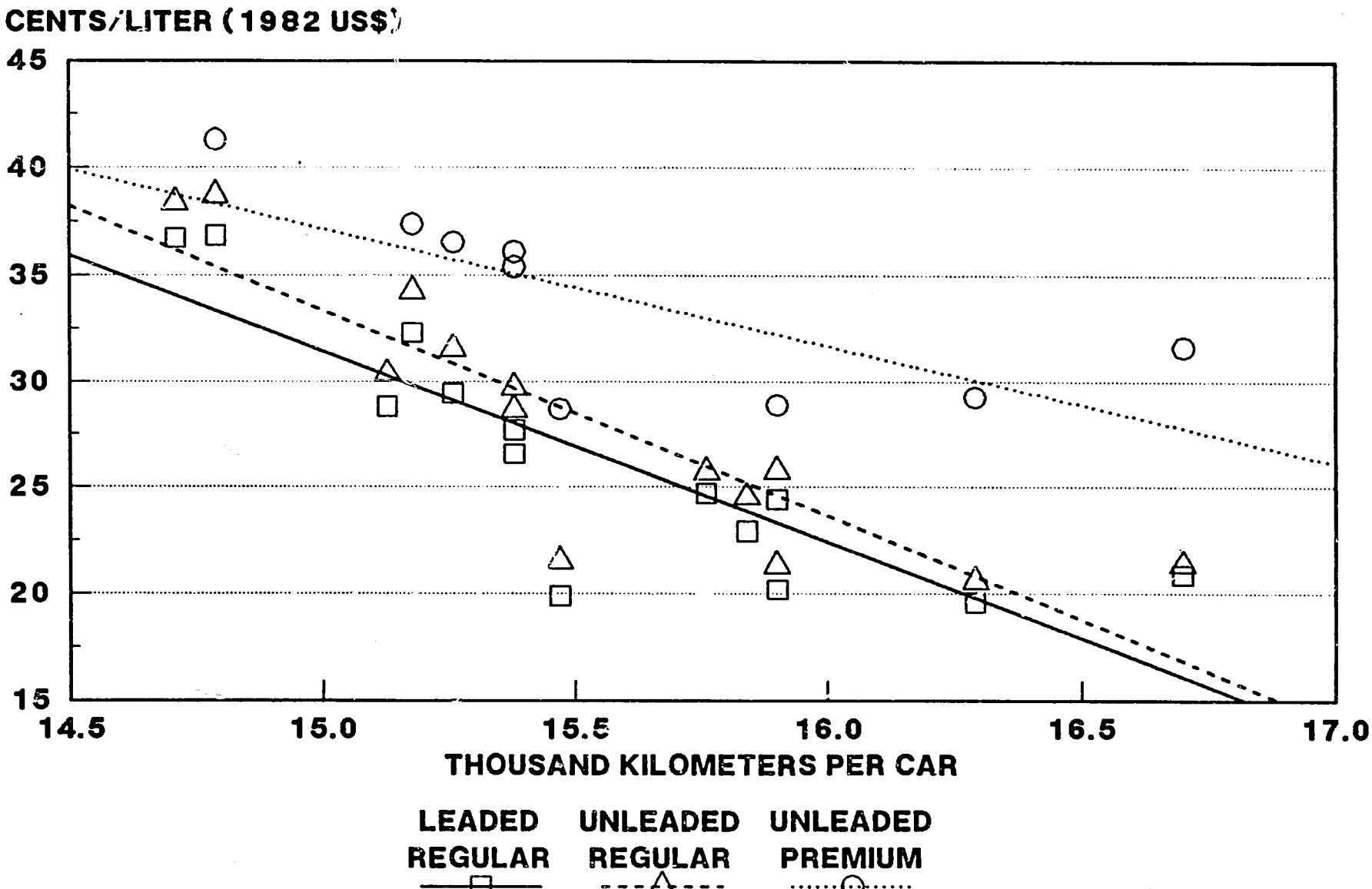
PASSENGER VEHICLE USAGE



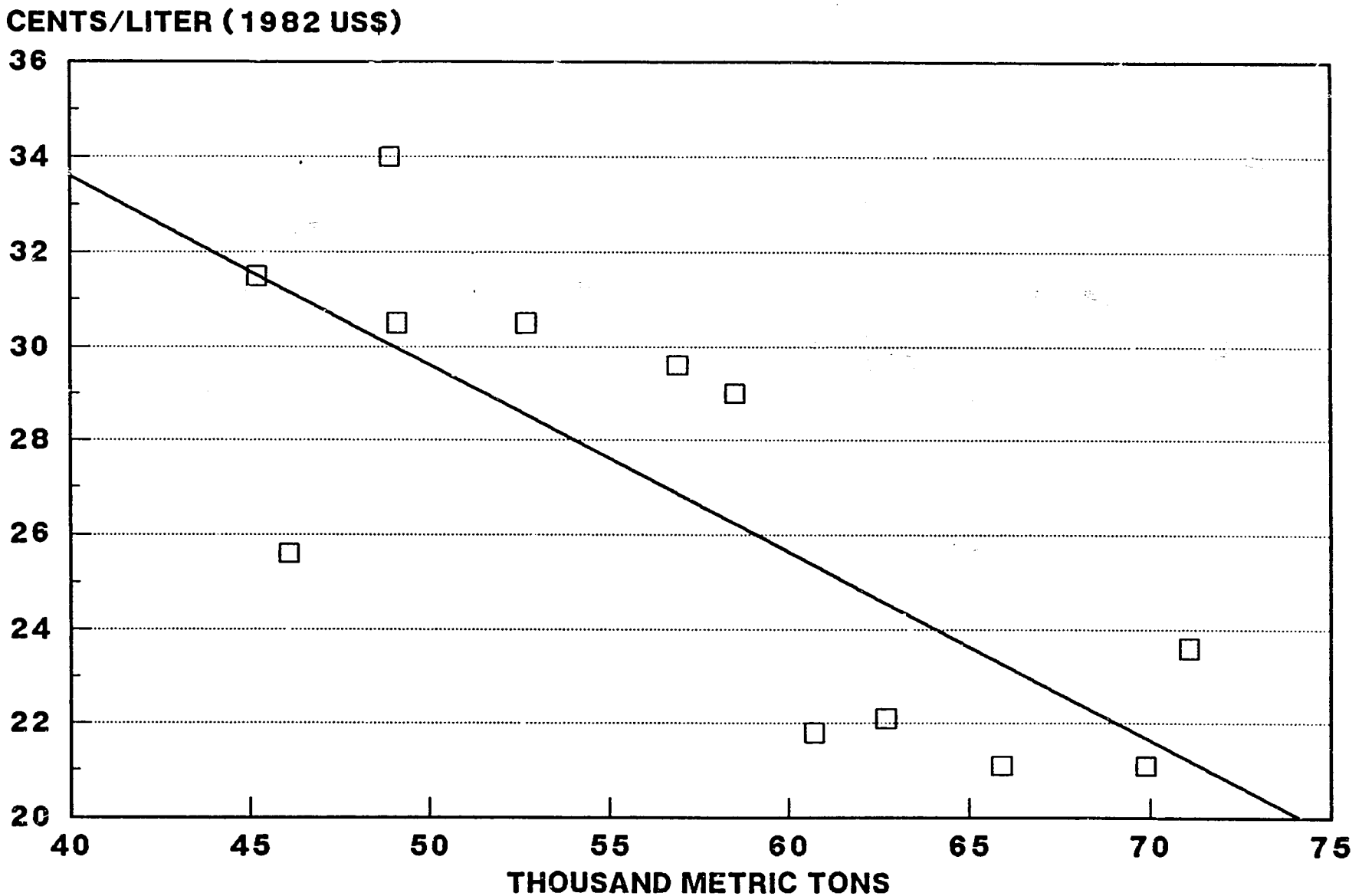
PASSENGER CAR EFFICIENCY



PRICE ELASTICITY* OF GASOLINE

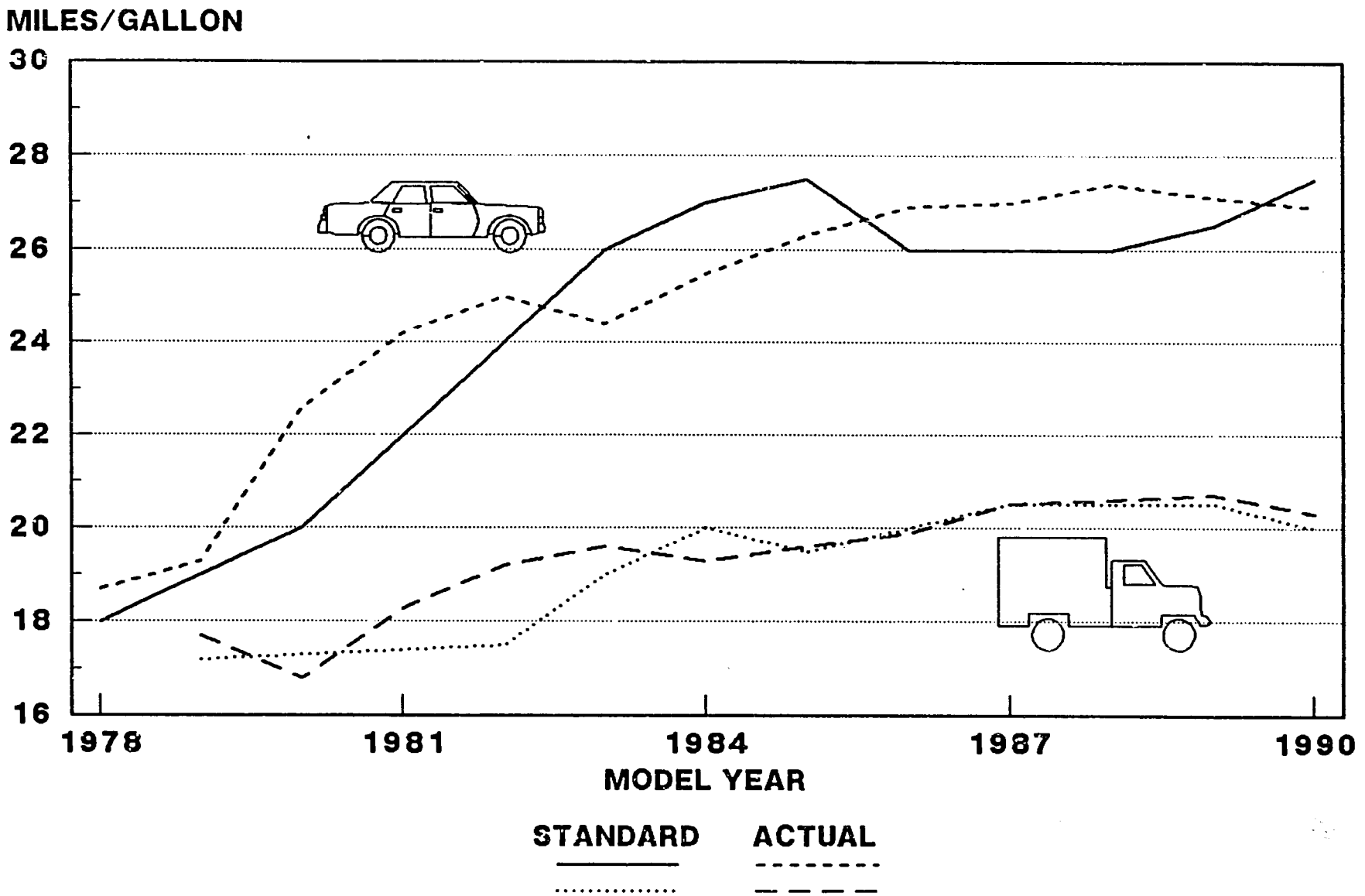


PRICE ELASTICITY* OF DIESEL



CORPORATE AVERAGE FUEL ECONOMY (CAFE) STANDARDS

AUTOMOBILES AND LIGHT TRUCKS



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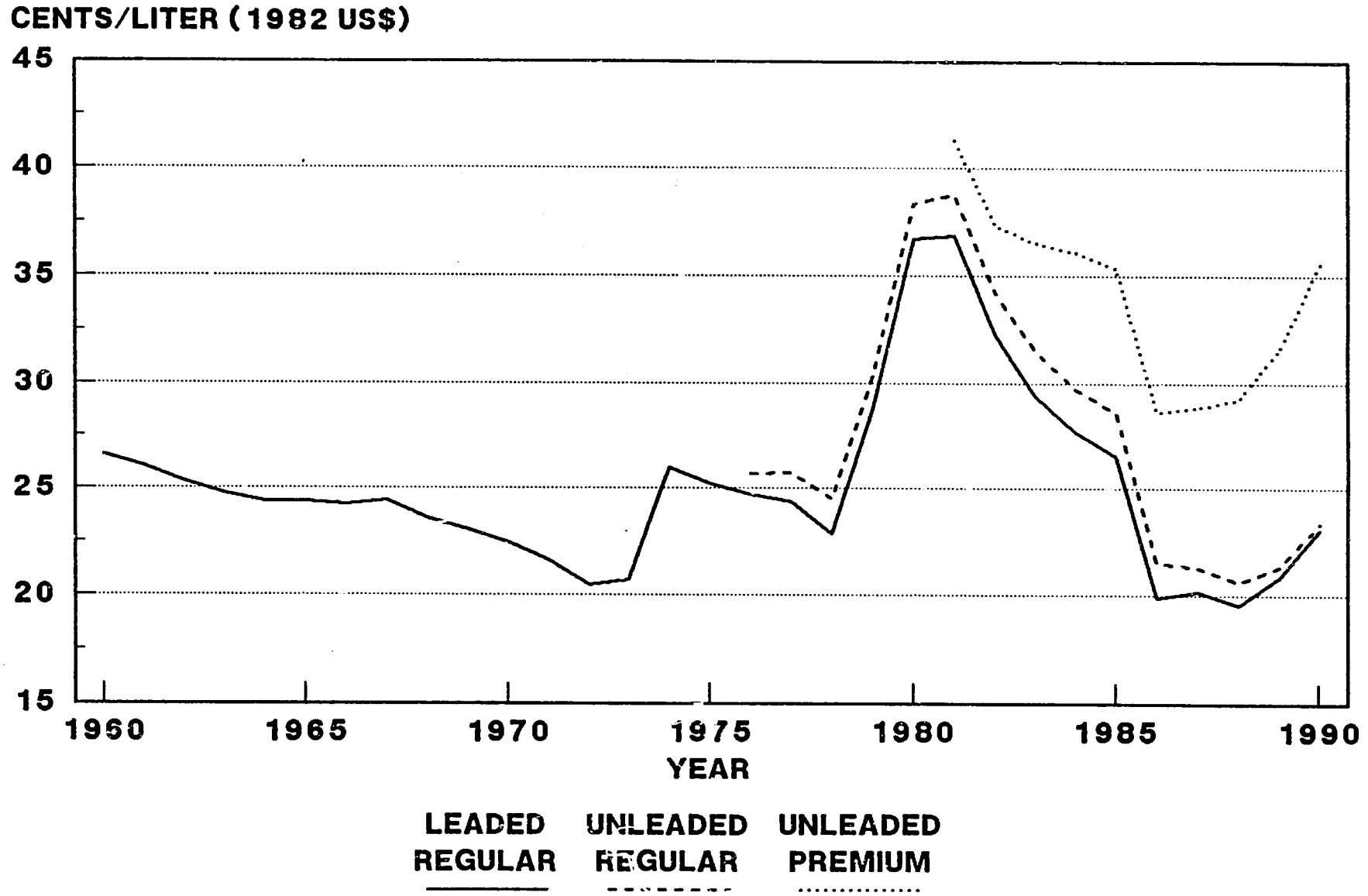
REAL PRICE OF GASOLINE



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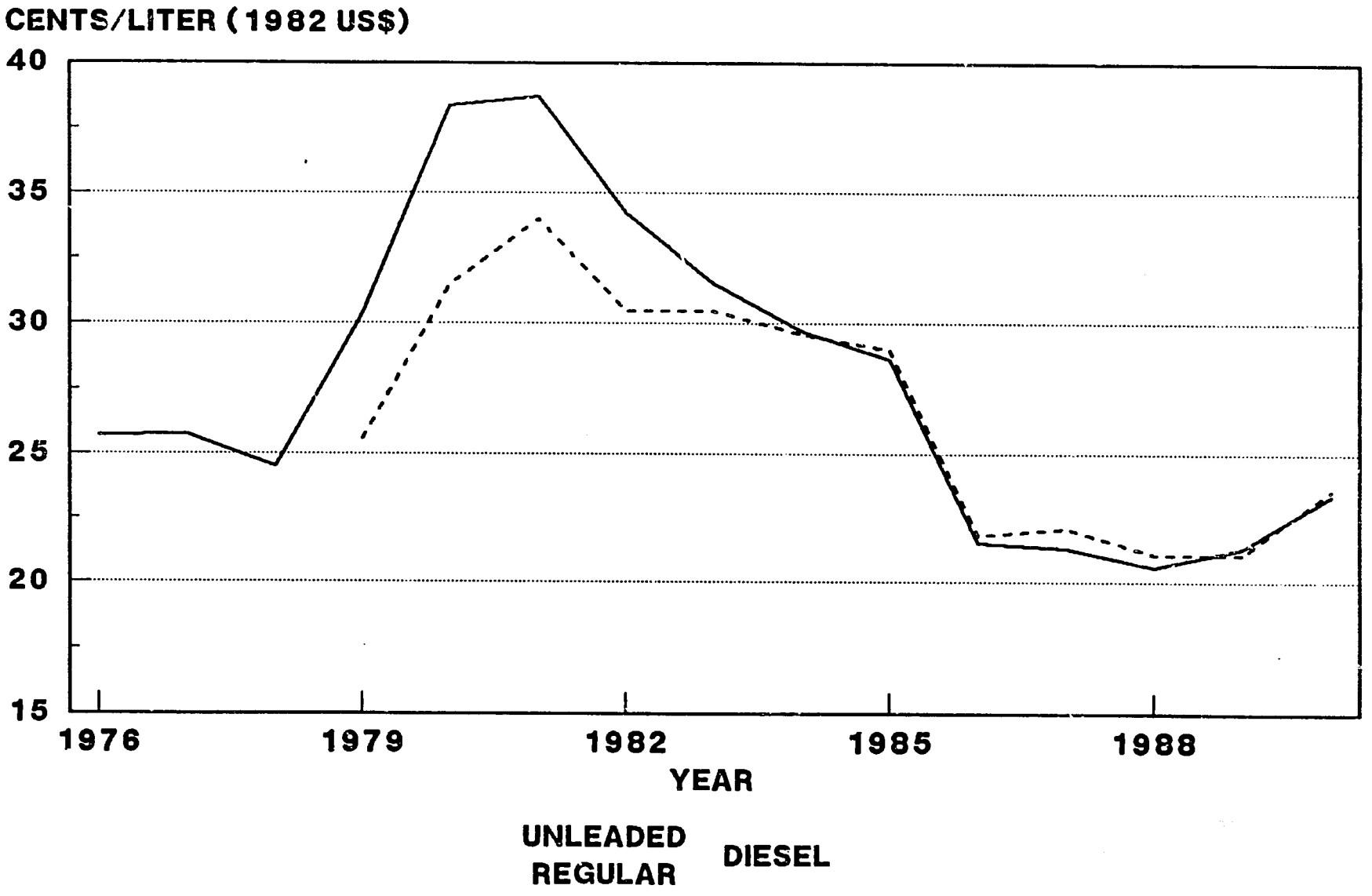
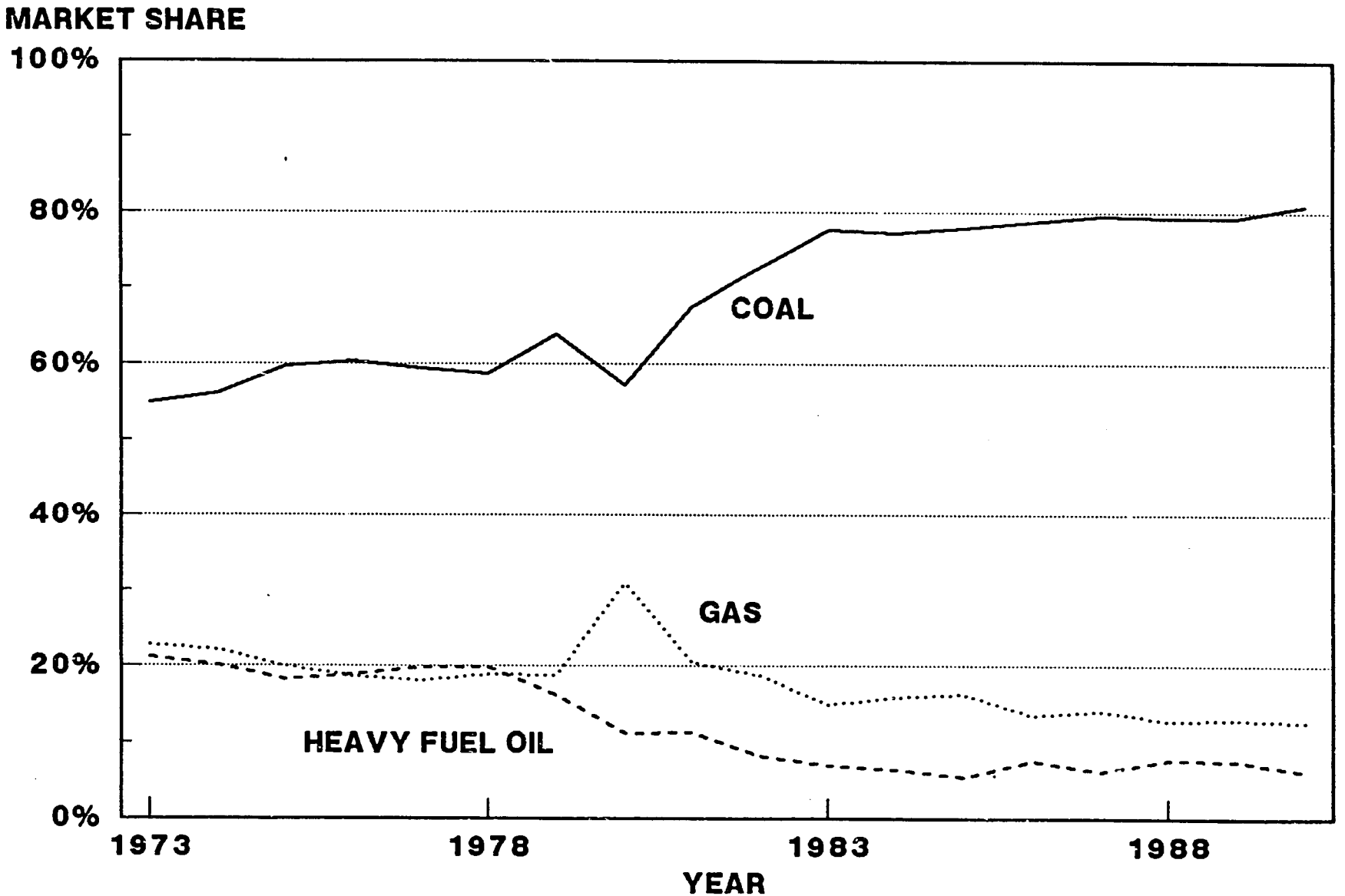
REAL PRICE OF GASOLINE AND DIESEL



FUELS FOR ELECTRIC POWER



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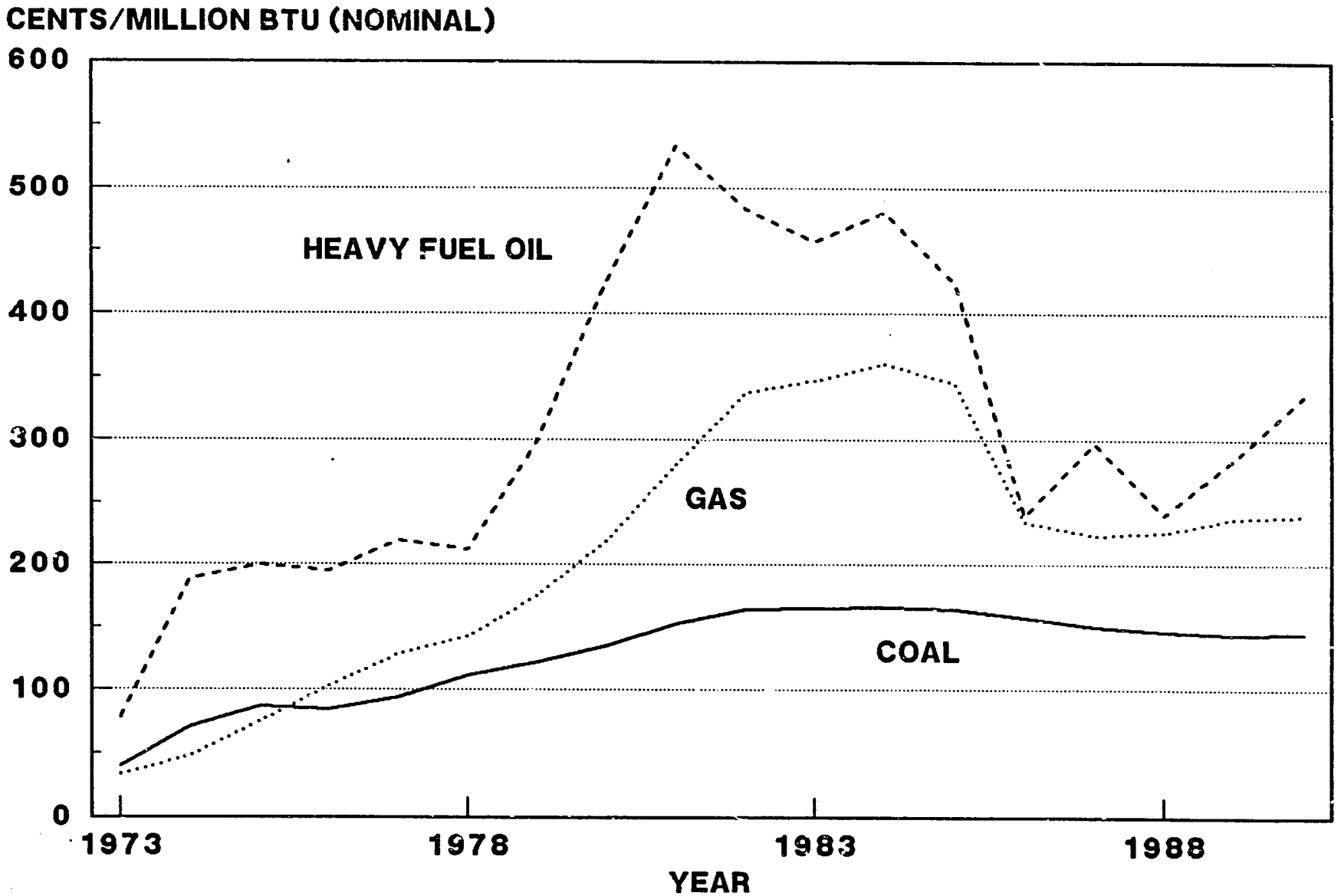
POWER STATION FUEL COSTS



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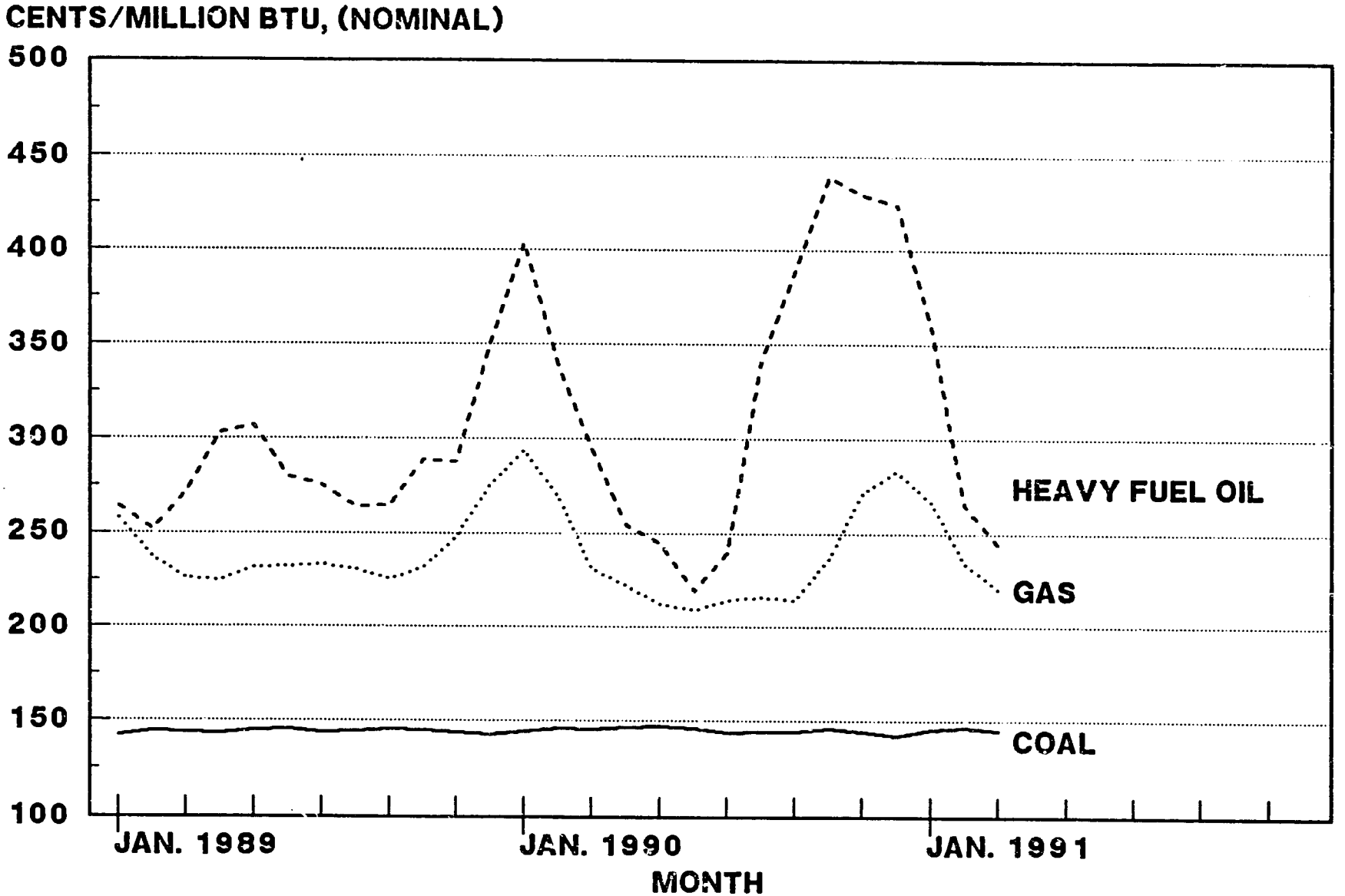
POWER STATION FUEL COSTS



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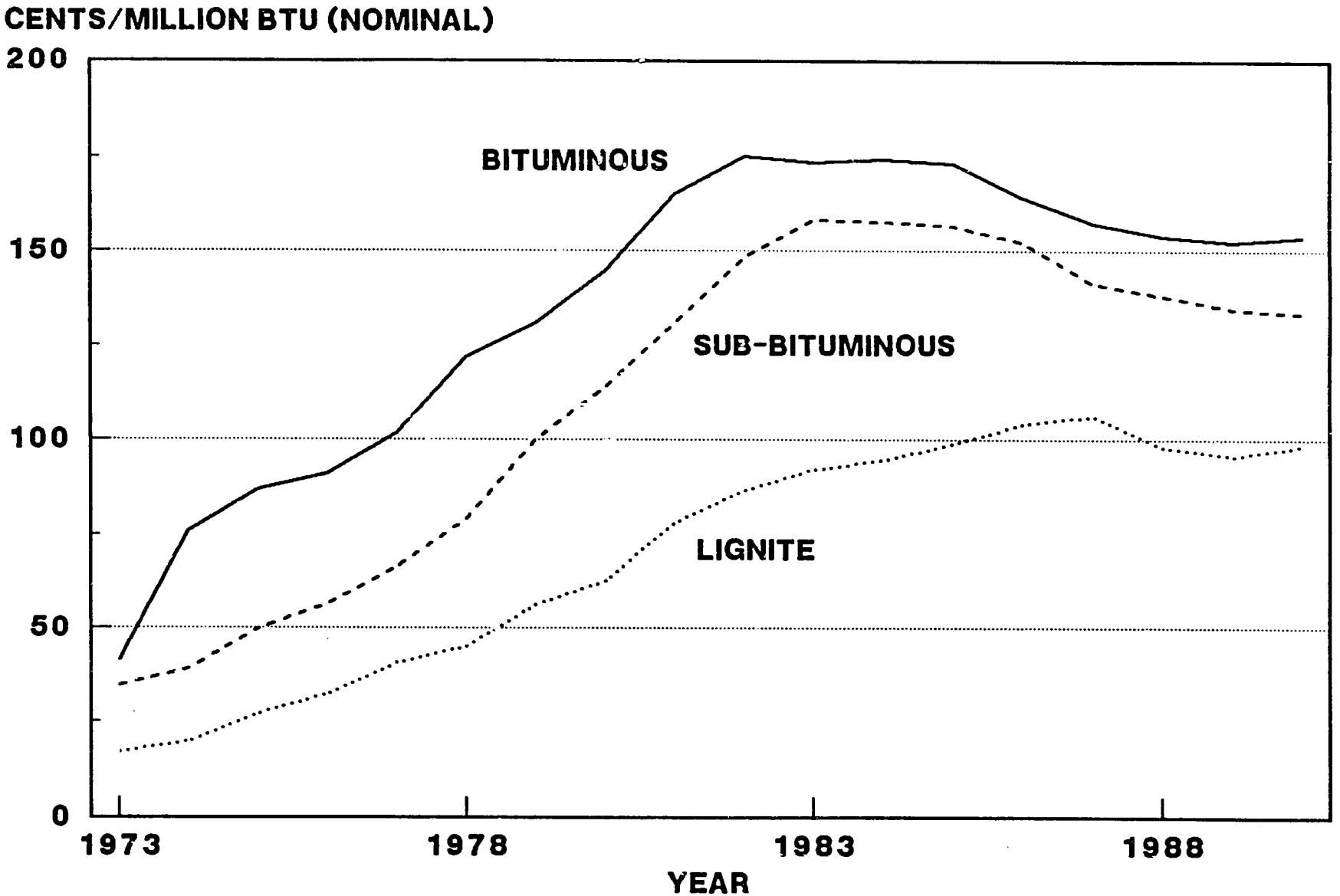
COST OF COAL FOR POWER GENERATION



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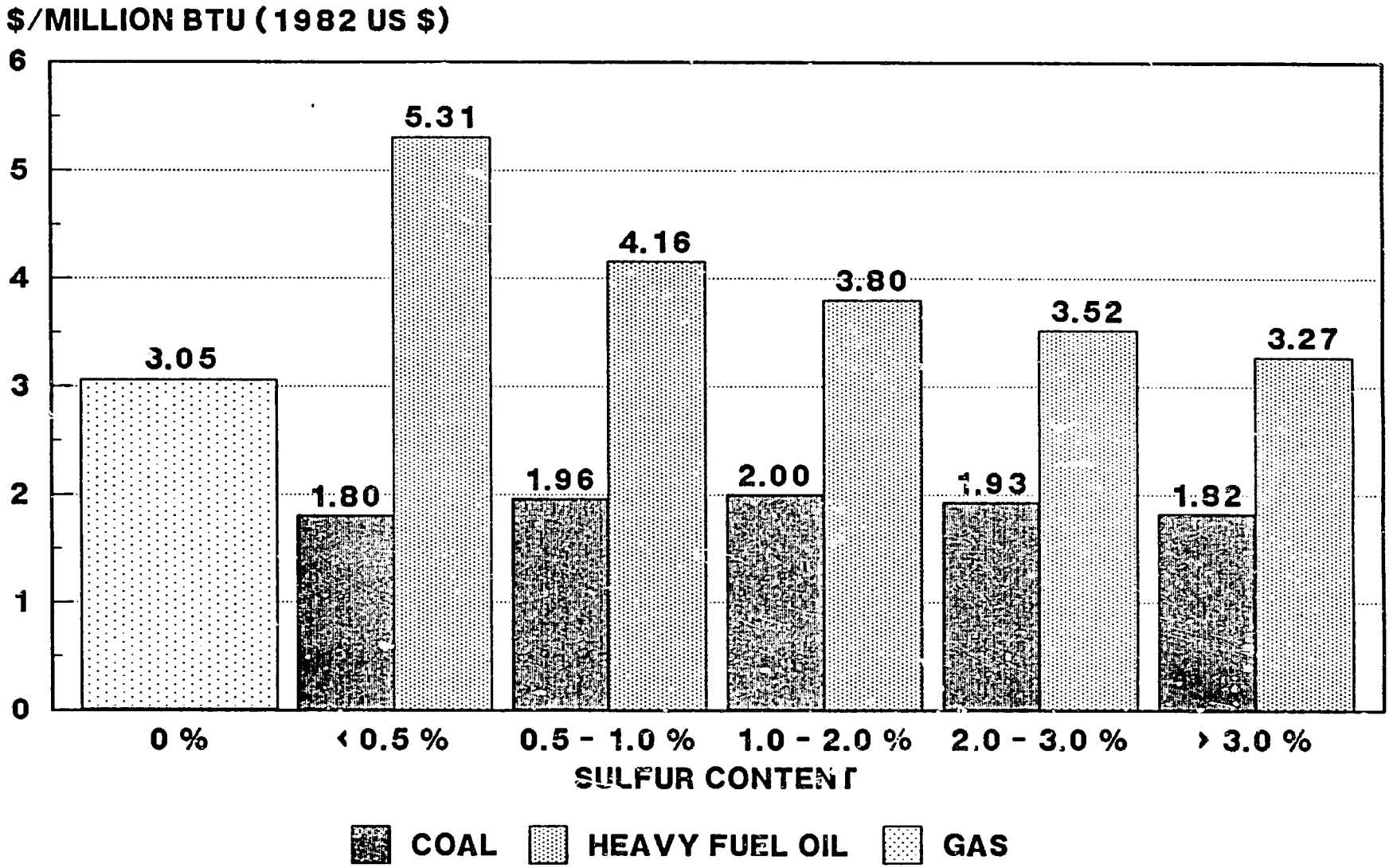
POWER STATION FUEL PRICE

BY SULFUR CONTENT



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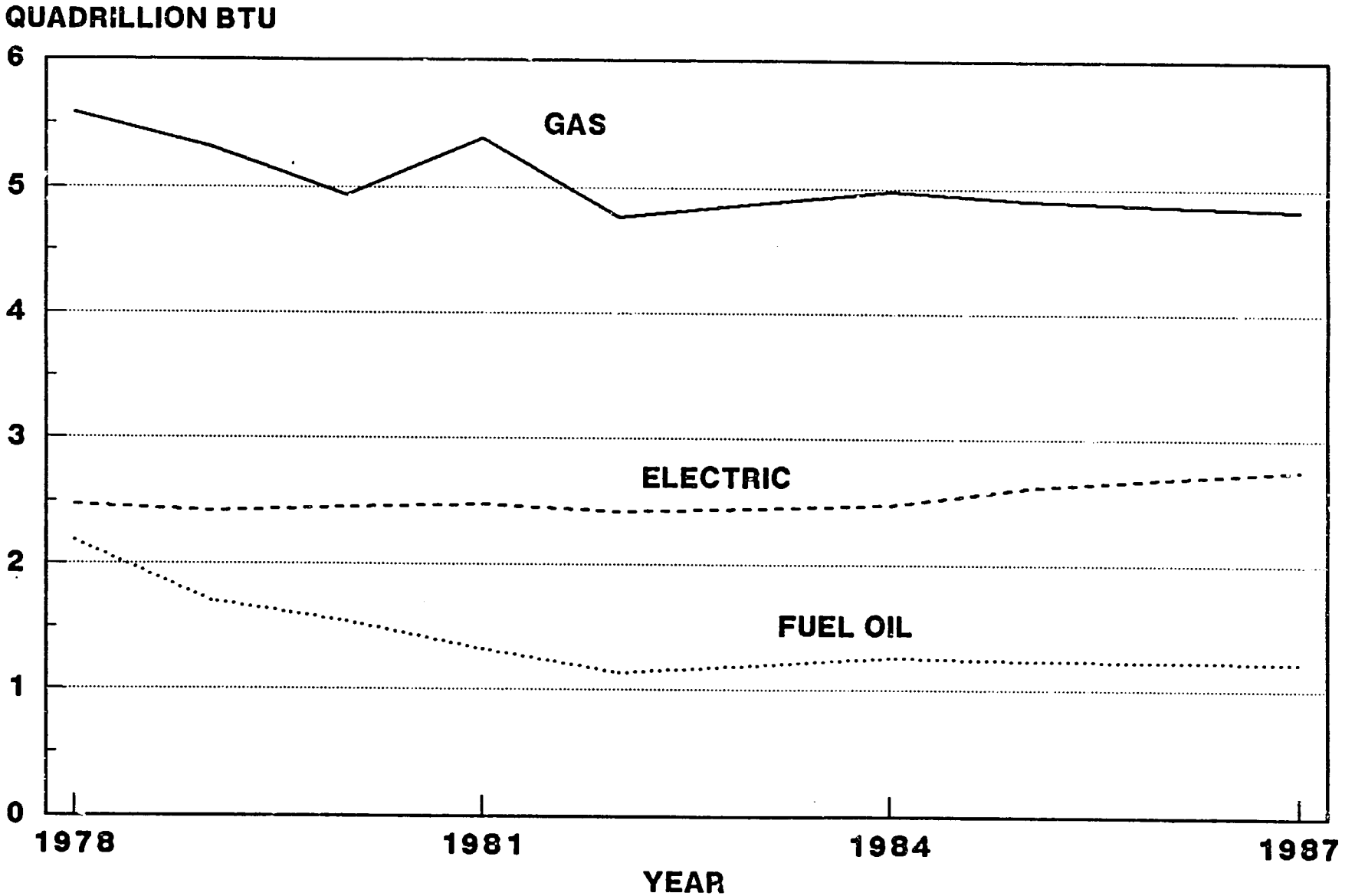
HOUSEHOLD ENERGY CONSUMPTION



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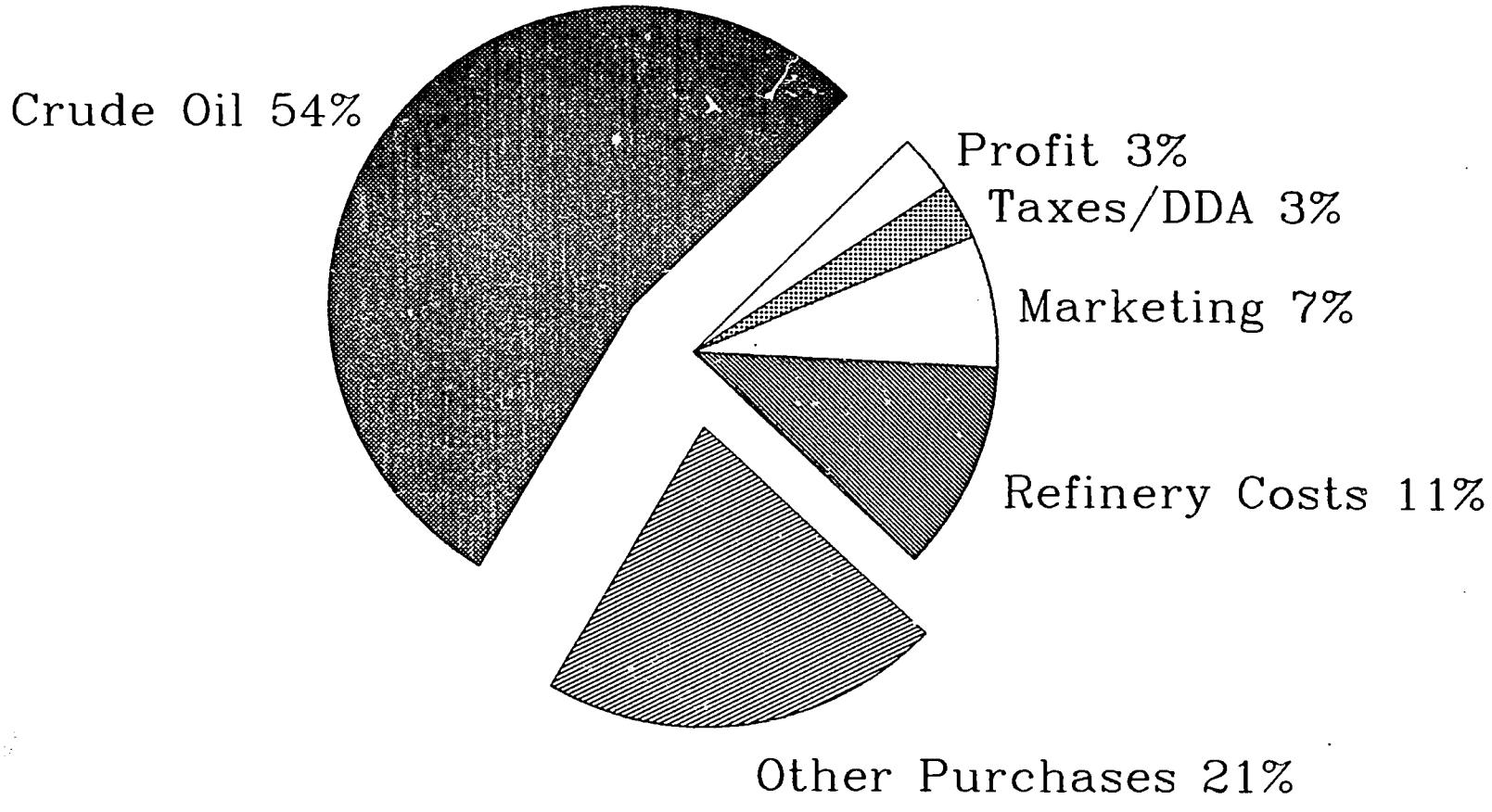
Crude Oil Prices

Petroleum Product Prices
US 1989



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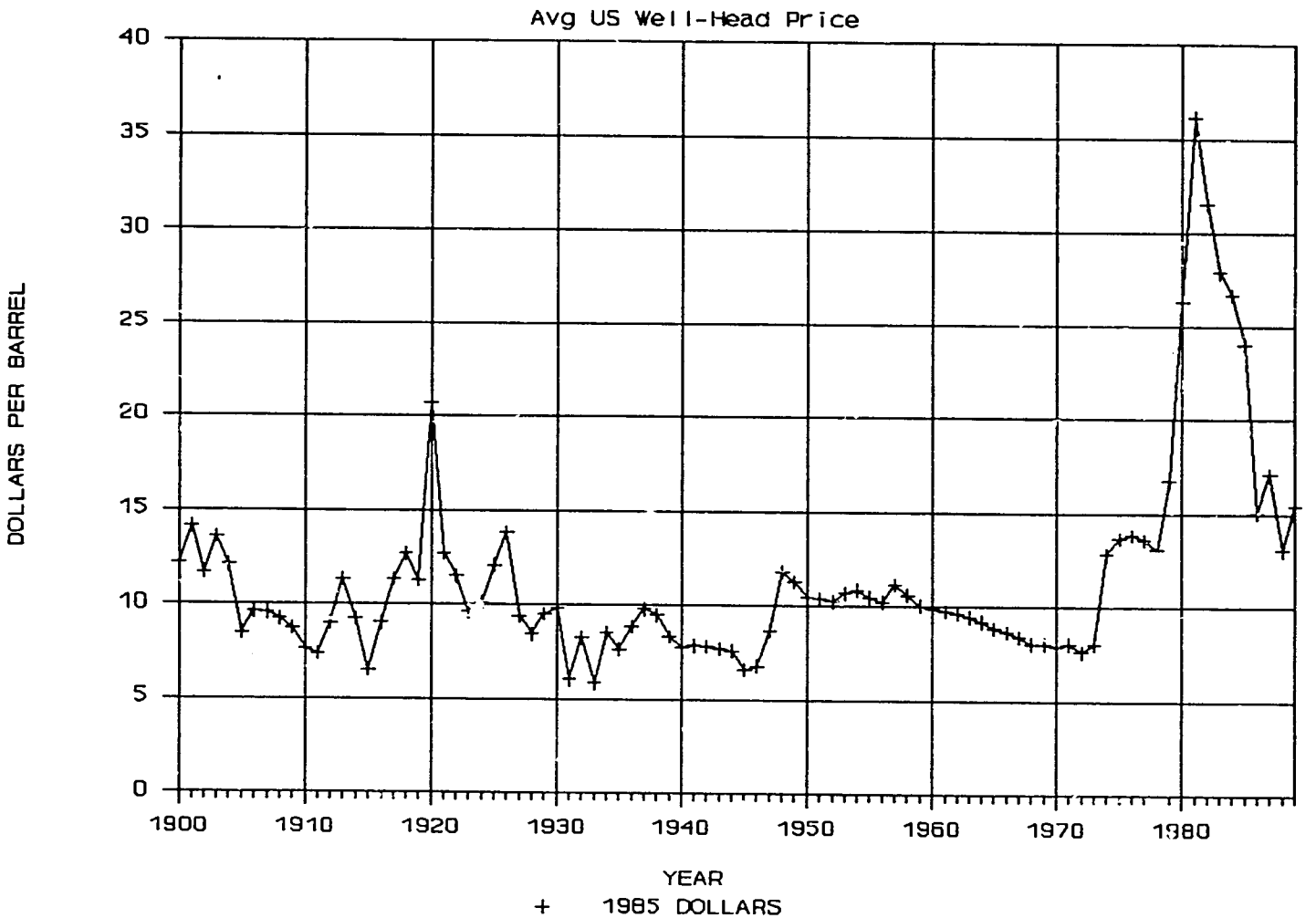
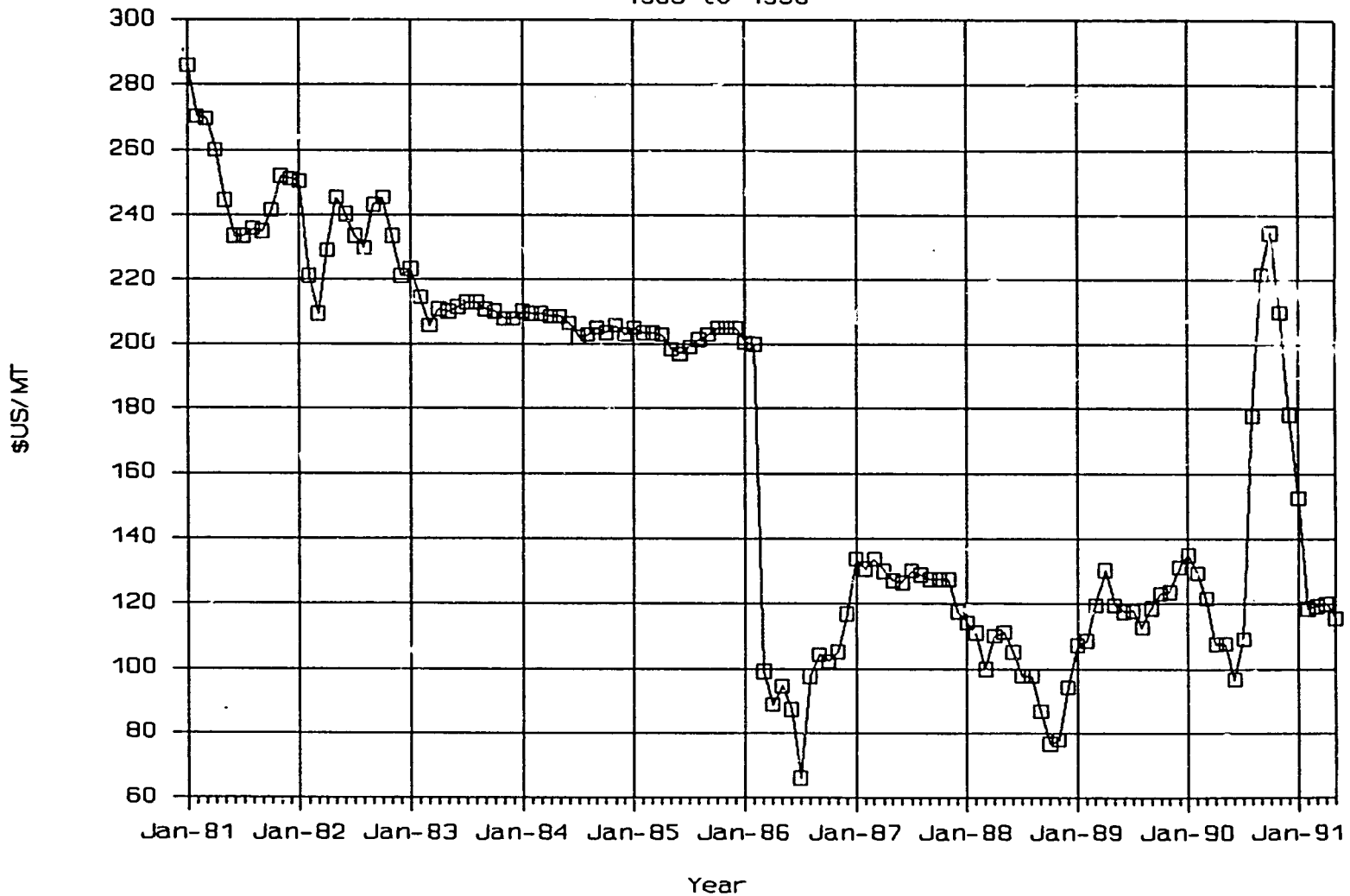
Historical Crude Oil Prices

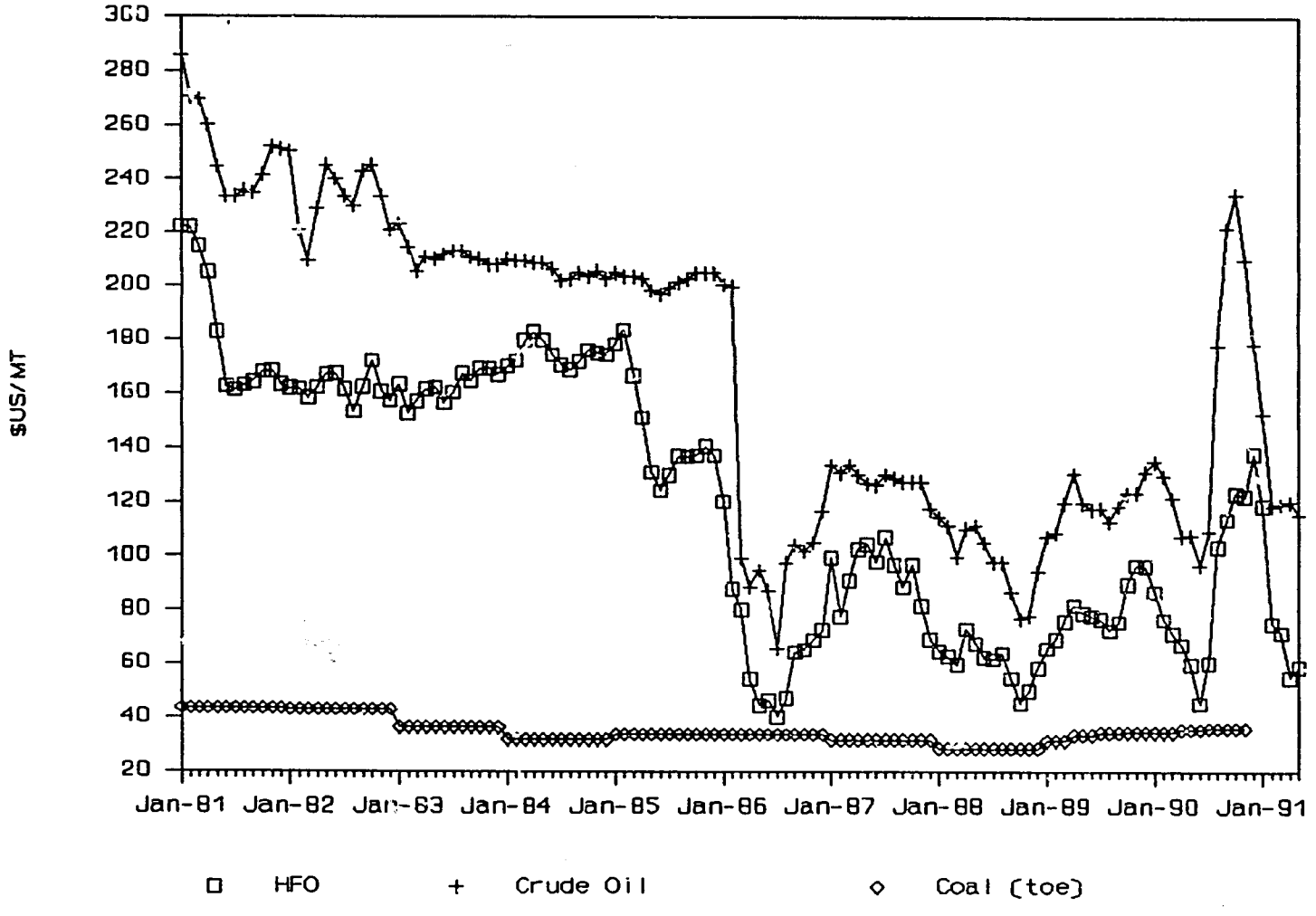


Historical Crude Oil Prices

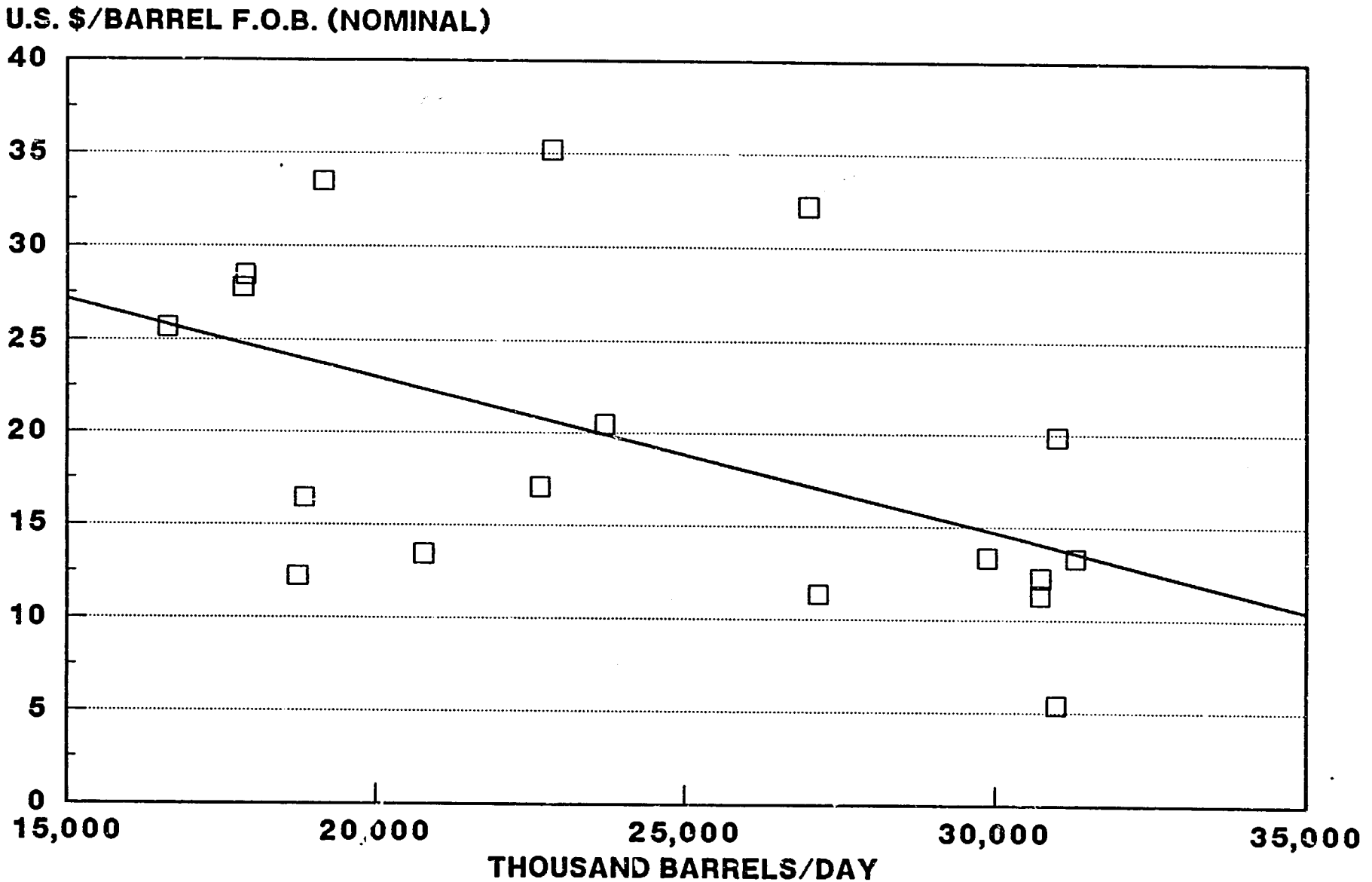
1980 to 1990



Historical Energy Prices



ELASTICITY OF OPEC OIL PRICES



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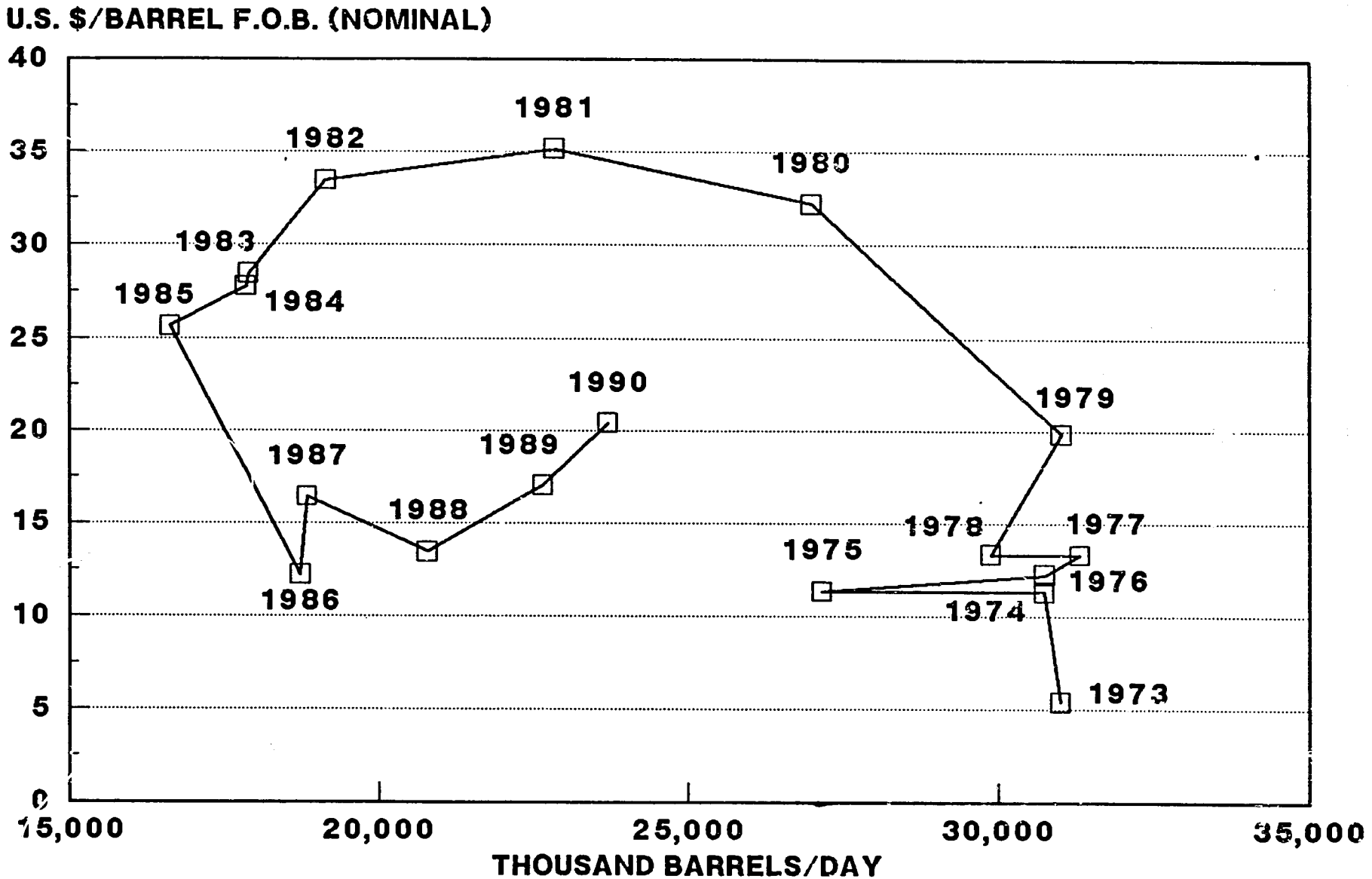
ELASTICITY OF OPEC OIL PRICES



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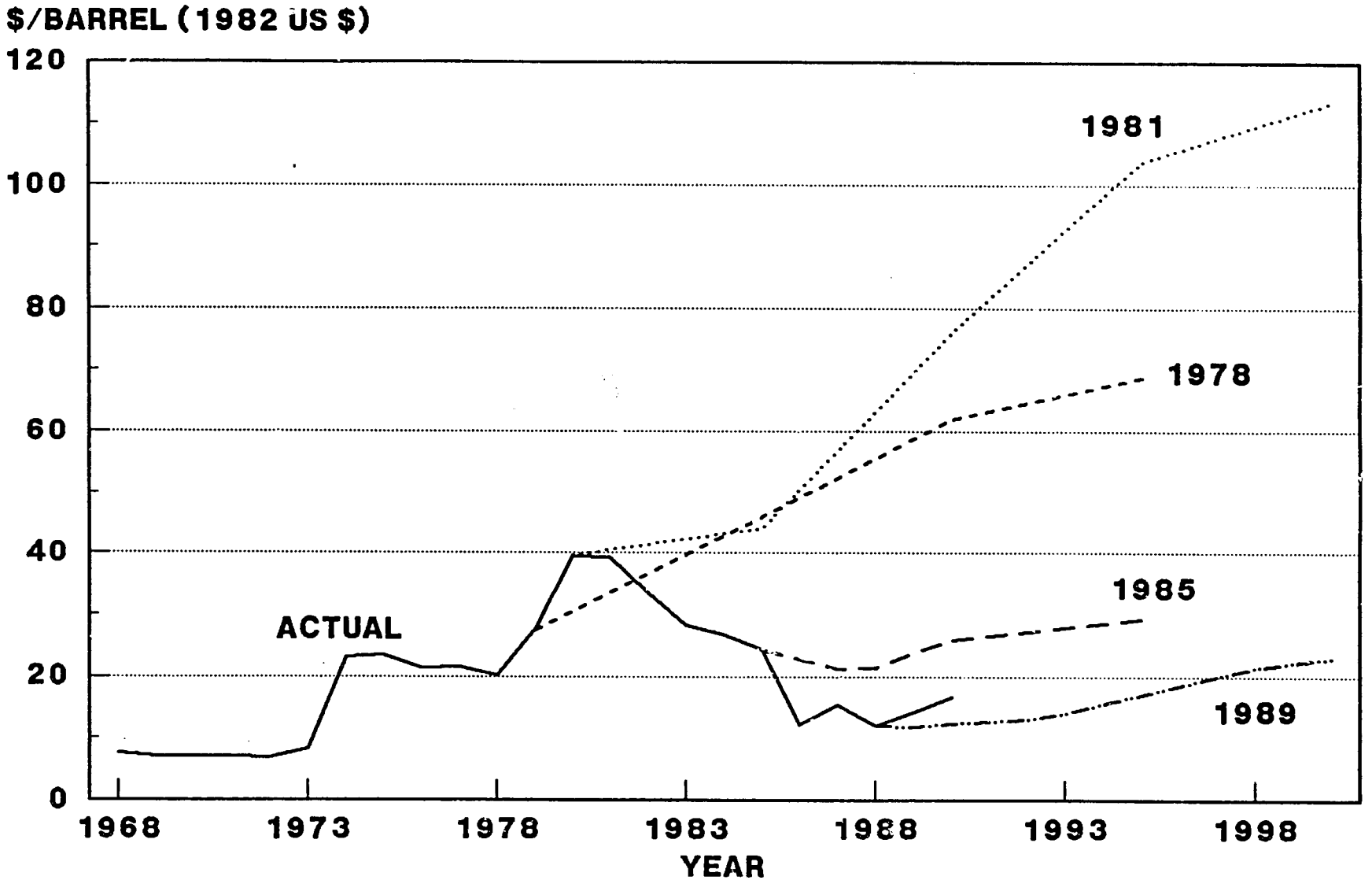
CRUDE OIL FORECASTS



SOURCE: U.S. ENERGY INFORMATION ADMINISTRATION, ANNUAL ENERGY OUTLOOK

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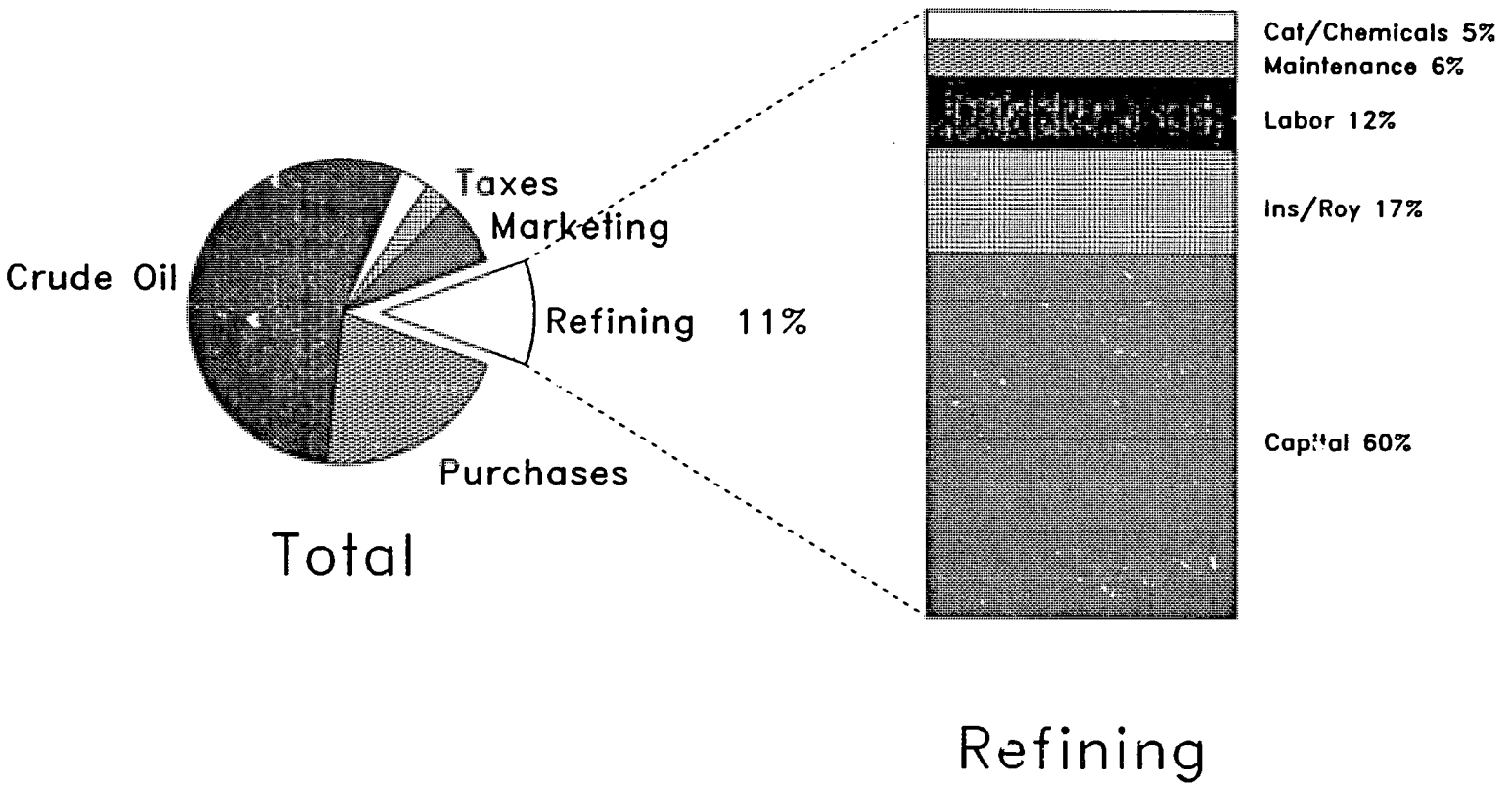
Production Costs

US Experience

Petroleum Costs



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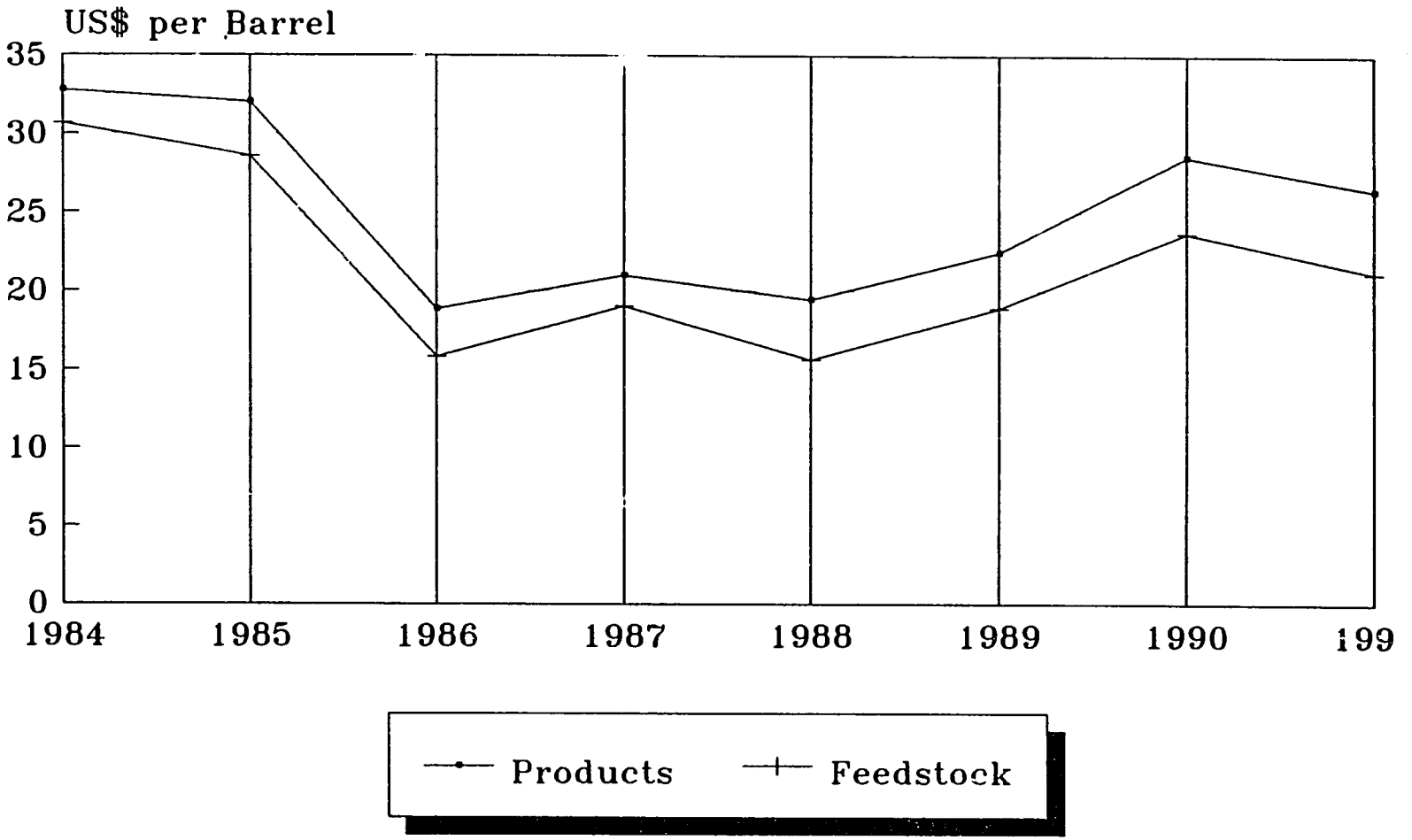
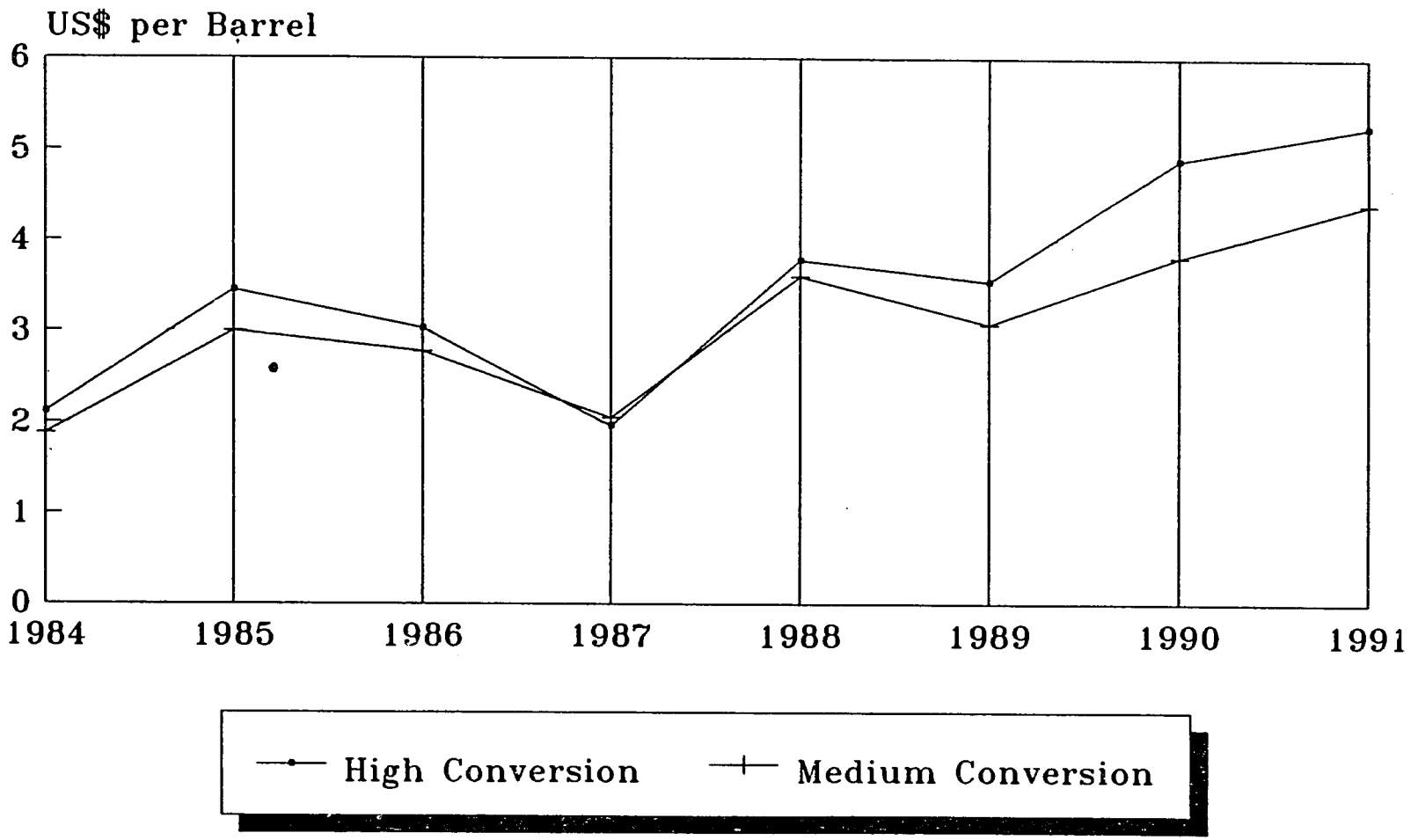
Product Revenue
US Gulf Coast



Refinery Gross Margins
US Gulf Coast



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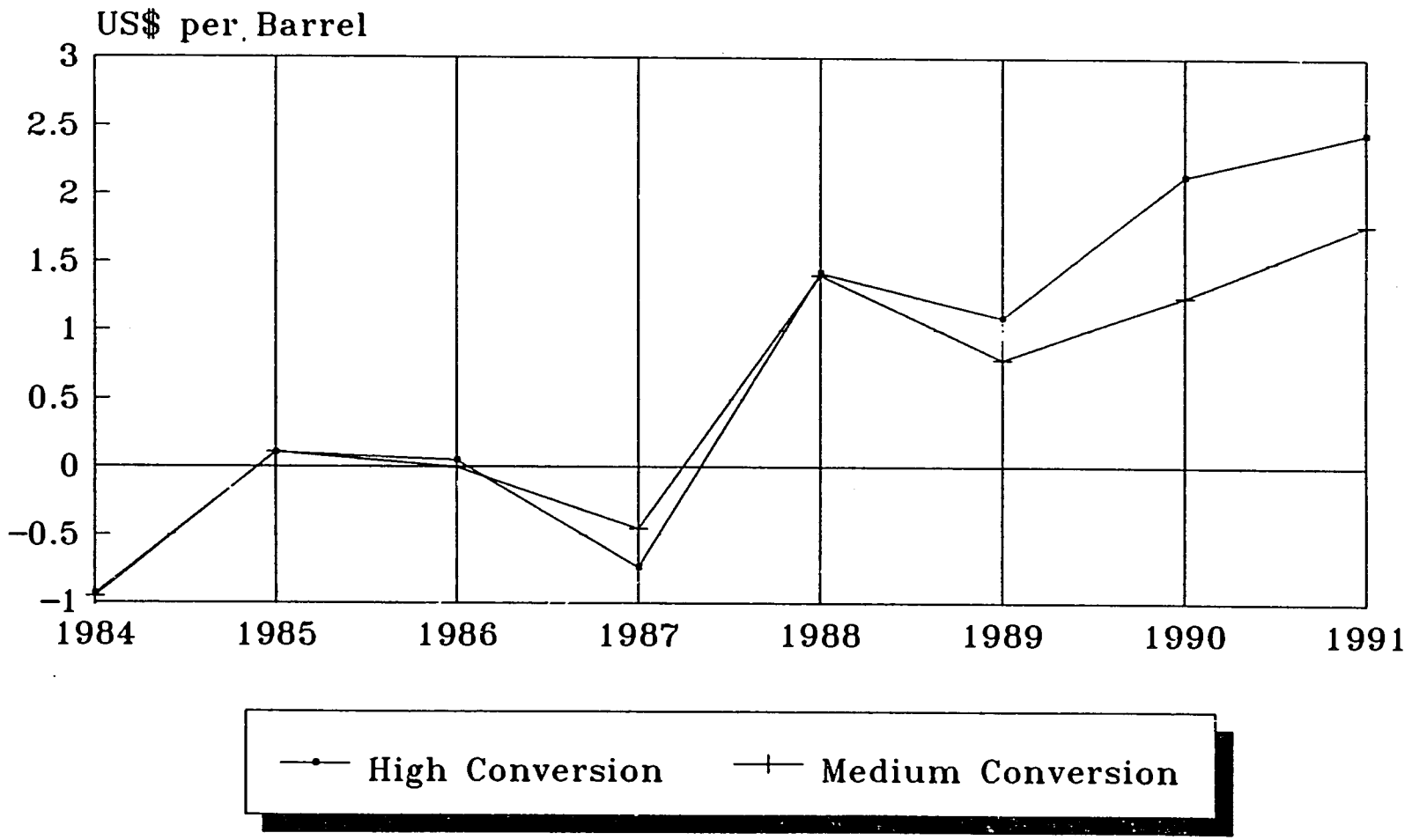
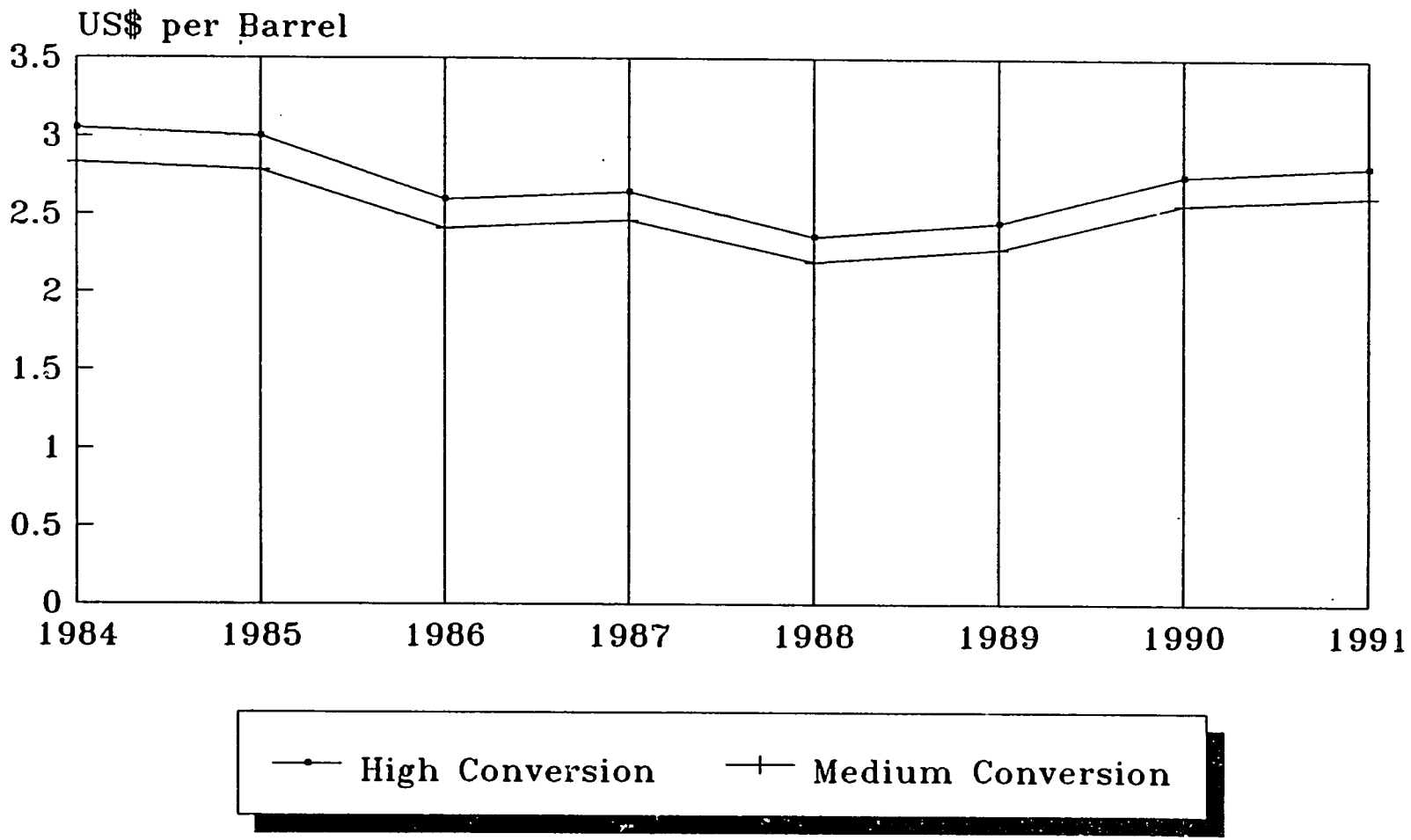
Refinery Cash Margins
US Gulf Coast

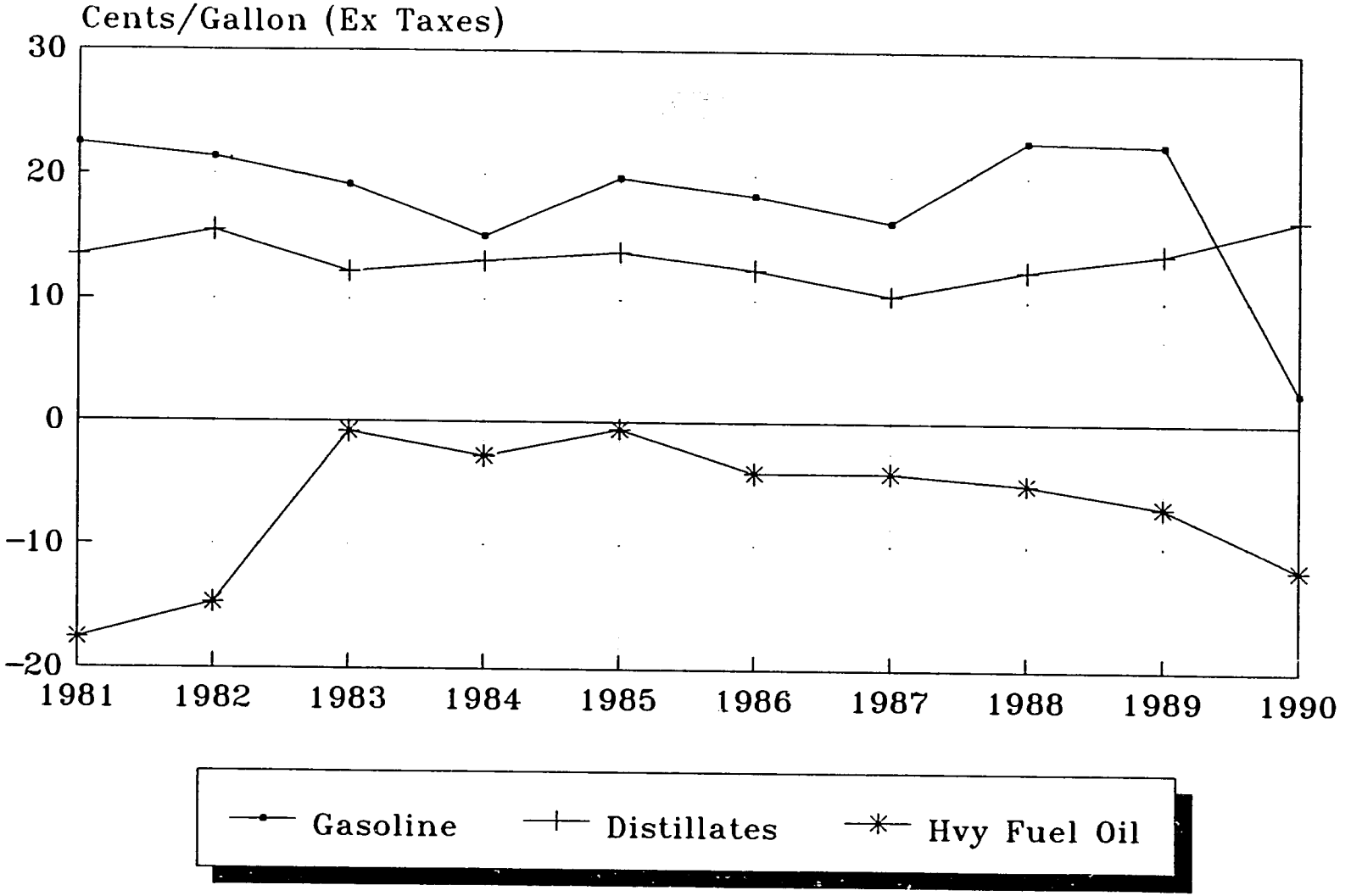


Cash Operating Costs
US Gulf Coast



Coproduct Pricing

Refinery Margins of Selected Products



Source: EIA

Production Costs

- Gasoline - Diesel Price Spread

  Cat Cracker Operating Costs

- Distillate - Residue

  Hydrocracking/Resid Upgrading

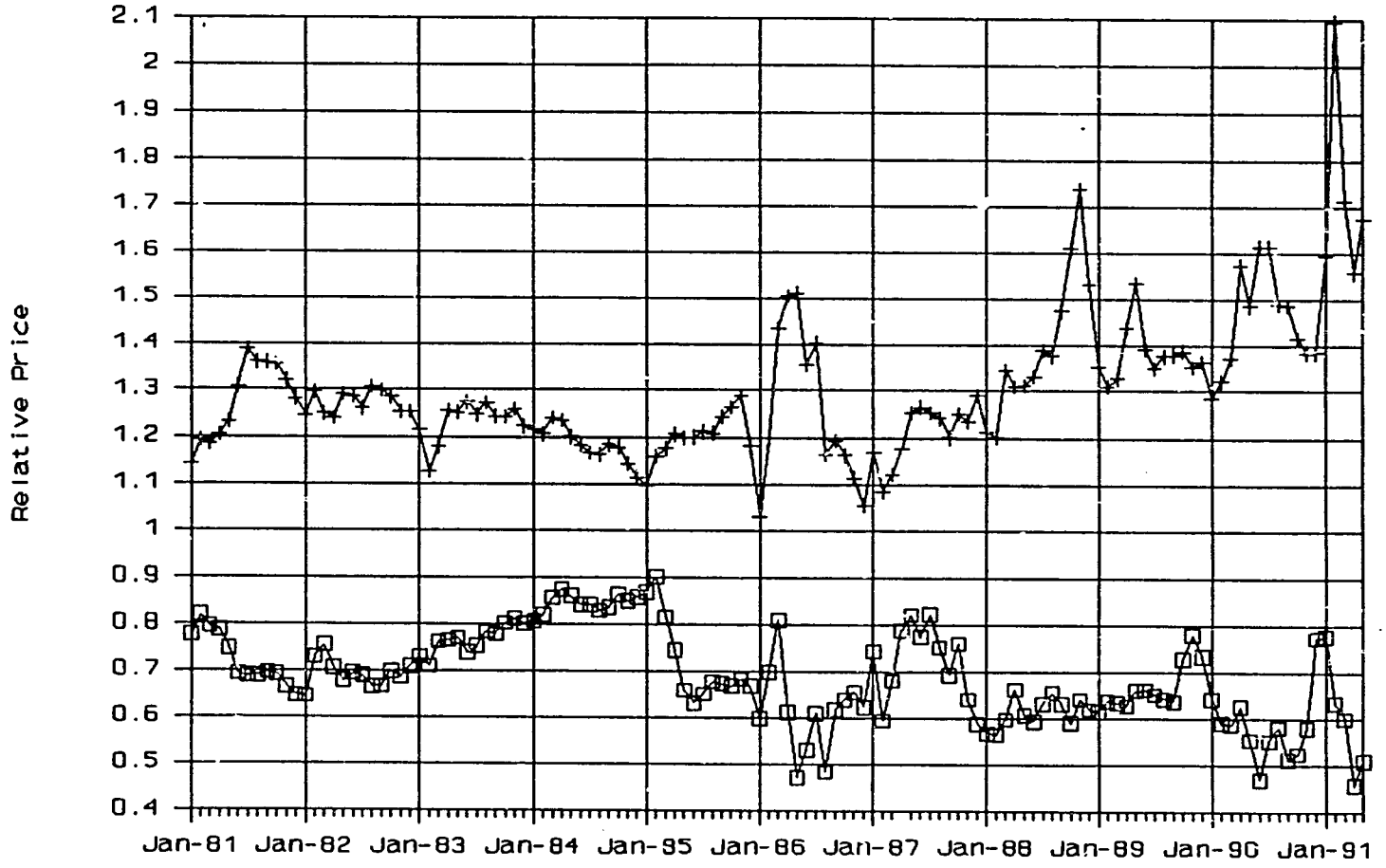
- Crackspread - Nymex

Production Costs

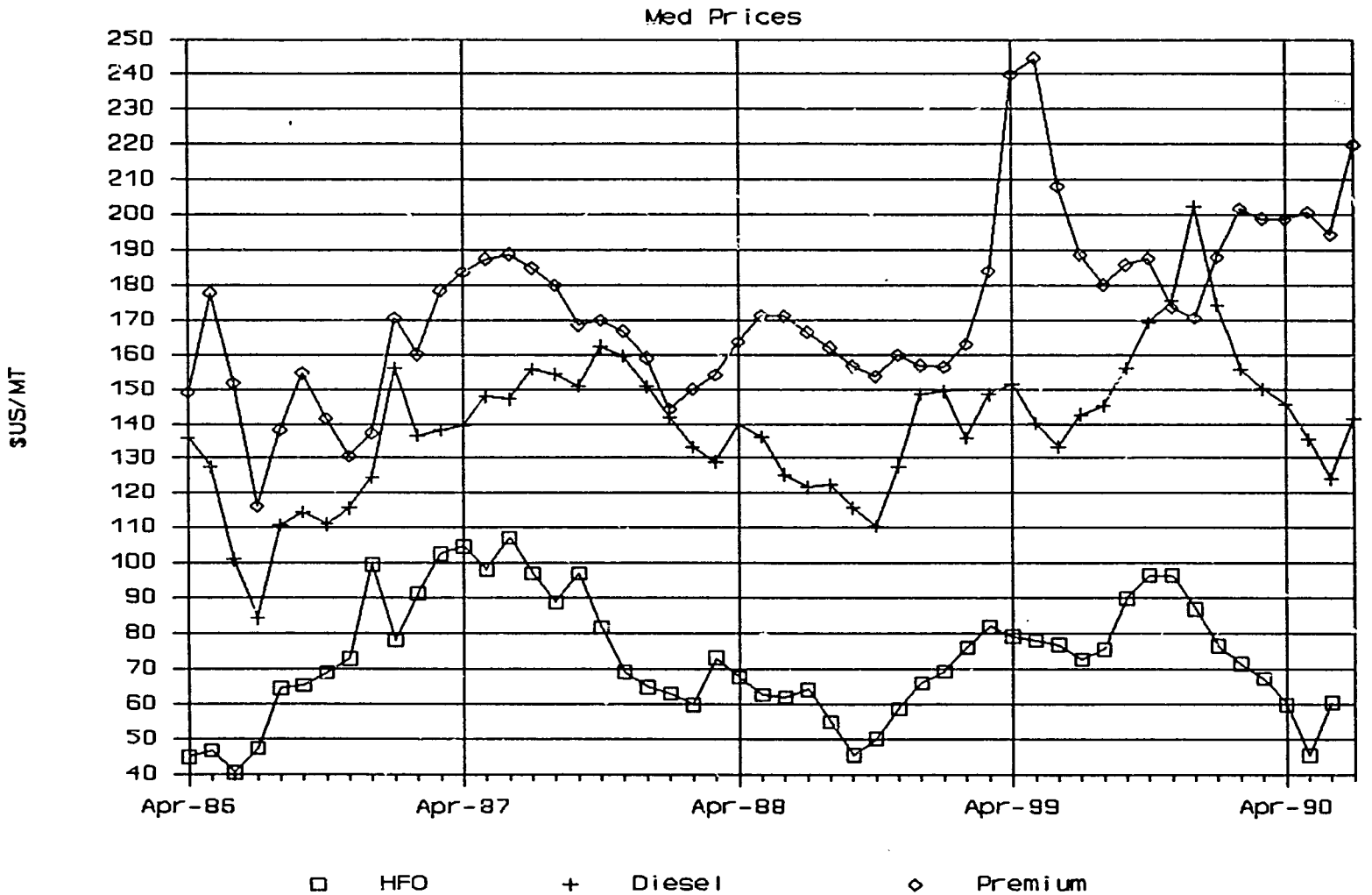
Simulation Models

- Long Range Planning
- Investment Analysis
- Price Input Critical

Product Prices Relative to Crude



Product Price Scenario



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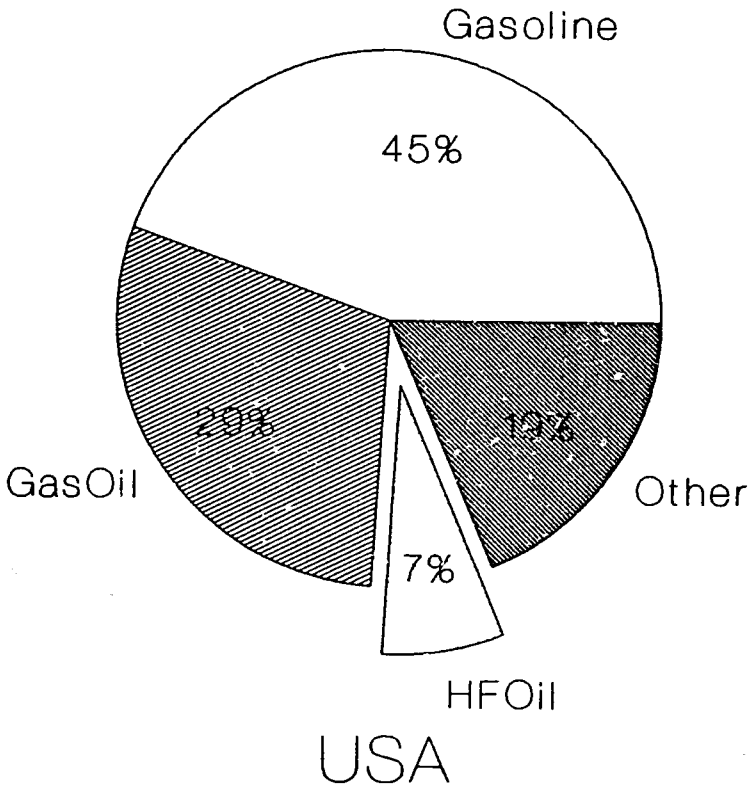
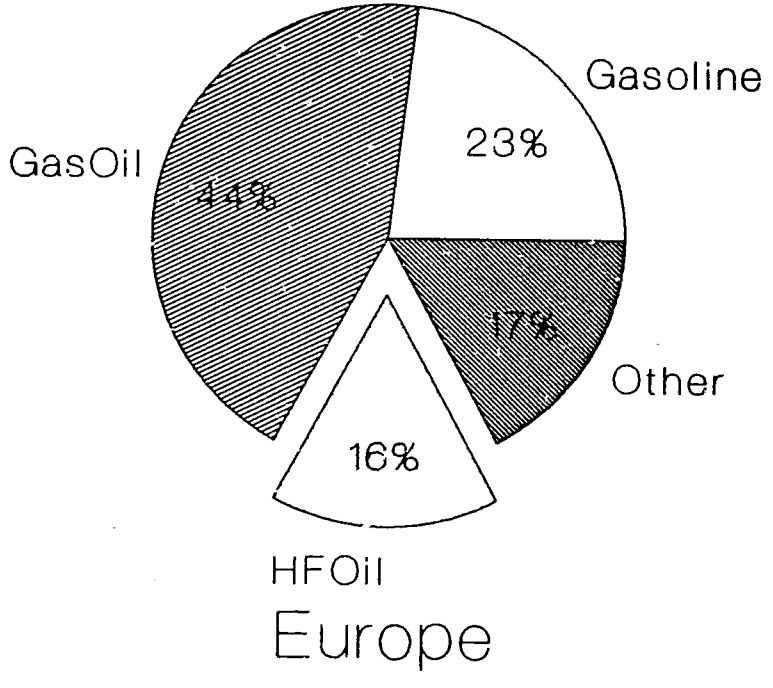
Relative Product Consumptions





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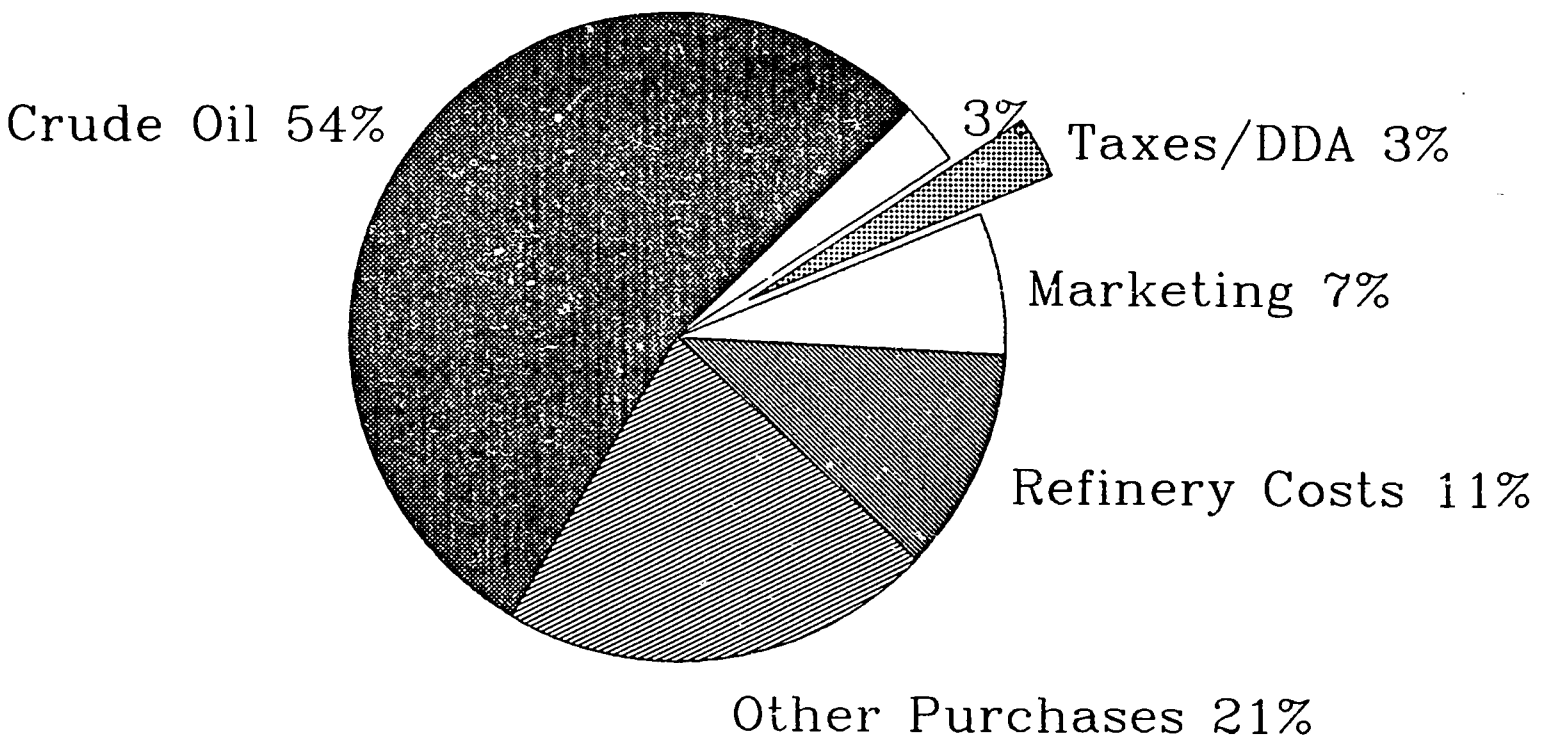
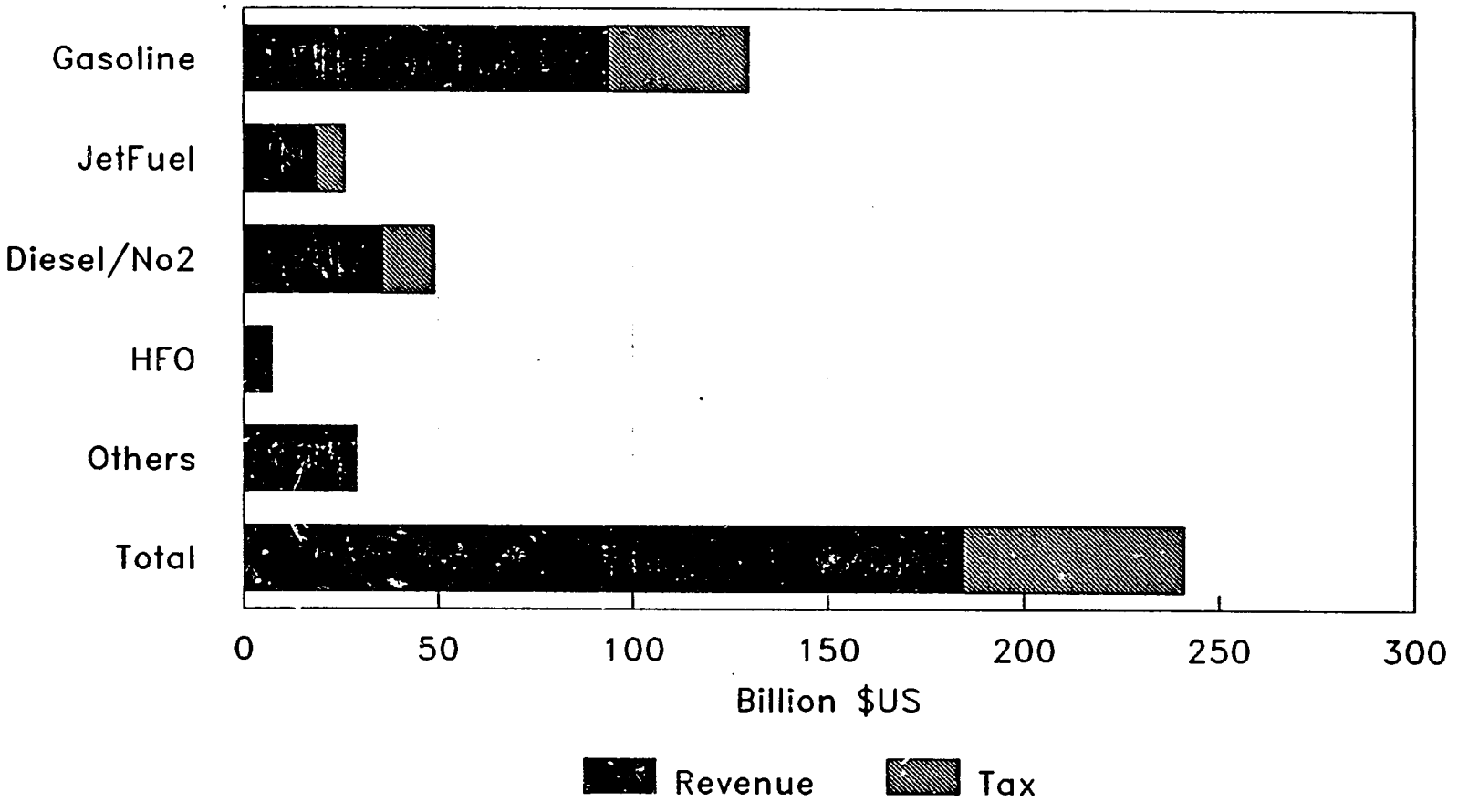
Petroleum Product Prices
US 1989



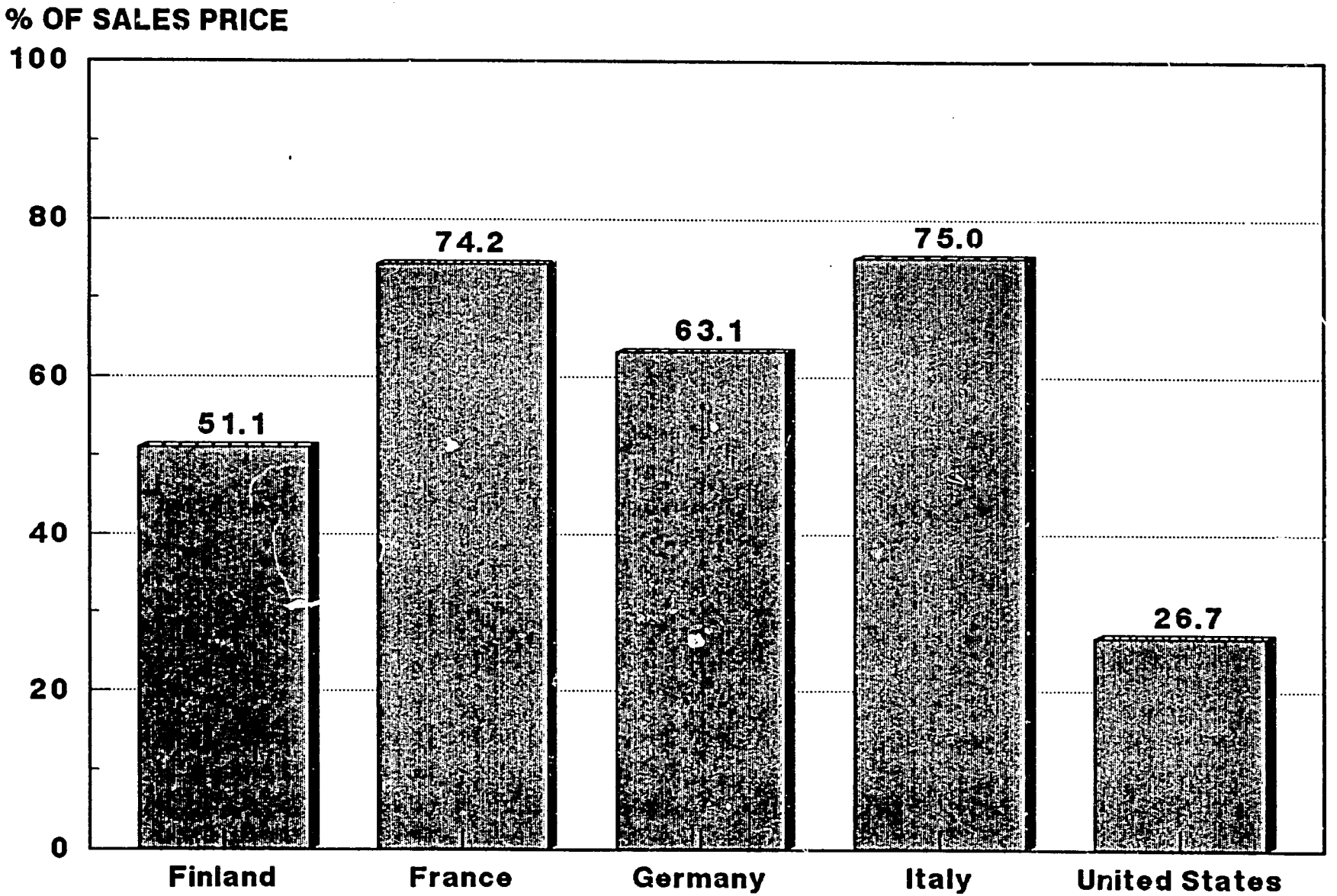
13a

Petroleum Product Revenue
US 1990



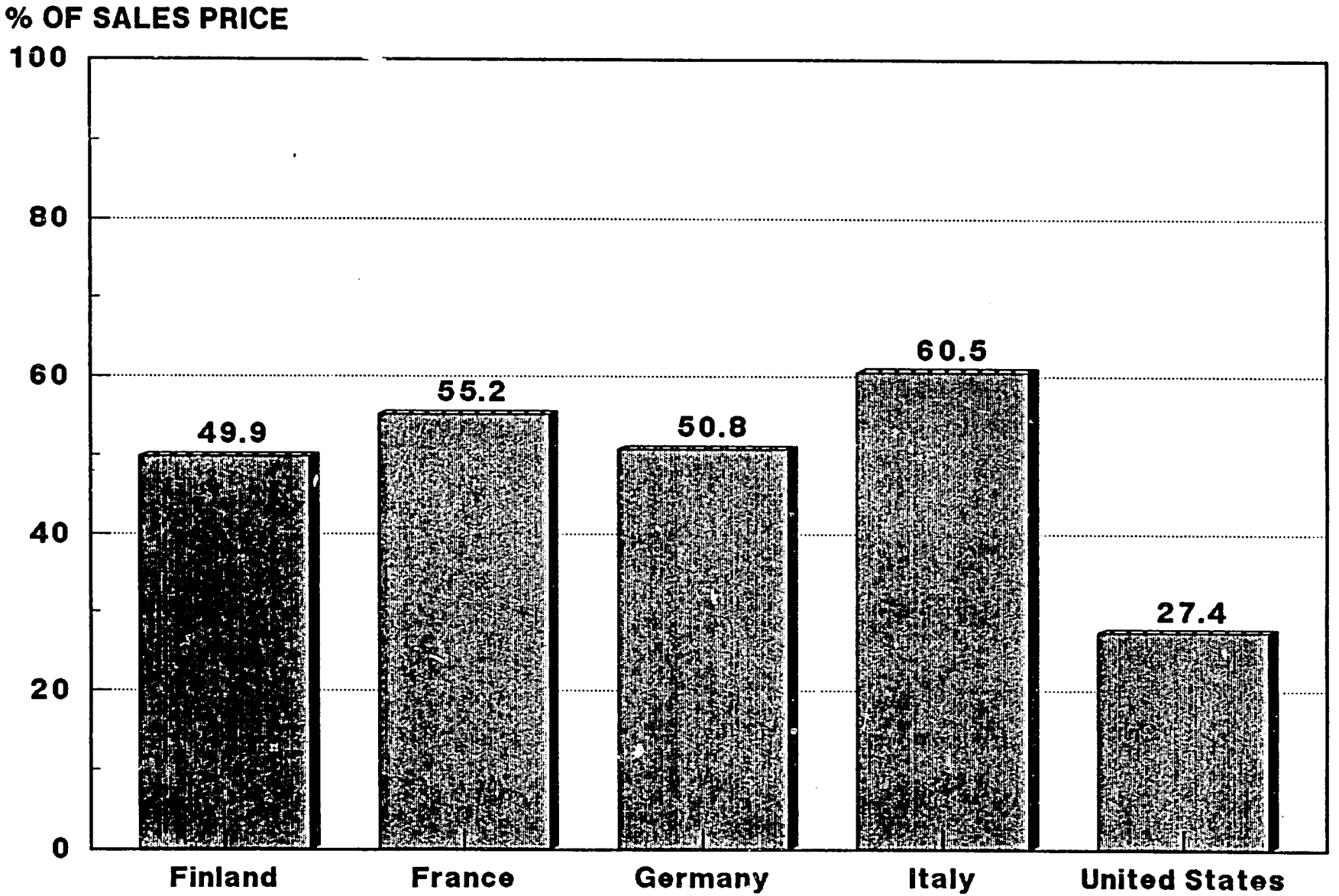
131

TAX ON GASOLINE IN 1990



12

TAX ON AUTOMOTIVE DIESEL FUEL IN 1990



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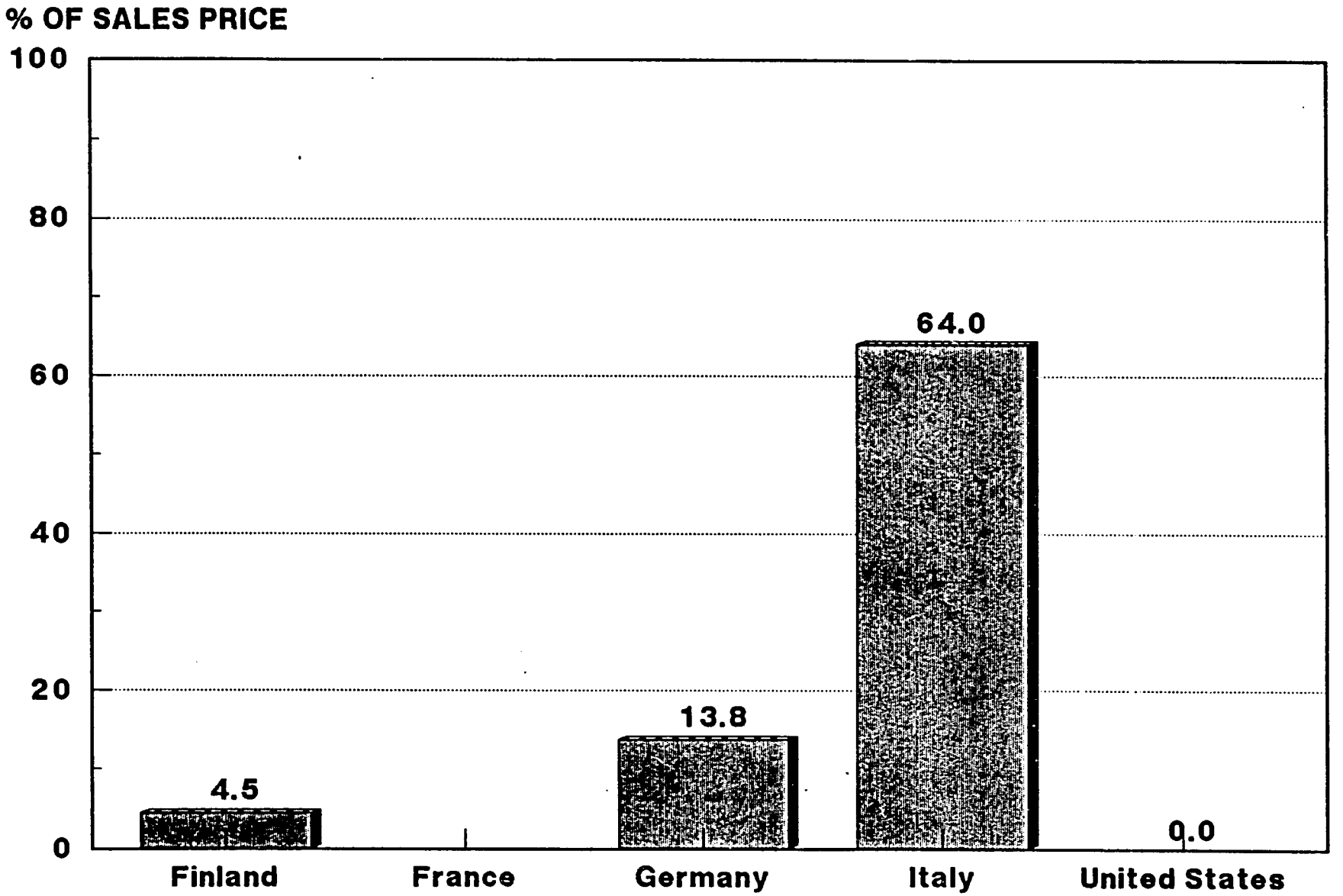
TAX ON LIGHT FUEL OIL IN INDUSTRY IN 1990



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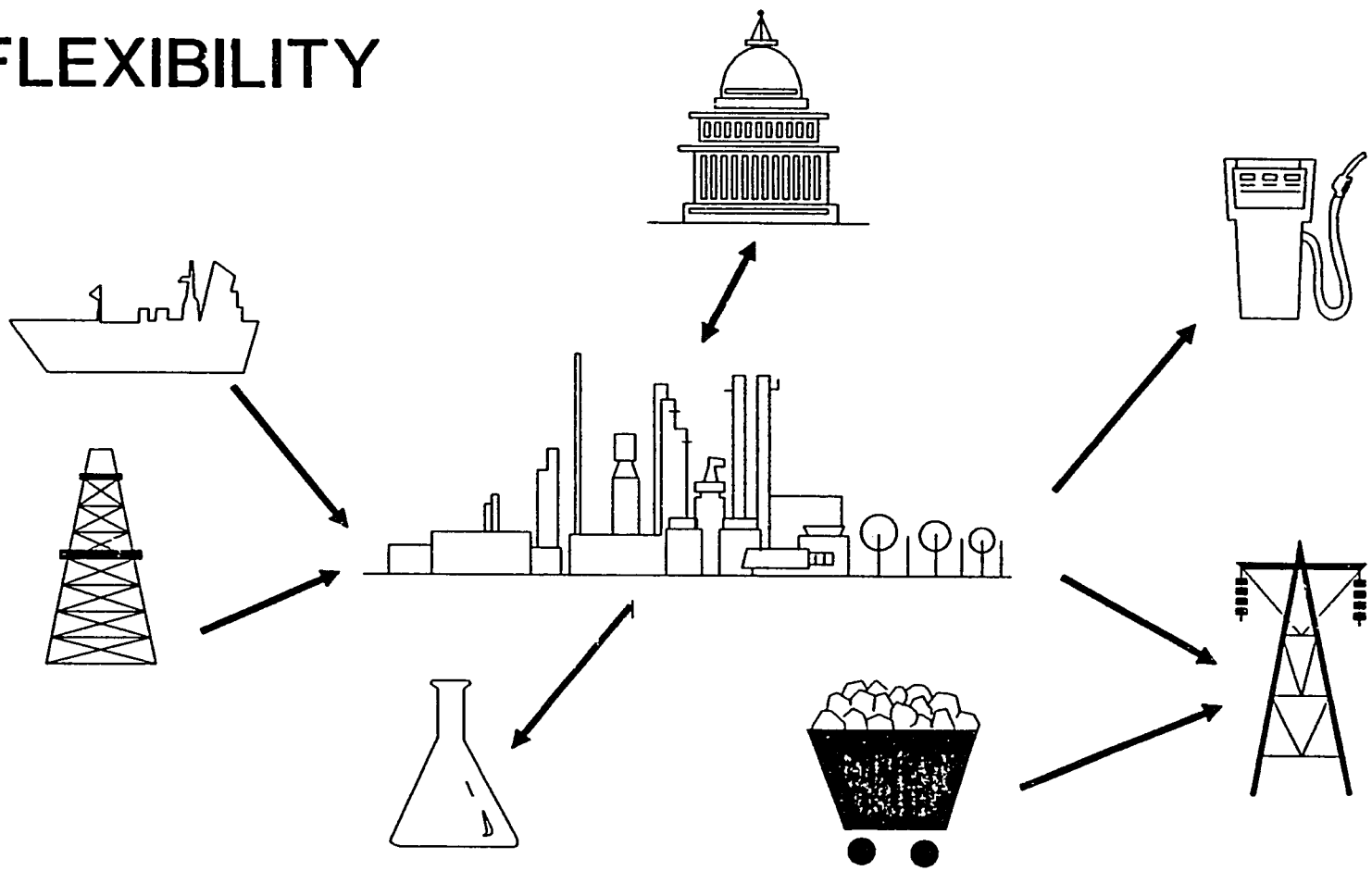
FUTURE OUTLOOK

- FLEXIBILITY



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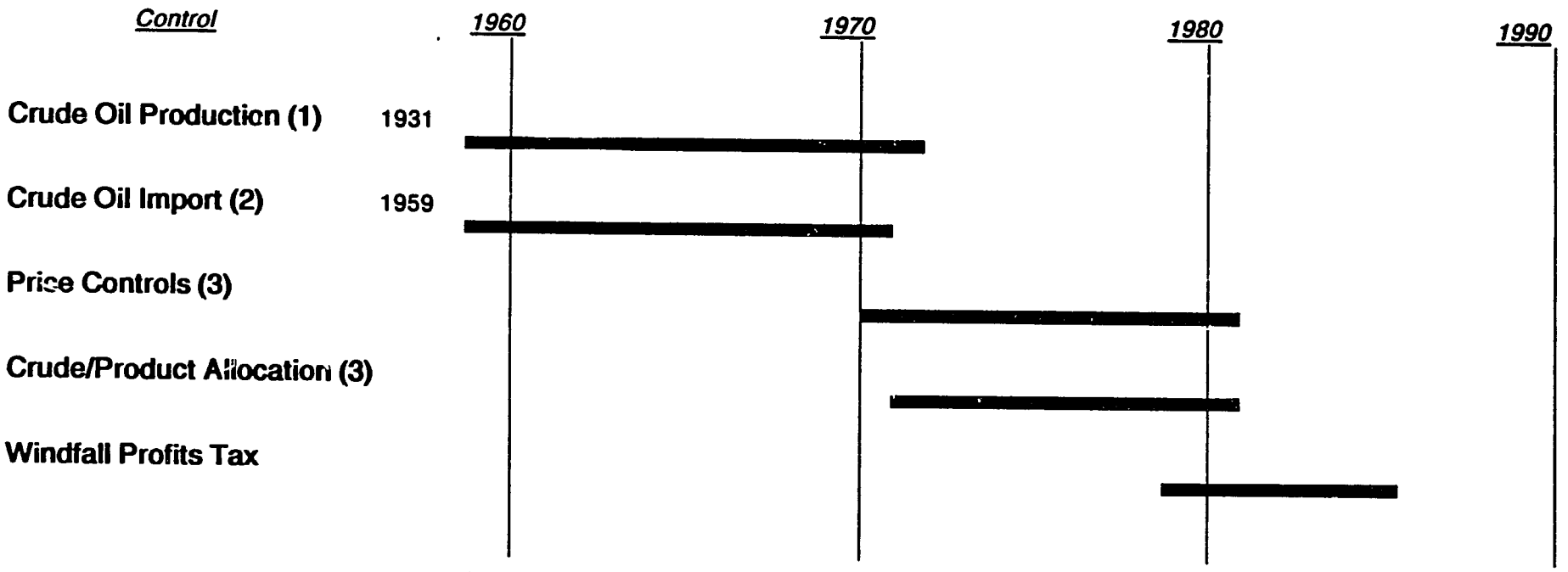
History of Petroleum Regulation in the US



(1) Prorationing by Texas Railroad Commission

(2) Mandatory Oil Import Policy

(3) Mandatory Pricing and Allocation Regulations

PRICING POLICY - MODE

POLITYKA CENOWA SPOSÓB

- PRICE CONTROLS
  Kontrole Cen
- FREE MARKET
  Wolny Rynek
- ???

G-14

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PRICING POLICY - OBJECTIVES

POLITYKA CENOWA CELE

- Price Stabilization
  Stabilizacja Cen
- Conservation
  Oszczedność
- Social Subsidy
  Subsydia Socjalne
- Government Revenue Generation
  Wytwarzanie dochodu narodowego
- Domestic Industry Protection / Windfall Profits
  Ochrona przemysłu krajowego Nieoczekiwane zyski
- Prevent Windfall Profits
  Zapobiec nieoczekiwanym zyskom
- Environmental
  Środowiskowe

G-15

PRICING POLICY - MECHANISM

POLITYKA CENOWA

Mechanika

- Price Controls
  Kontrola Cen
- Import Controls
  Kontrole Importów
- Taxes and Duties
  Podatki I Cła
- Profit - Windfall Controls
  Zyski - Kontrola nieoczekiwanych zysków
- Enduse Controls
  Kontrola użytkowania
- Substitute Energy Price Controls
  Substytuty Kontroli Cen Energii (kontrola zastępcza)

G-16

Pricing Policy

POLITYKA CENOWA

FUTURE OUTLOOK

PRZYSZŁE PROGNOZY

- VOLATILITY - PETROLEUM

  Zmienność - Ropa Naftowa

- COMPETITION - GAS & COAL

  Współzawodnictwo - Gaz I Wegiel

- FLEXIBILITY

  Elastyczność

G-17

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US Oil Policy 1950 - 1973

Polityka Naftowa Ameryki 1950-1973

- Crude Oil Production Prorationing
  Racjonowanie Produkcji Ropy Naftowej
- Crude Oil Import Controls (MOIP)
  Kontrola importu ropy naftowej

M-3

MOIP

- Oil Imports Restricted
  Ograniczony import ropy naftowej
- Heavy Fuel Oil Exempt into East Coast
  Ciężkie oleje Napedowe wyłączone na Wschodnim Wybrzeżu
- Selective Exceptions Multiplied
  Wybrane wyjątki zwielokrotnione

m4

MOIP

Results

RESULTATY

- Refining Industry → Caribean Karaiby
  Przemysł Rafineryjny → Offshore Przybrzežny
- Petrochemical Industry → Europe
  Przemysł petrochemiczny
  Europa
- Excess Naphtha Imports → SNG
  Nadwyžka
  Importu → Chemicals

US Oil Policy 1973 - 1985

Amerykańska Polityka Naftowa 1973-1985

- Price Controls
  Kontrole Cen
- Allocation of Products
  Rozdział produktów
- Allocation of Crude Oil
  Rozdział ropy naftowej

M6

US Oil Policy 1981 -

AMERYKAŃSKA POLITYKA NAFTOWA 1981 -

- Free Market Prices
  Wolne Ceny Rynkowe
- End-user Restrictions
  Restrykcje użytkowników
  - Automobile Efficiency
    Wydajność samochodów osobowych
  - Taxes
    Podatki
- Environmental Restrictions
  Restrykcje Środowiskowe
  - Clean Air Act
    Ustawa o "Czystym Powietrzu"

M-7

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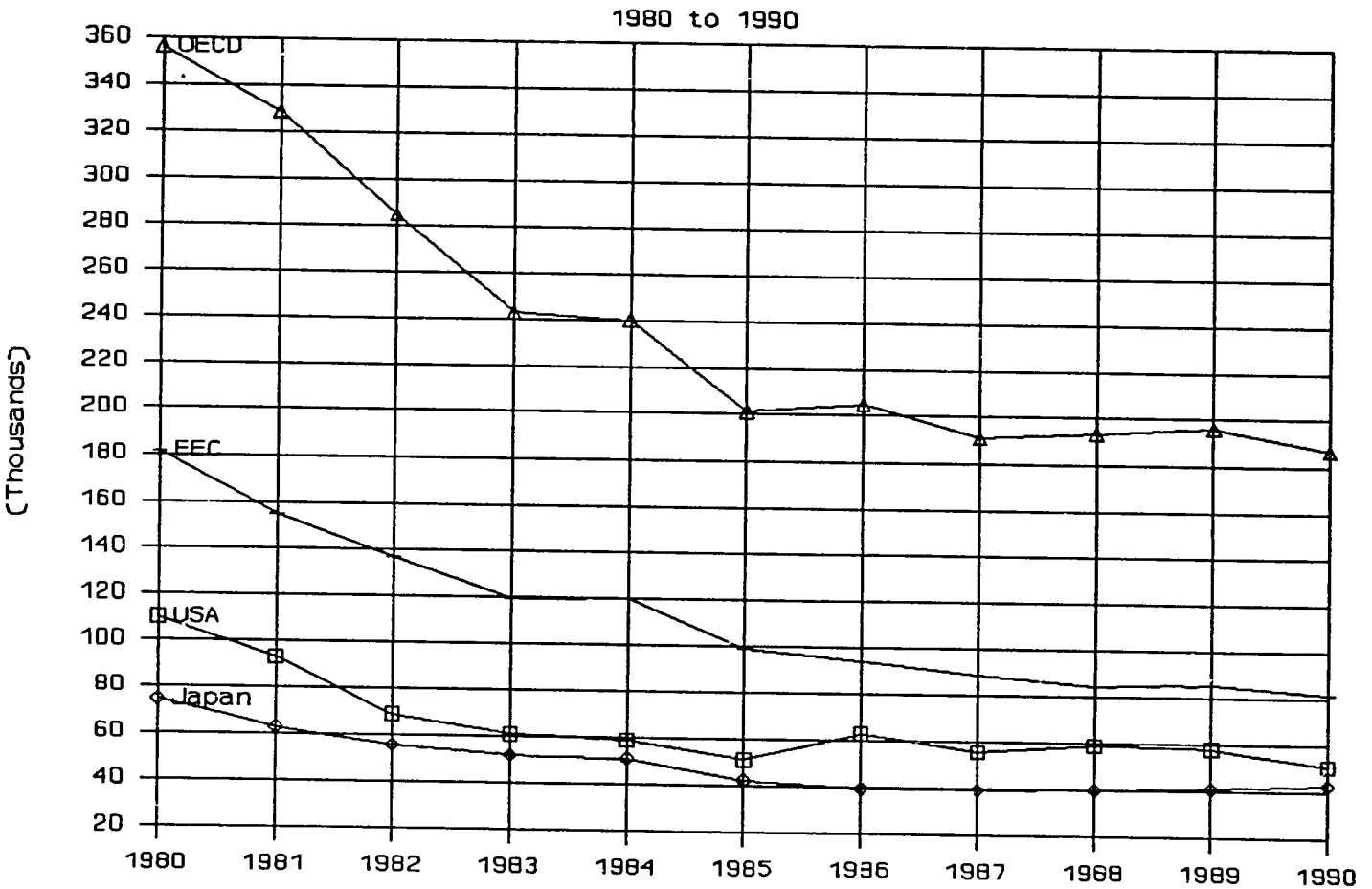
Ceny Miedzynarodowe

International Prices 1980s

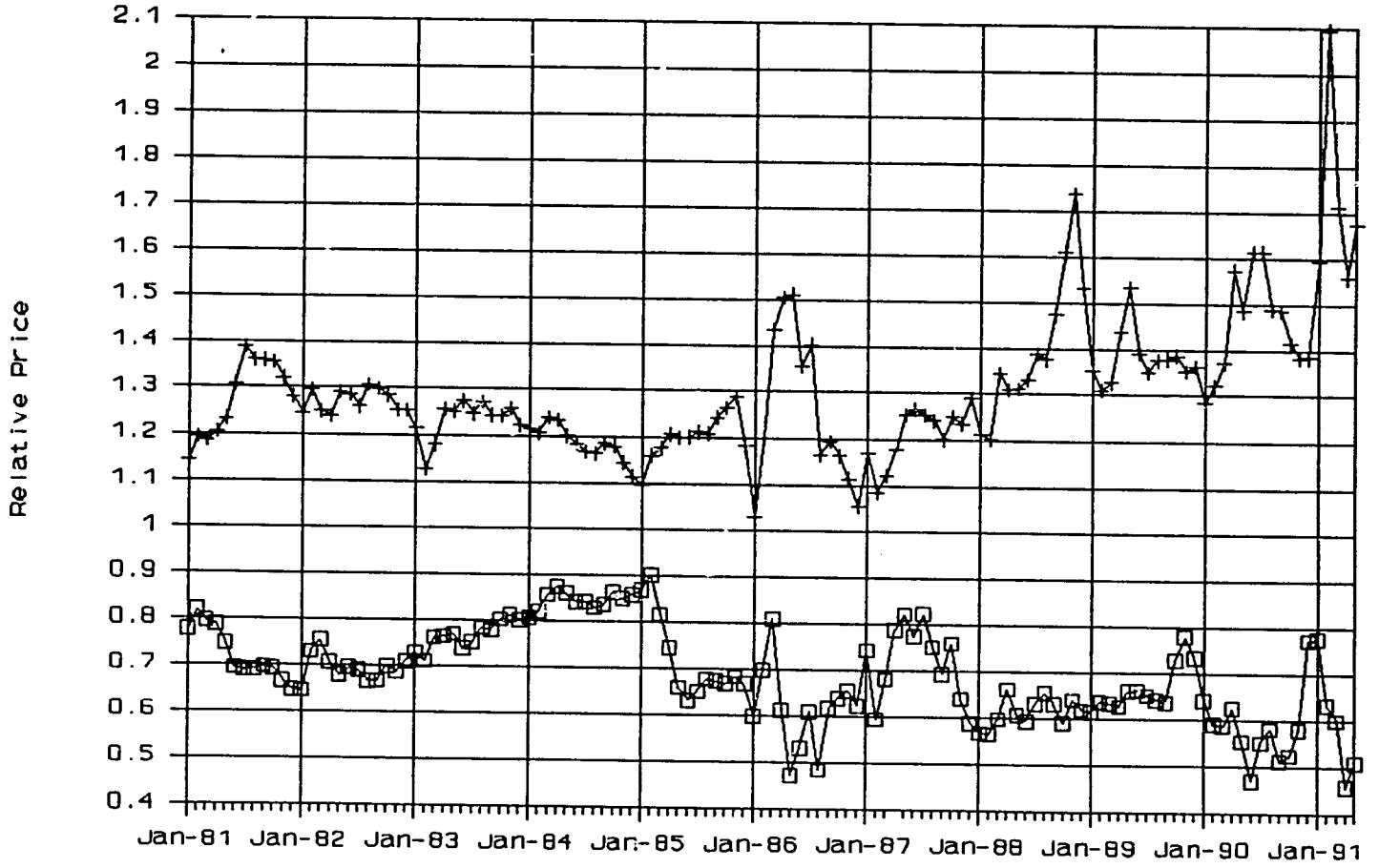
Ceny Miedzynarodowe

International Prices 1980s

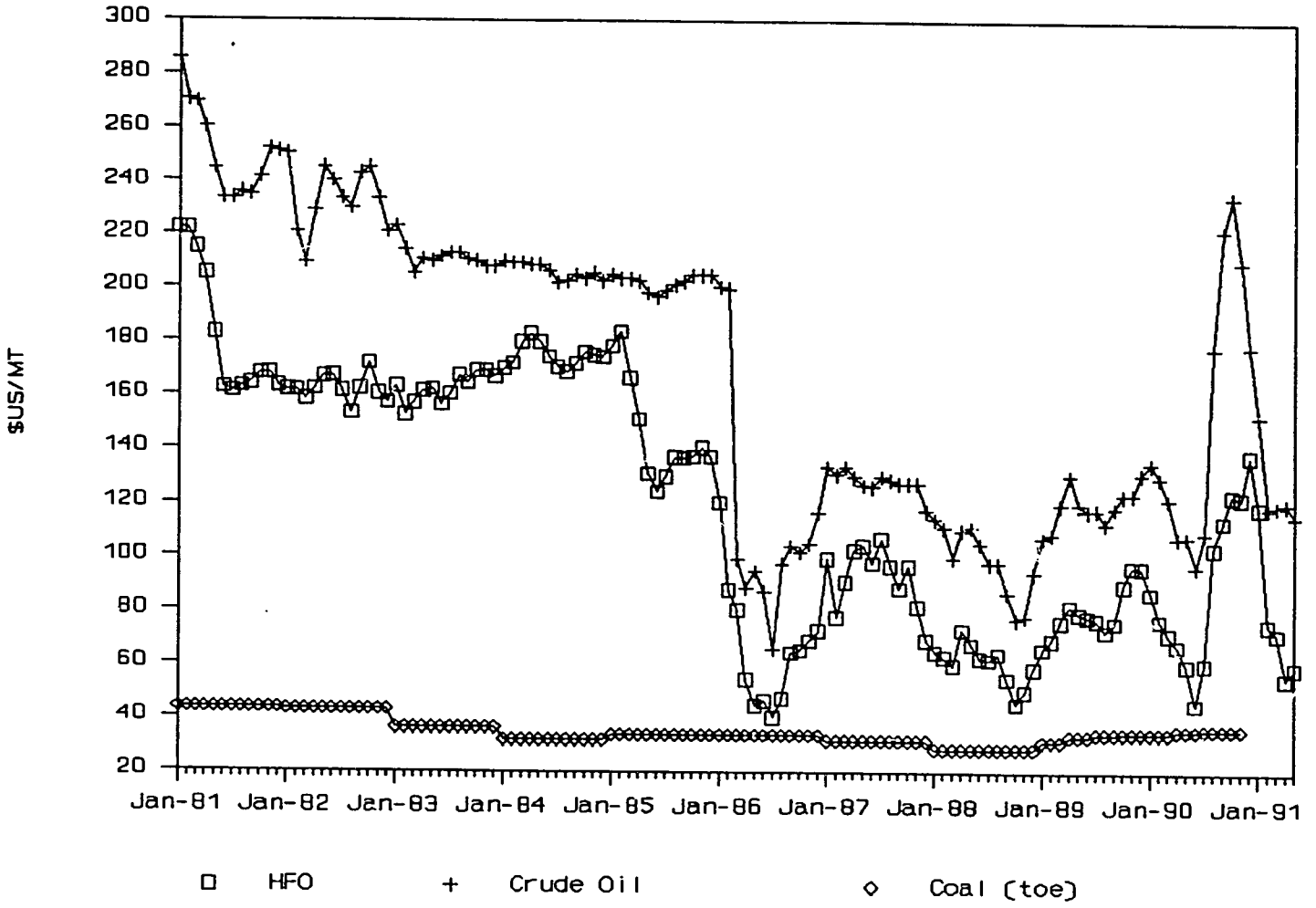
Heavy Fuel Oil Consumption



Product Prices Relative to Crude



Historical Energy Prices



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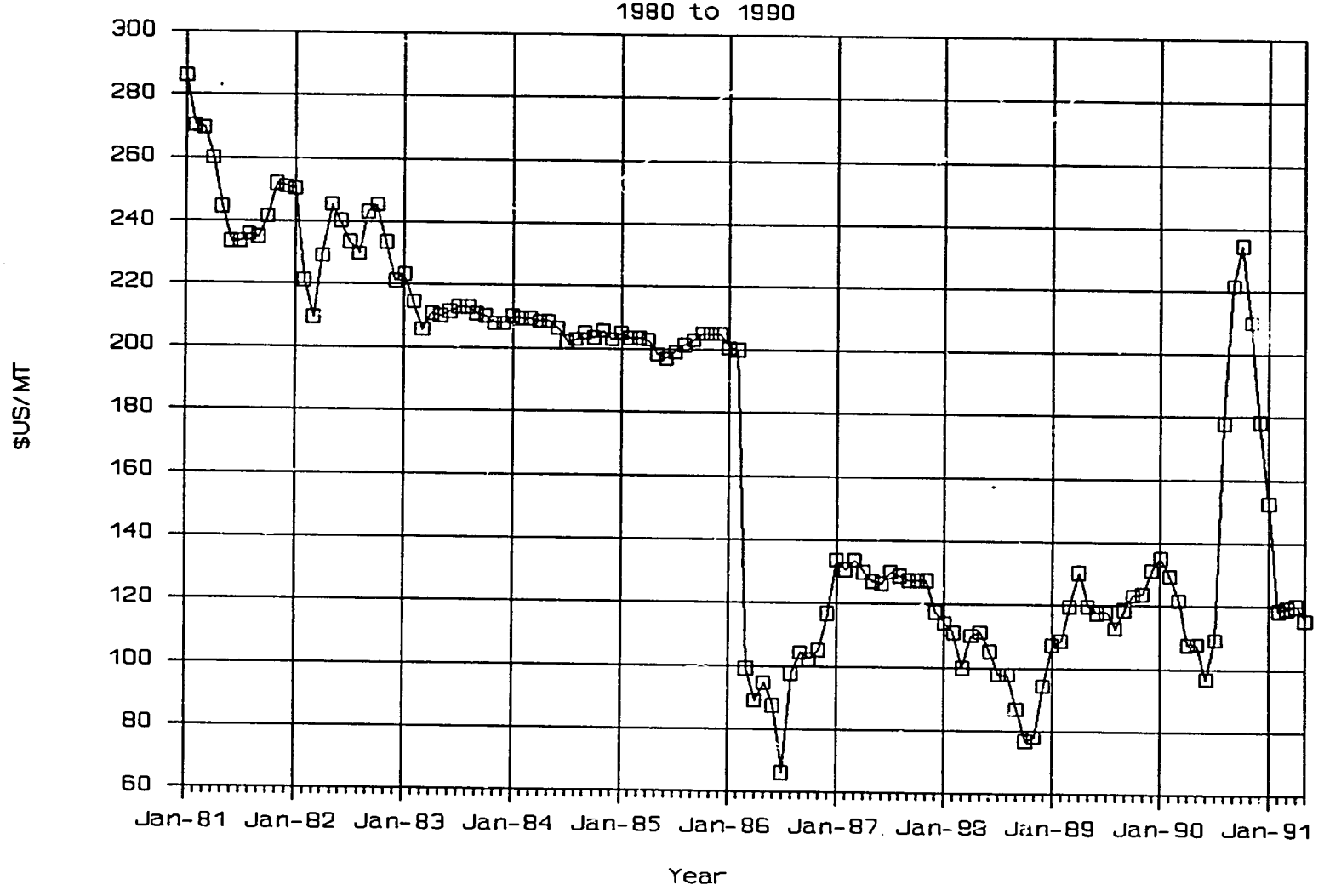
Historical Crude Oil Prices

1980 to 1990



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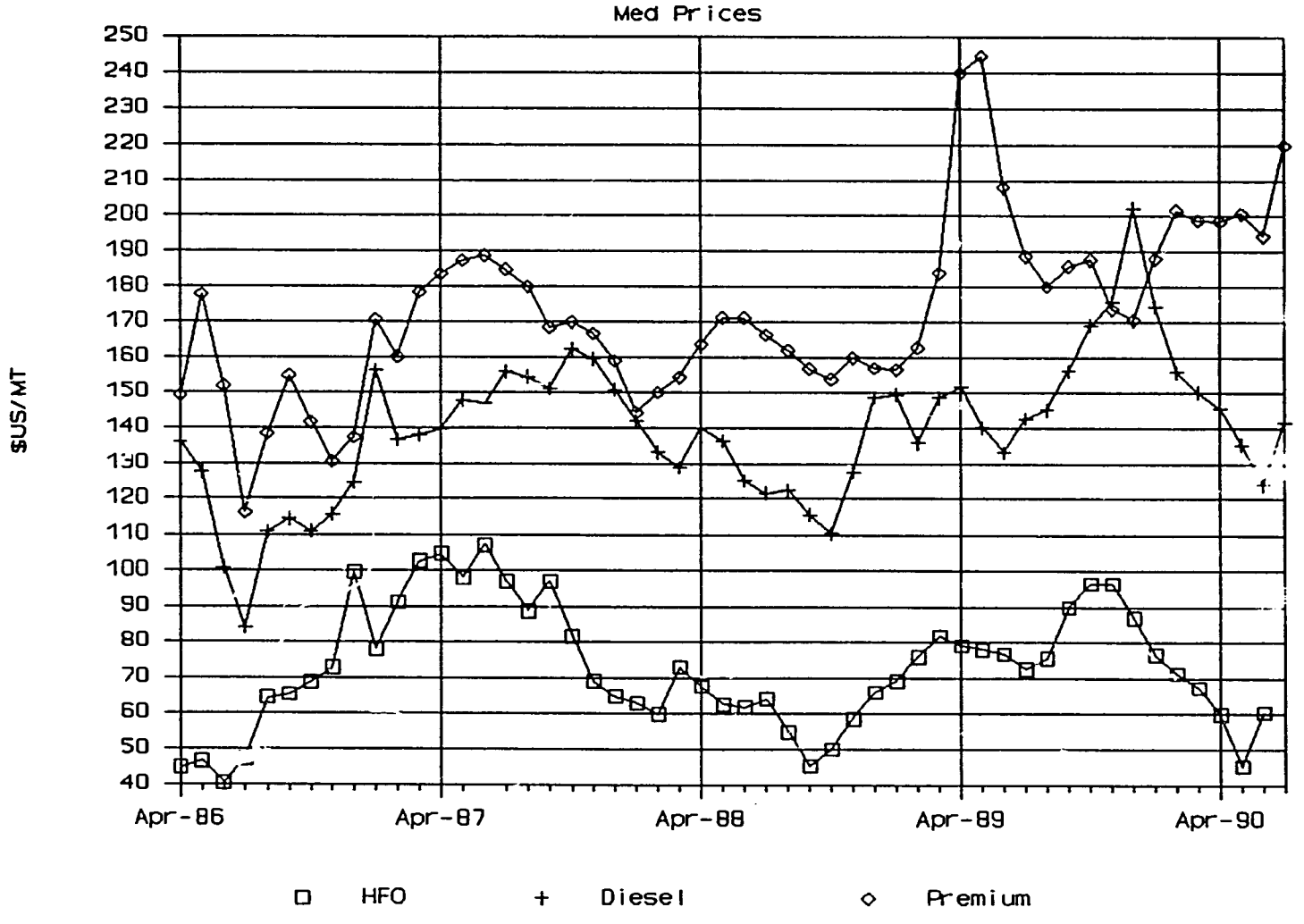
Product Price Scenario



Energy Pricing Seminar: Poland

Thaddeus J. Huetteman

Slide/Type		Title
1	Chart	Current Criteria: Restructuring Polish Hard Coal Industry - Size Limit Productivity Mix
2	Text	Current Criteria: Size Limits/Productivity Mix
3	Chart	Suggested Additional Criterion: Coal Quality
4	Text	Investing by Coal Quality: Permits Numerous Steam Coal Market "Plays"
5	Text	Overview of the Argument
6	Text	Is There A "World" Coal Market?
7	Chart	World Demand Outlook: Steam Coal Imports Surges/Met Coal Declines
8	Chart	Asian Supply Outlook: New Pacific Coal Output Stays in the Pacific
9	Chart	European Supply Outlook: Will Eastern Europe Stay in the Game?
10	Text	Hard Coal Price Formation: Theory/Steam Coal Market Segmentation
11	Text	Short Term: Demand - Driven Prices
12	Test	Long Term: Supply - Driven Prices
13	Text	Domestic Steam Coal Markets - Pricing Components
14	Text	World Steam Coal Markets
15	Text	Lignite Price Formation: Practice
16	Chart	Imported Steam Coal Price Outlook: No Real Growth Through 1995; Stronger Through 2000
17	Chart	Does the European Market Reward Quality? U.S. Steam Coal Low Sulfur Price Premiums 1990-1991
18	Chart	EC SO_2 Reduction Targets, 1980 - 2003
19	Chart	1980 EC SO_2 Emissions Shares vs FGD Capacity (Installed/Planned)

TJH.other.Poland.NDS.kda.8/30/91

Slide/Type	Title
20 Chart	Netback Valuation of Polish Coal Traditional (Steam Coal)
21 Chart	Busbar Cost Basis
22 Text	Lessons from Fuel Switching in America
23 Text	Economics of Coal Cleaning
24 Text	Clean Air Act & SO_2 Allowances
25 Text	Buying Coal Quality
26 Text	Summary

RESTRUCTURING POLISH HARD COAL INDUSTRY

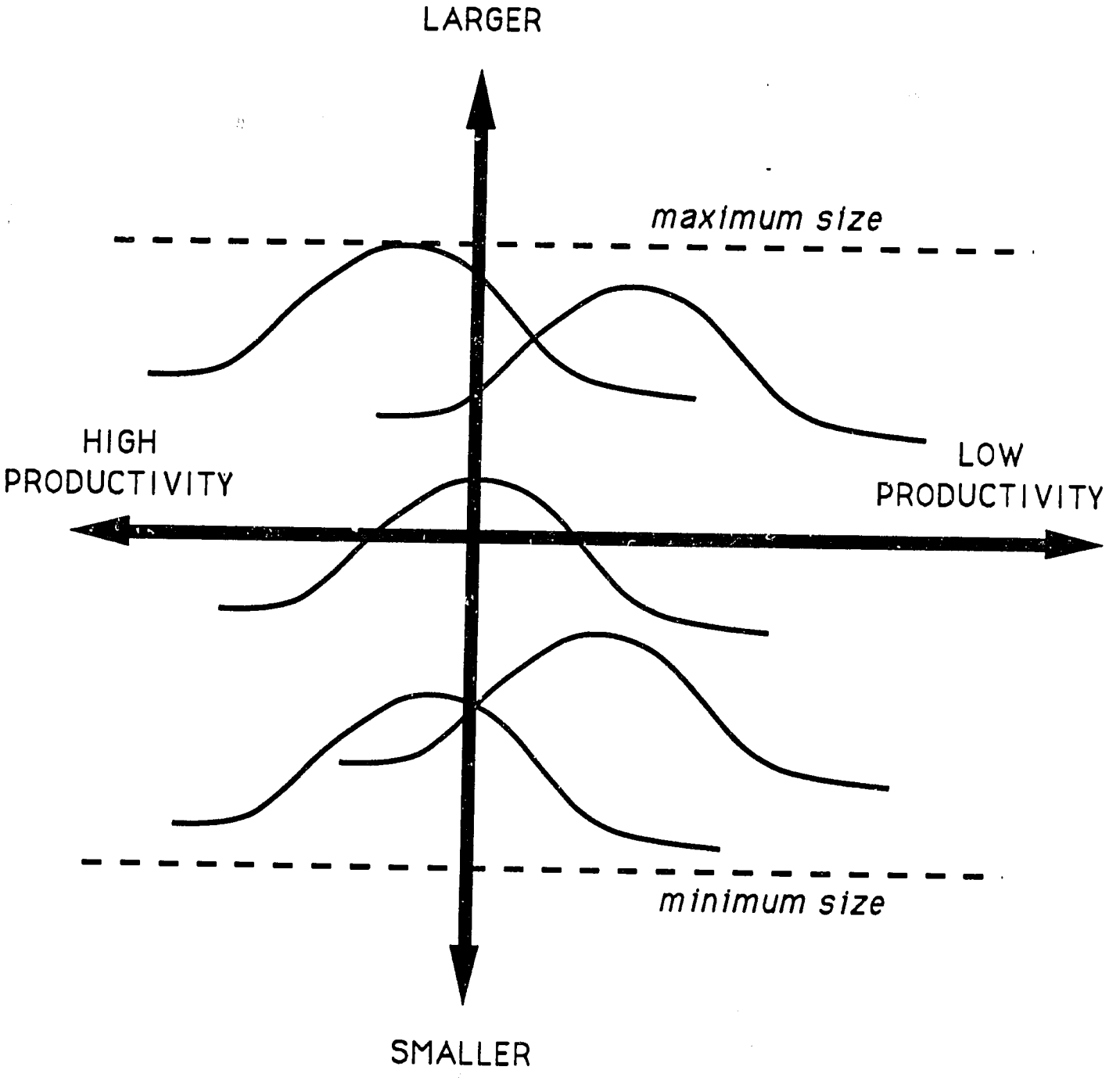
Current Criteria for Merger

- o Size limits
  - maximum size- prevent monopoly
  - minimum size- ensure viability
- o Productivity mix
  - more profitable mines
  - marginal mines

Proposed Measures

- o Potential companies submit merger proposals for government approval
- o More profitable mines submit "negative bids" (subsidies) for less profitable mines

BASIS FOR RESTRUCTURING POLISH HARD COAL INDUSTRY



ADDITIONAL CRITERIA: TARGET COAL QUALITY

o Permits numerous steam coal market "plays"

o Opportunities in steam coal export markets

- low sulfur steam coal into older boilers not economic for FGD (flue gas desulfurization, or "scrubbers")

- mid- to high volatile metallurgical coal into steam boilers with tighter environmental standards

- higher sulfur steam coal into boilers with existing/new FGD

- coal blending to meet various specifications

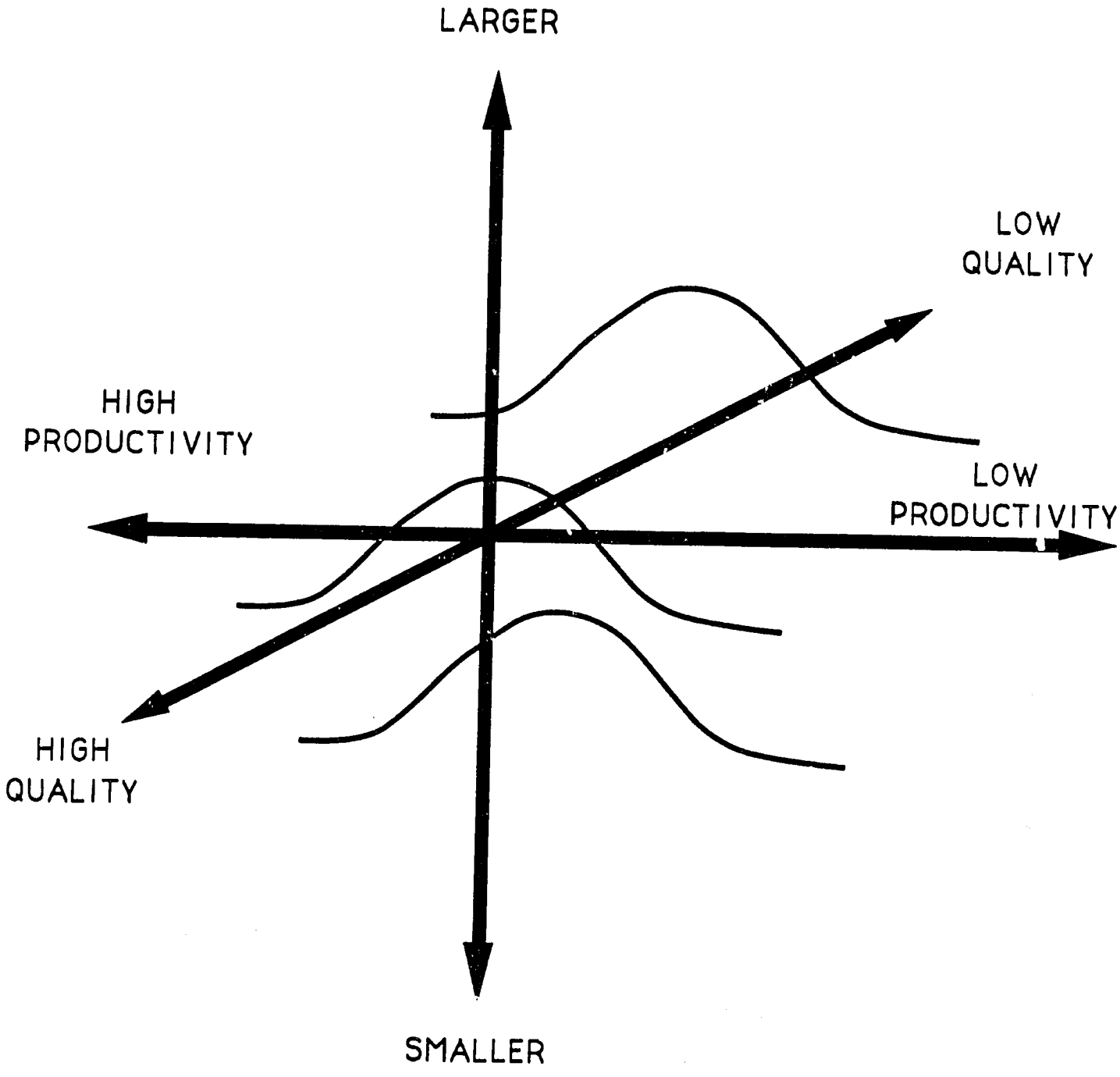
Advantages of Coal Quality Focus

o Allows concentration of production investment (coal preparation, blending facilities)

o Matches resources to market opportunities

o Structured more naturally like Western business venture

BASIS FOR RESTRUCTURING POLISH HARD COAL INDUSTRY



OVERVIEW OF THE ARGUMENT

- o Current trends in world coal trade reinforce regional (rather than global) markets

- o New Asian coal stays in Asia.

- o European demand opportunity: environmental shift away from high sulfur coals.

- o Price premiums for low sulfur coals in European market will widen.

- o Lesson from fuel switching in America: coal quality is critical to boiler economics.

- o Future profitability of new Polish mining companies may well depend on coal quality.

IS THERE A "WORLD" COAL MARKET?

o Today's market is a world market:

- Australian coal to Europe;
- Western U.S. coal to Spain;
- Indonesian coal to Florida.

o Towards 2000, trends support regional markets:

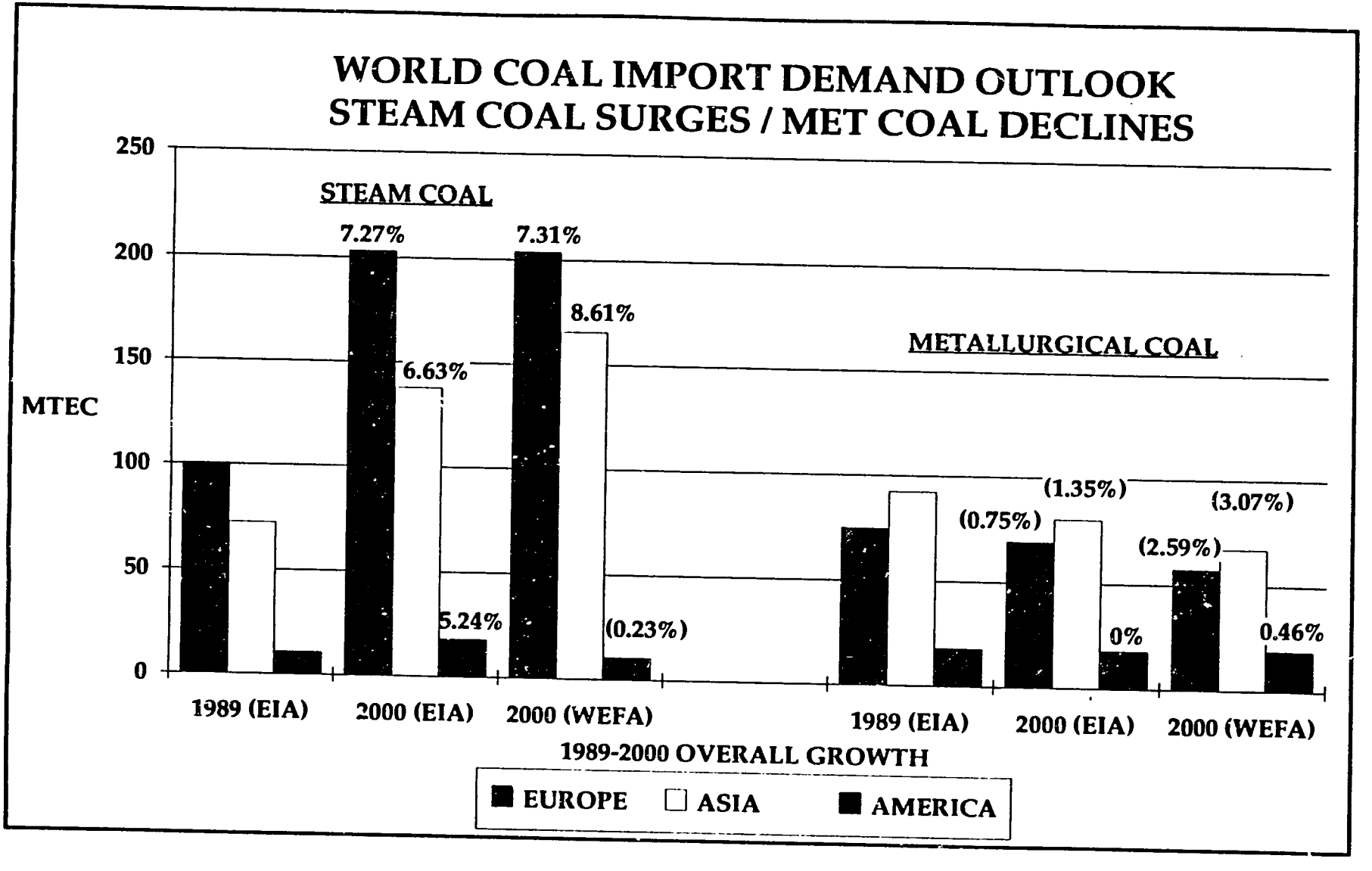
- regional trade agreements;
- regional financing;
- common industrial and environmental policies;
- cooperation in transportation infrastructure.

o Still, prices will be constrained by world low-cost producer:

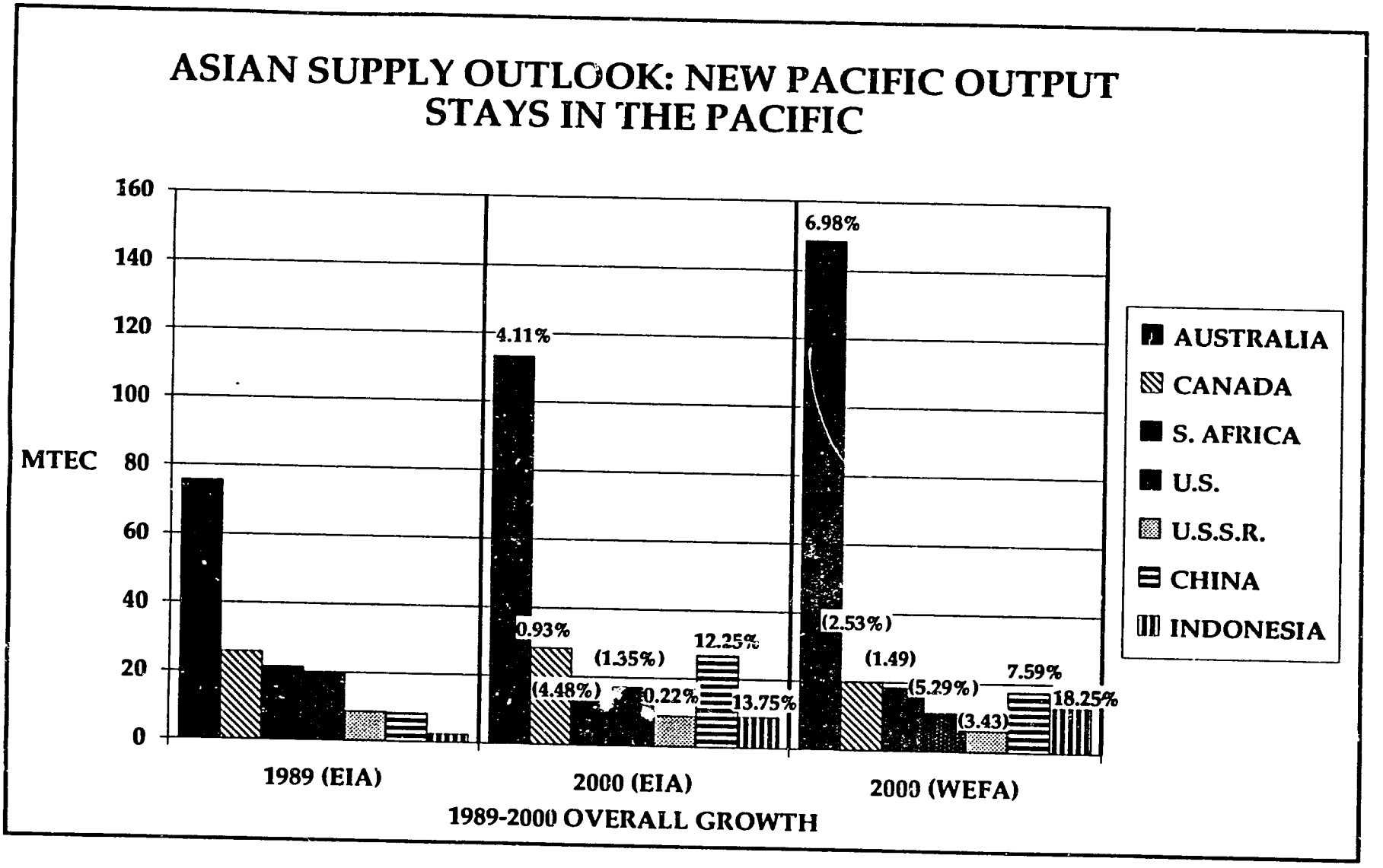
- Chinese steam coal to Japan;
- S. American steam coal to Europe;
- Canadian coking coal.

o Coal serves a critical role in stabilizing world energy markets.

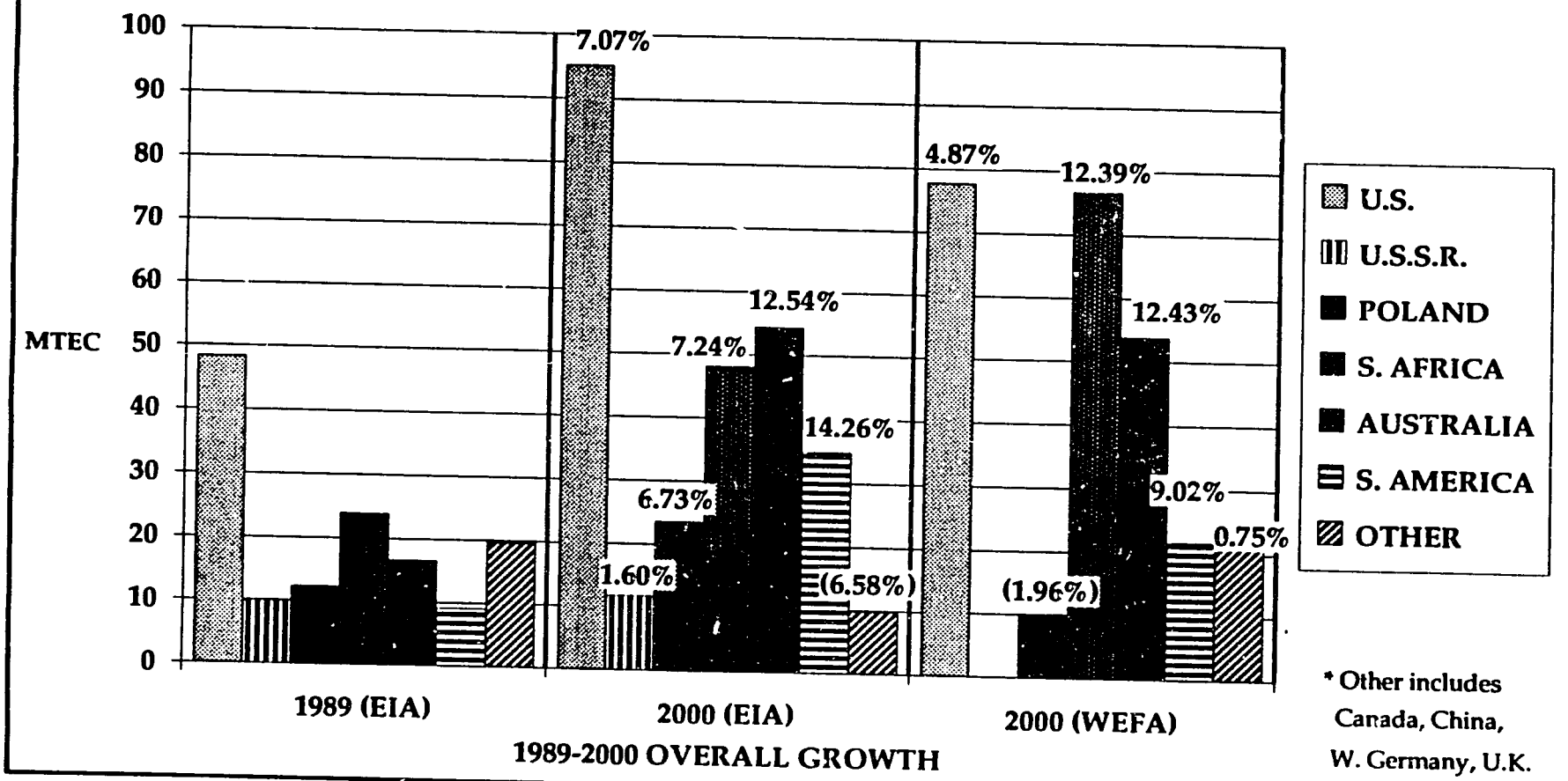
o Can coal compete on total social cost basis?


WORLD COAL IMPORT DEMAND OUTLOOK
STEAM COAL SURGES / MET COAL DECLINES
MTEC
250
200
150
100
50
0
STEAM COAL
7.27%
6.63%
5.24%
7.31%
8.61%
(0.23%)
METALLURGICAL COAL
(0.75%)
(1.35%)
0%
(2.59%)
(3.07%)
0.46%
1989 (EIA)
2000 (EIA)
2000 (WEFA)
1989 (EIA)
2000 (EIA)
2000 (WEFA)
1989-2000 OVERALL GROWTH
EUROPE
ASIA
AMERICA

162


ASIAN SUPPLY OUTLOOK: NEW PACIFIC OUTPUT STAYS IN THE PACIFIC
MTEC
160
140
120
100
80
60
40
20
0
4.11%
0.93%
(1.35%)
(4.48%)
0.22%
12.25%
13.75%
6.98%
(2.53%)
(1.49)
(5.29%)
(3.43)
7.59%
18.25%
1989 (EIA)
2000 (EIA)
2000 (WEFA)
1989-2000 OVERALL GROWTH
AUSTRALIA
CANADA
S. AFRICA
U.S.
U.S.S.R.
CHINA
INDONESIA

EUROPEAN SUPPLY OUTLOOK: WILL EASTERN EUROPE STAY IN THE GAME?



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HARD COAL PRICE FORMATION: Theory

Steam Coal Market Segmentation

- o Coal quality segments determined by:
  - Boiler specifications
  - Environmental regulation
- o Transportation corridors

HARD COAL PRICE FORMATION: Theory

Short Term: Demand Driven Prices

- o Excess capacity means "too many suppliers chasing too few customers", i.e., flat supply curve.

- o Prices determined by incremental utility coal demand relative to contractual commitments.

- o Incremental coal demand is a function of:

  - generating unit availability of non-fossil sources;

  - delivered prices of competitive alternative fossil fuels.

- o Short term coal price is bounded by operating cost of suppliers in:

  - specific quality segment;

  - accessible to transportation corridor.

HARD COAL PRICE FORMATION: Theory

Long Term: Supply Driven Prices

o Excess supply eliminated through closure of inefficient mines

o Prices determined by the:

- cost of additional mine capacity; and
- timing of these capacity additions relative to demand.

o Timing of mine capacity additions determined by expectations relative to:

- generating capacity expansion;
- trends in fuel prices.

o Cost of mine capacity is set by:

- technology change.
- factor productivity growth.

HARD COAL PRICE FORMATION: Practice

Domestic Steam Coal Markets

- o Vast majority of coal purchased under contract
- o Price set in competitive bidding for contracts on FOB mine basis
- o Types of contracts:
  - Fixed tonnage
    - - base price plus escalation
    - - cost plus fixed fee
    - - evergreen (market reopener)
  - Variable tonnage
    - - requirements
- o Buyer generally negotiates transportation arrangements separately
- o Pricing Example, including all pricing components (on the board)

HARD COAL PRICE FORMATION: Practice

World Steam Coal Markets

- o Price-setting in world coal markets primitive by oil trading standards
- o Vast majority of purchases through cartelized buyers, (the Japanese Steel Mills, or JSM, etc.)
- o Use of benchmark price-setting
- o Most coal purchased FOB port
- o Little spot buying (annual contracts)
- o Only accounting for coal quality at present is low sulfur premium in steam market

LIGNITE PRICE FORMATION: PRACTICE

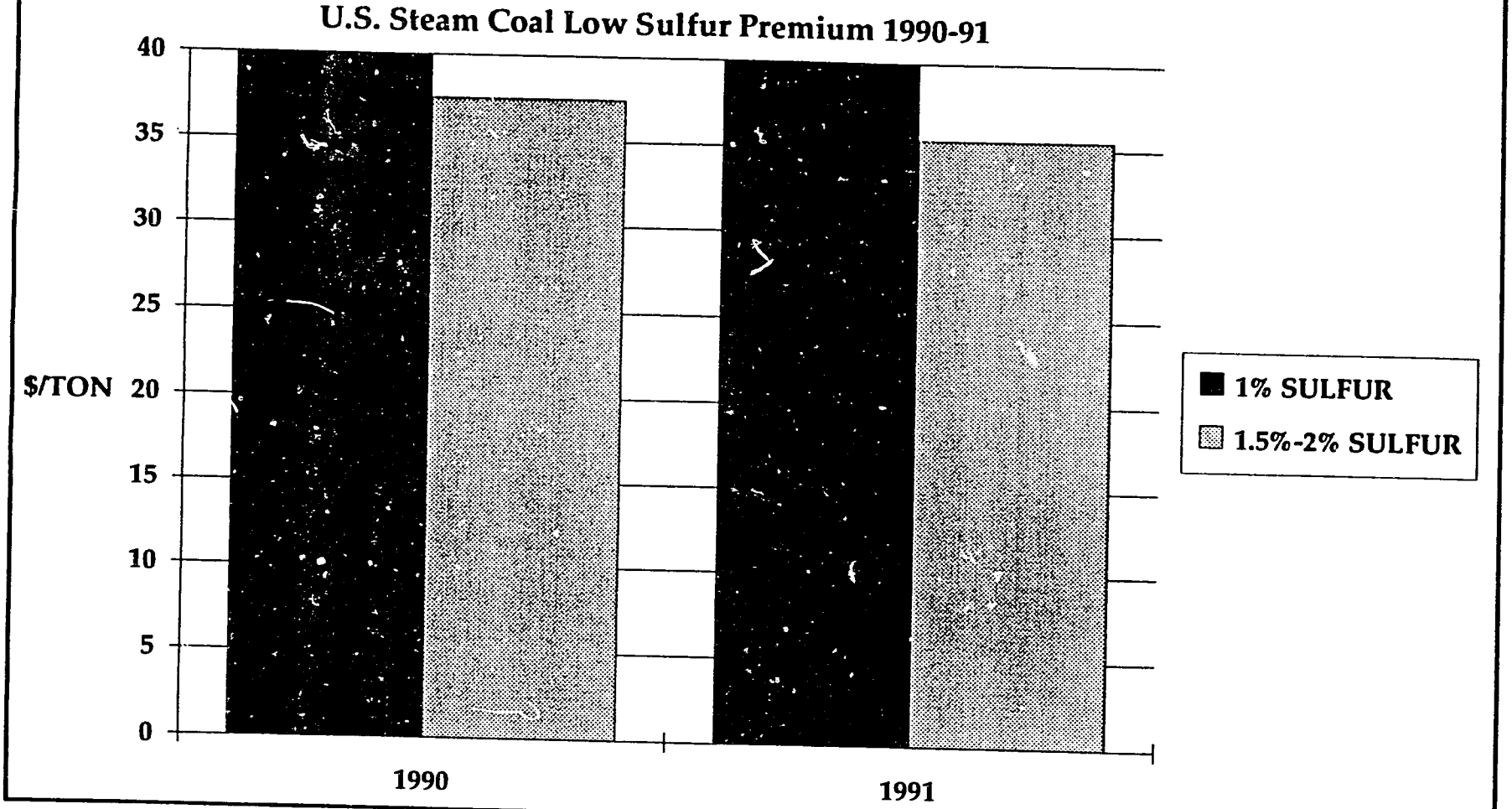
- o Lignite does not trade on the market in United States.

- o All lignite production either captive (owned by buyer) or dedicated reserves with cost plus pricing.

- o Lignite shipped by conveyor belt or short haul truck.

- o Economics dictate domestic utilization, perhaps in tandem ownership with generating company.

DOES THE EUROPEAN MARKET REWARD QUALITY?



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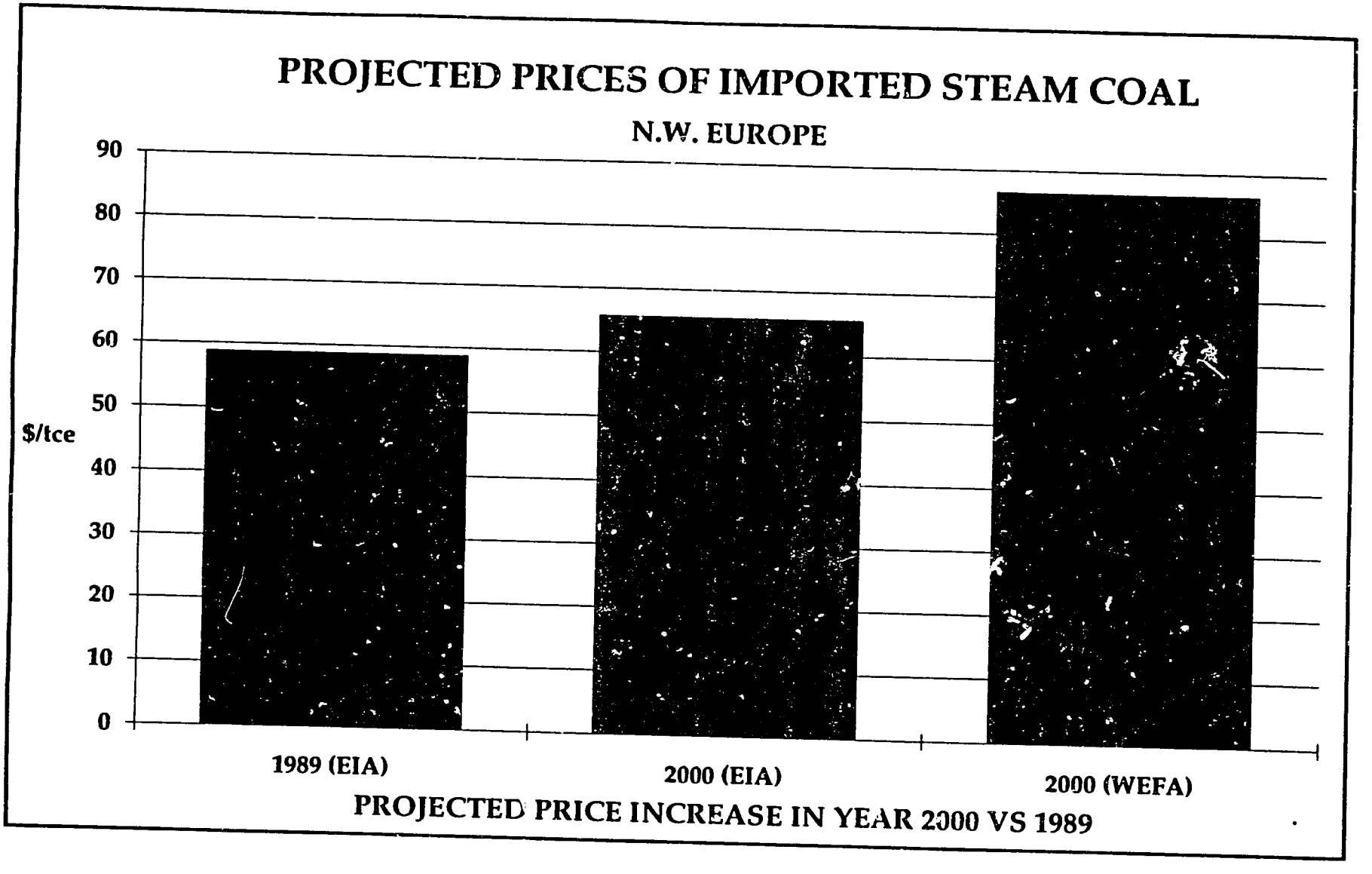
PROJECTED PRICES OF IMPORTED STEAM COAL
N.W. EUROPE
$/tce
90
80
70
60
50
40
30
20
10
0
1989 (EIA)
2000 (EIA)
2000 (WEFA)
PROJECTED PRICE INCREASE IN YEAR 2000 VS 1989

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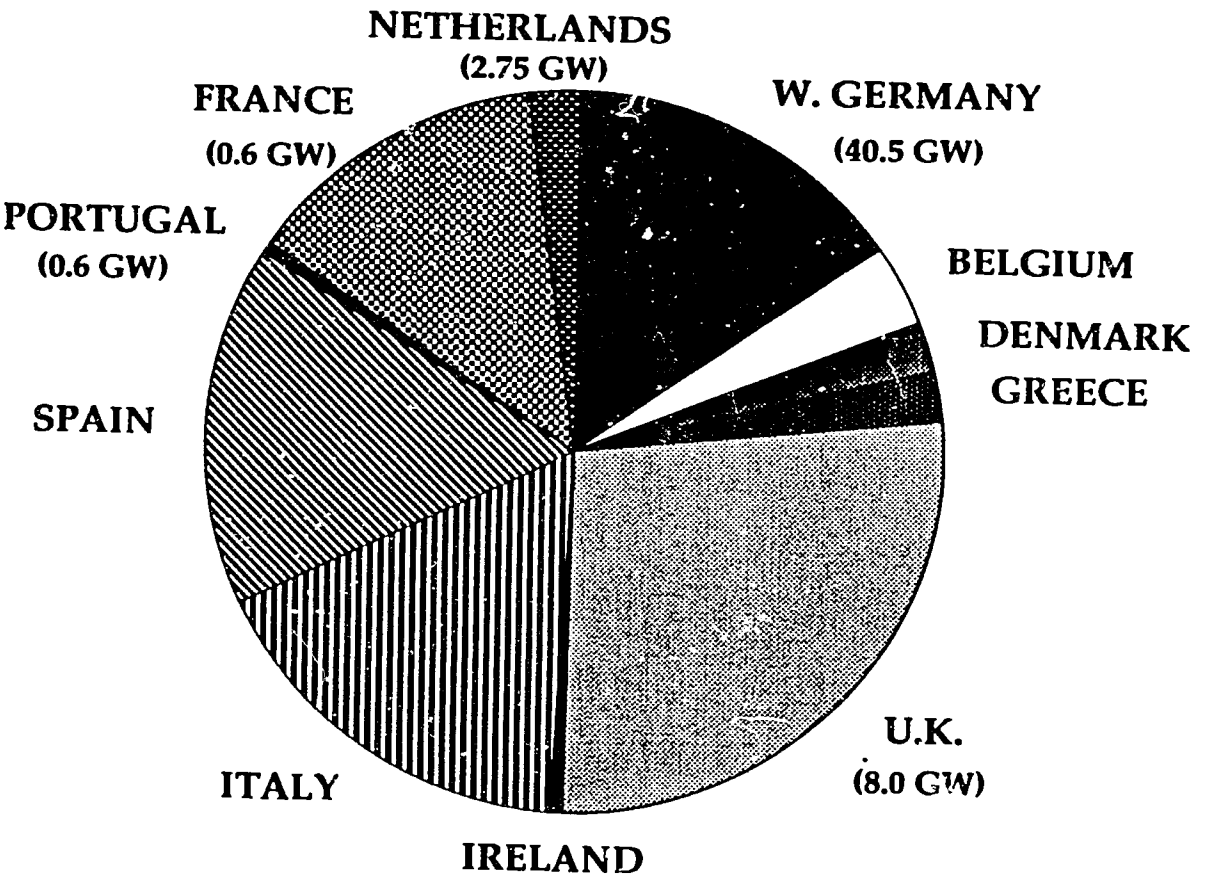
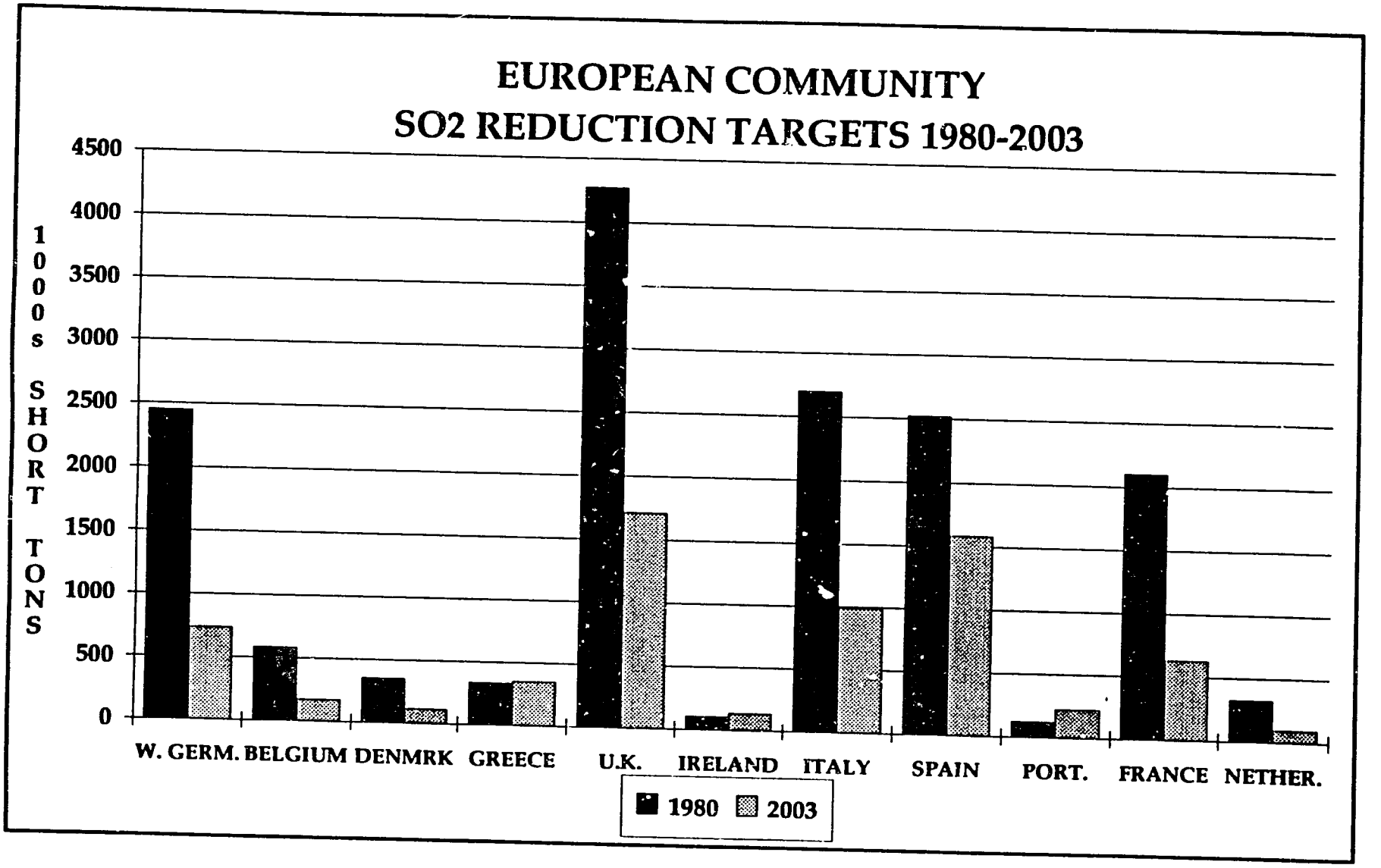
1980 EUROPEAN COMMUNITY SO2 EMISSIONS SHARES vs FGD CAPACITY (INSTALLED/PLANNED)




EUROPEAN COMMUNITY
SO2 REDUCTION TARGETS 1980-2003
1000s SHORT TONS
4500
4000
3500
3000
2500
2000
1500
1000
500
0
W. GERM.
BELGIUM
DENMRK
GREECE
U.K.
IRELAND
ITALY
SPAIN
PORT.
FRANCE
NETHER.
1980
2003

174

	A	B	C	D	E
1	NETBACK VALUATION OF POLISH COAL				
2					
3	Traditional Method (Steam Coal)				
4					
5		U.S. Coal		Colombian Coal	
6	To Rotterdam	Via Newport News		Via Puerto Bolivar	
7					
8		$/mt	$/mmBtu	$/mt	$/mmBtu
9					
10					
11	1. FOBT Price +	$44.00	$1.53	$41.00	$1.55
12					
13					
14	2. Ocean Freight to				
15	Nearby Panamax Port	$6.25	$0.22	$6.25	$0.24
16					
17	Trans-Atlantic CIF Reference				
18	Price -	$50.25	$1.75	$47.25	$1.78
19					
20					
21	3. Freight from Polish Port	$4.00	$0.15	$4.00	$0.15
22					
23	'=Optimum Polish FOB Price	$43.10	$1.60	$43.96	$1.63
24					
25	Heating Value				
26					
27	U.S. Coal	28.7			
28	Colombian Coal	26.5			
29	Polish Coal	26.9			

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NETBACK VALUATION OF POLISH COAL

Alternative: Busbar Cost Basis (Steam Coal)

Method:

- o Calculate production cost of electricity (cents/kilowatthour) using average generating unit heat rates.
- o Adjust heat rates for coal quality parameters (sulfur & ash).
- o Assume quality differences cause Colombian coal to be 5% less efficient than U.S. coal, and Polish coal to be 5% more efficient.

	U.S. Coal Via Newport News (@10,000 Btu/kwh)		Colombian Coal Via Puerto Bolivar (@10,500 Btu/kwh)	
	$/mmBtu	c/kwh	$/mmBtu	c/kwh
Trans-Atlantic CIF Reference Price	$ 1.75	1.75	$ 1.79	1.84
Freight from Polish Port *	$ 0.15	0.14	$ 4	0.14
= Optimum Polish FOB Price (Heat Rate Adjusted)	$ 1.69	1.61	$ 1.79	1.70

* : Polish steam coal heat rate assumed 9,520 Btu/kwh.

LESSONS FROM FUEL SWITCHING IN AMERICA

o Coal-fired boilers have much wider tolerance for off-specification coal than originally assumed, (e.g., subbituminous coals.)

o Creates opportunity for exploiting the economics of coal quality.

o Mid- to high volatile content metallurgical coal can command a premium on steam market given tighter standards, (e.g., cyclone boilers)

o Economics of coal preparation have not yet been effectively tapped.

o Must understand the cost-effectiveness of SO_2 (as well as reduction measures for other pollutants.)

CLEAN AIR ACT & SO2 ALLOWANCES

o Acid rain legislation in America passed after decade-long debate.

o Market-based approach to environmental regulation.

o No emission limits; emissions controlled by issuances of finite number of "allowances" to pollute which are reduced over time.

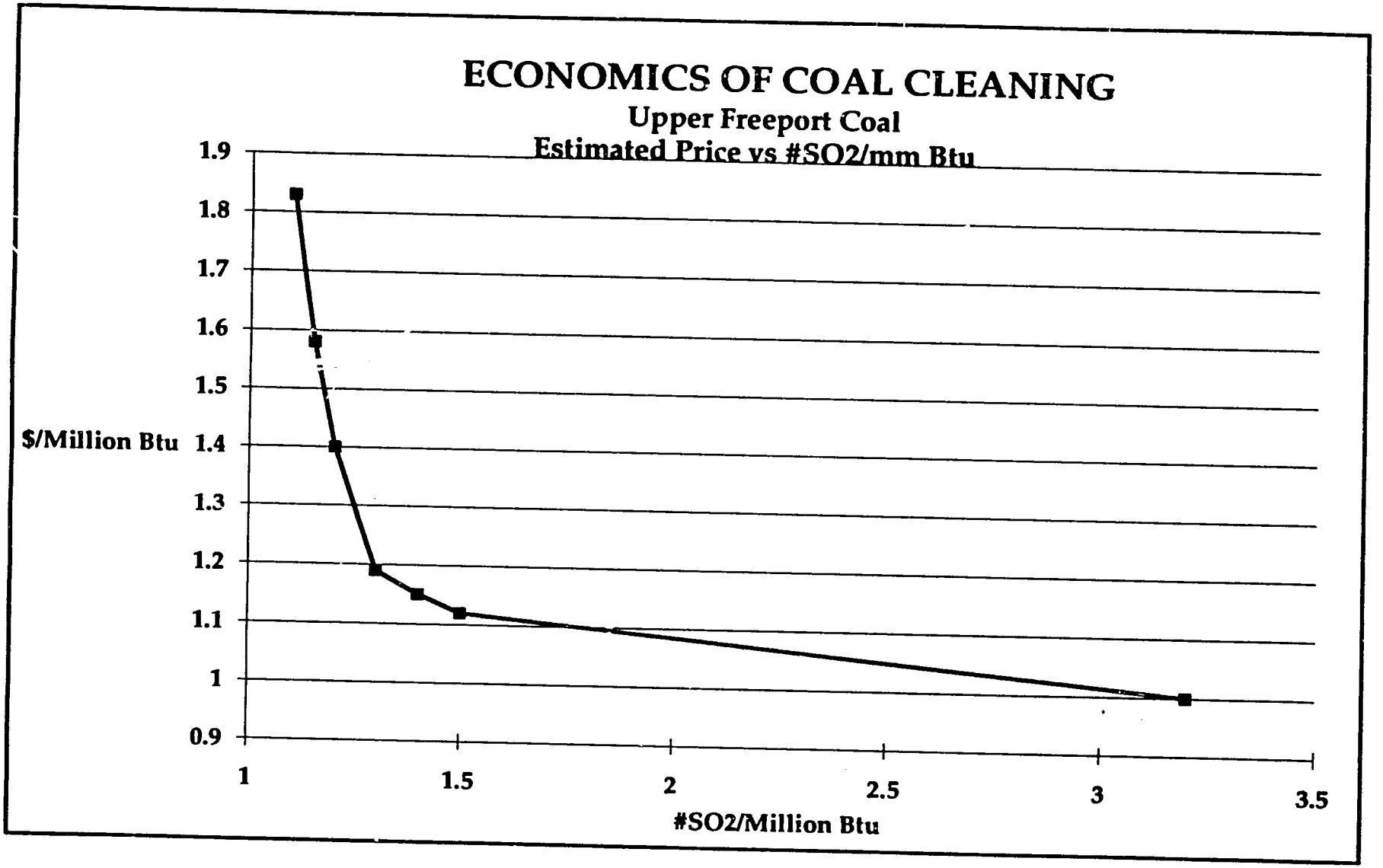
o Those who are more efficient at controlling SO_2 may overcontrol and sell their excess allowances.

o In ideal market, no company would spend more than the market price for control measures.

Reasons to Understand Allowances

o Valuable insight into sources of value in fuel markets in environmental terms.

o Wave of the Future: CO_2 Allowances?


ECONOMICS OF COAL CLEANING
Upper Freeport Coal
Estimated Price vs #SO2/mm Btu
$/Million Btu
1.9
1.8
1.7
1.6
1.5
1.4
1.3
1.2
1.1
1
0.9
1
1.5
2
2.5
3
3.5
#SO2/Million Btu

BUYING COAL QUALITY: Make Way for Economic Dispatch

o Will markets appropriately value coal quality?

o Trends in steam coal sector suggest the market will:

- increasing concern for environmental impact leading to compulsory demand for better coals;

- elimination of subsidies in fuels/generation;

- increasing competition in electricity generation.

o What must be done?

- busbar cost evaluation of fuel purchases and economic dispatch;

- increased testing of alternative coals/ and other fossil fuels;

- further analysis of coal preparation/ coal blending economics.

SUMMARY: Anticipating the Evolving Market

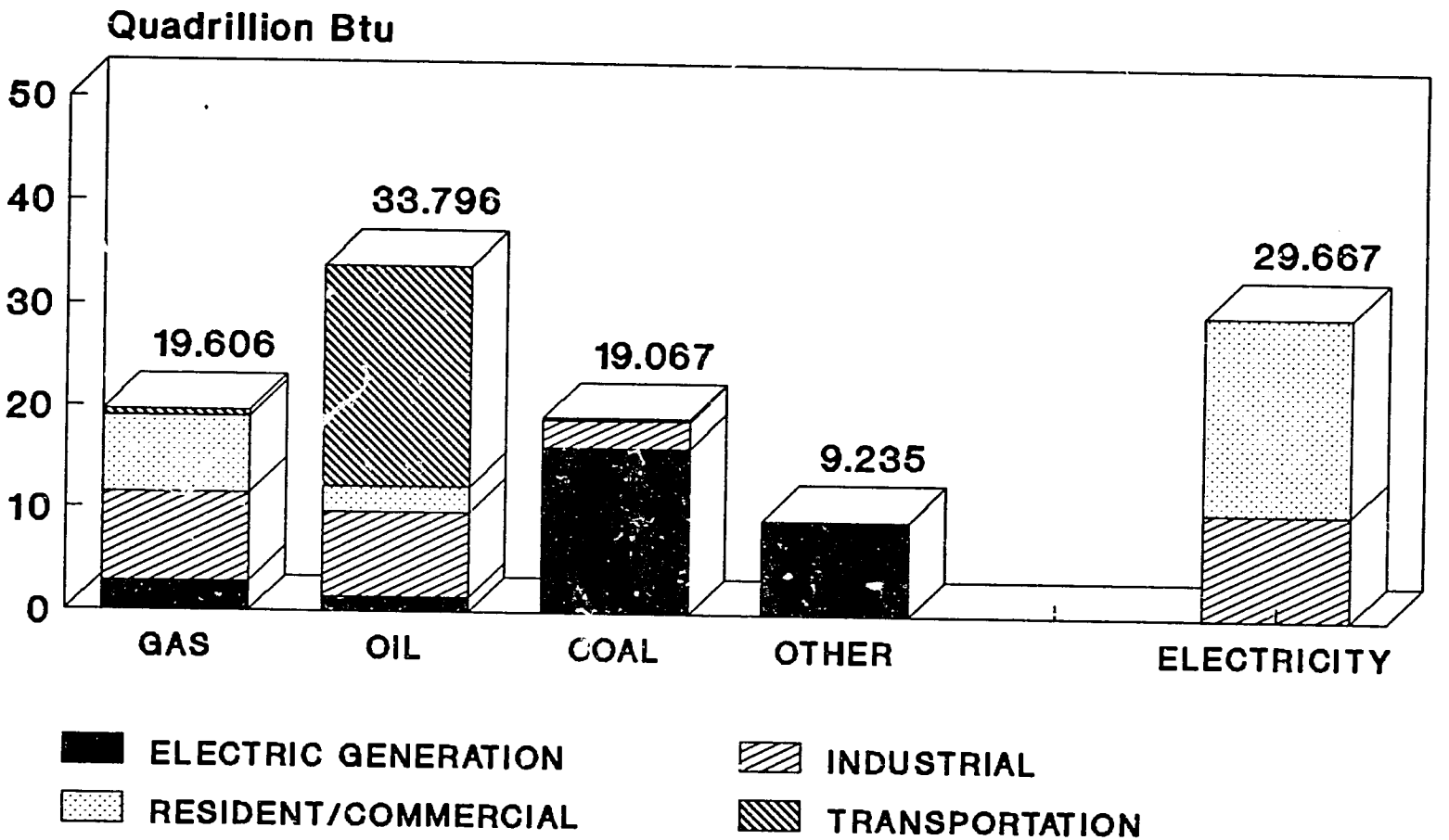
o Focus mining, marketing, and sales resources on market opportunities.

o Work with your customers on boiler economics of coal quality, both domestically and internationally.

o Understand the economics of sulfur dioxide reduction, both through fuels and technology.

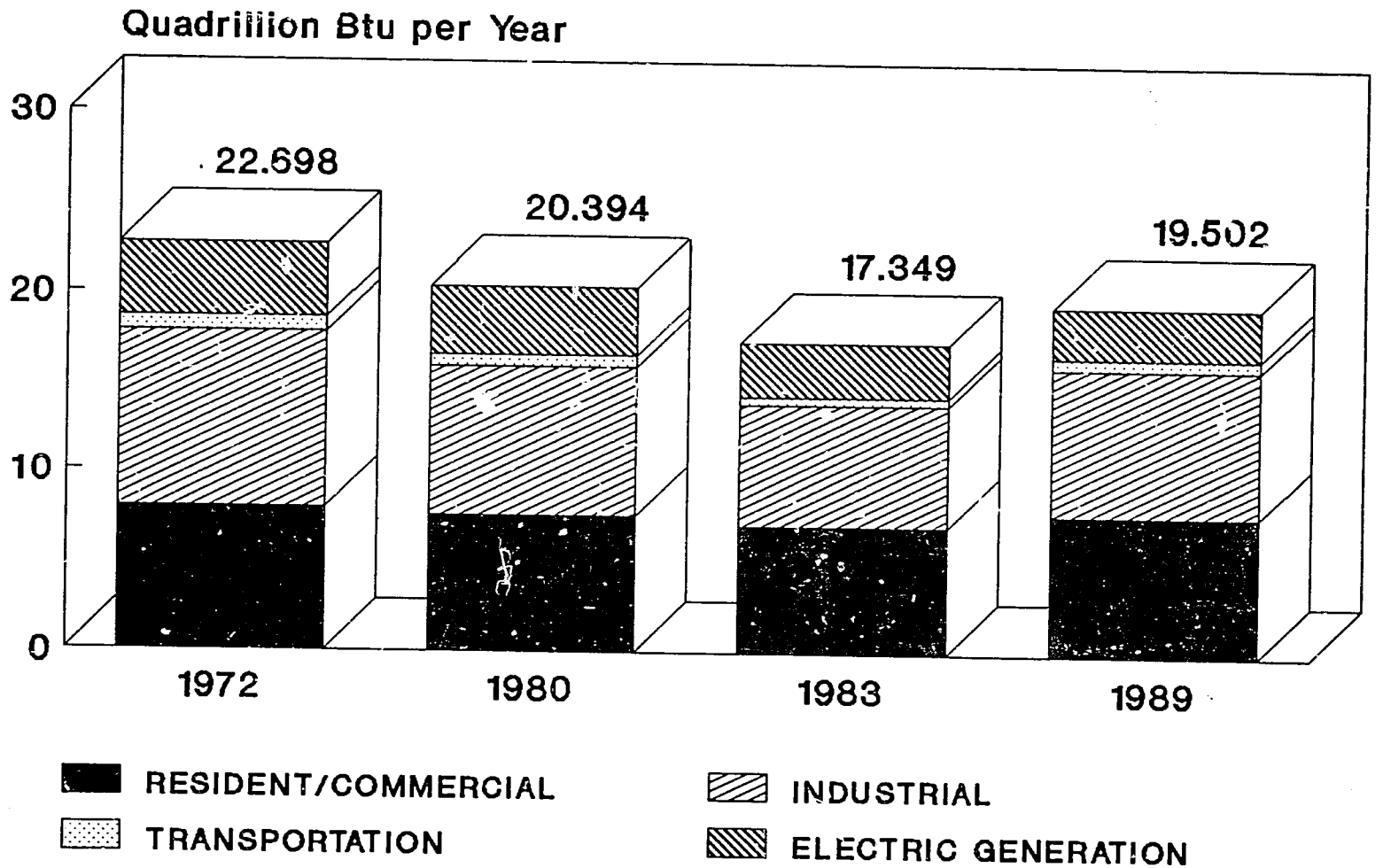
o Provide for economic allocation of fuels domestically.

GAS PROVIDED 24% OF U.S. ENERGY IN 1990
Data for Period: Dec. 1989 - Nov. 1990



SOURCES: BSA, Inc.
EIA Monthly Energy Review, Feb. 1991

BREAKDOWN OF GAS DEMAND: 1972-1989



Sources: BSA, Inc.;
EIA Monthly Energy Review, Feb. 1991

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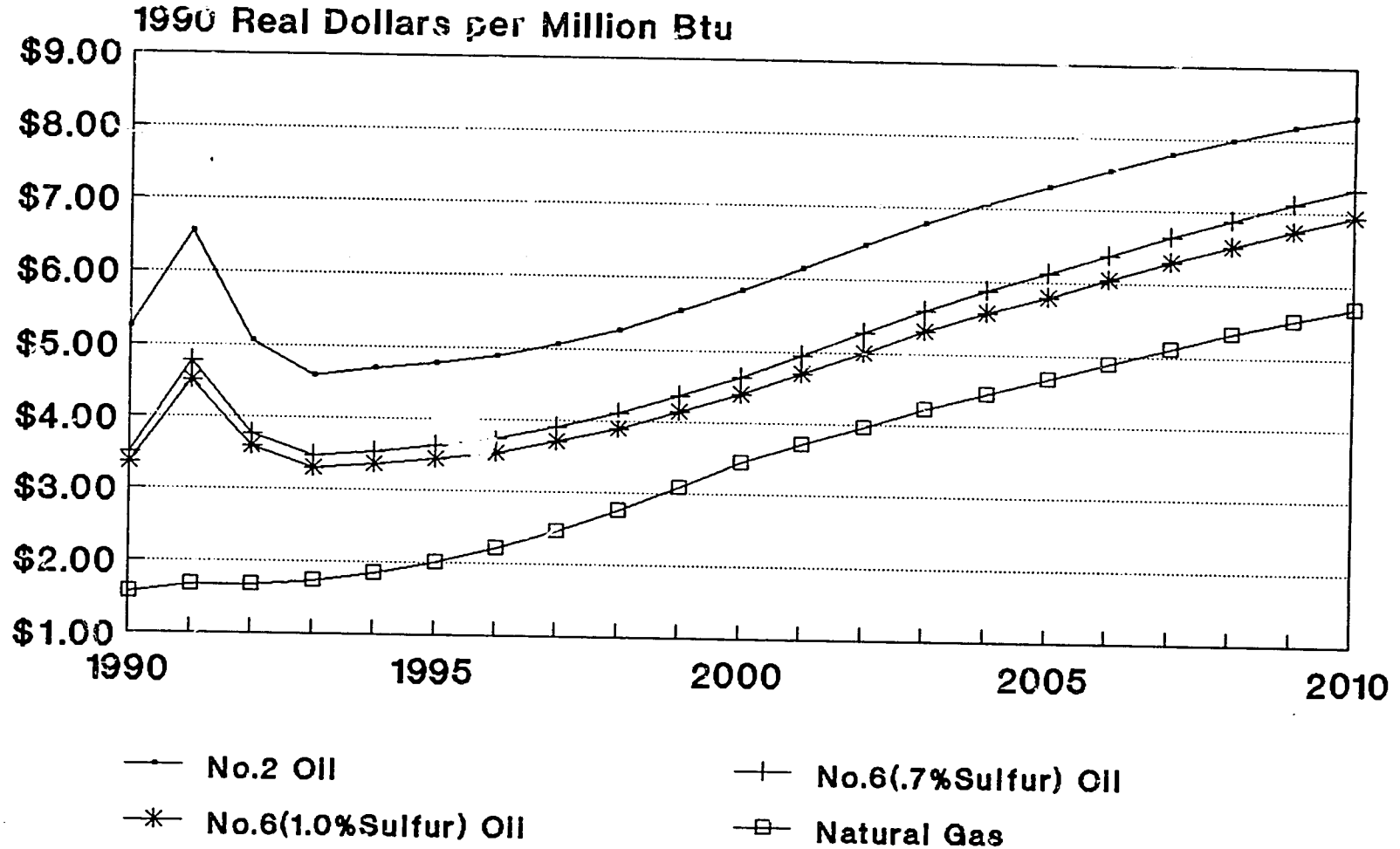
FORECAST OF OIL AND GAS PRICES



Sources: BSA, Inc.;
Data Resources, Inc., 1990

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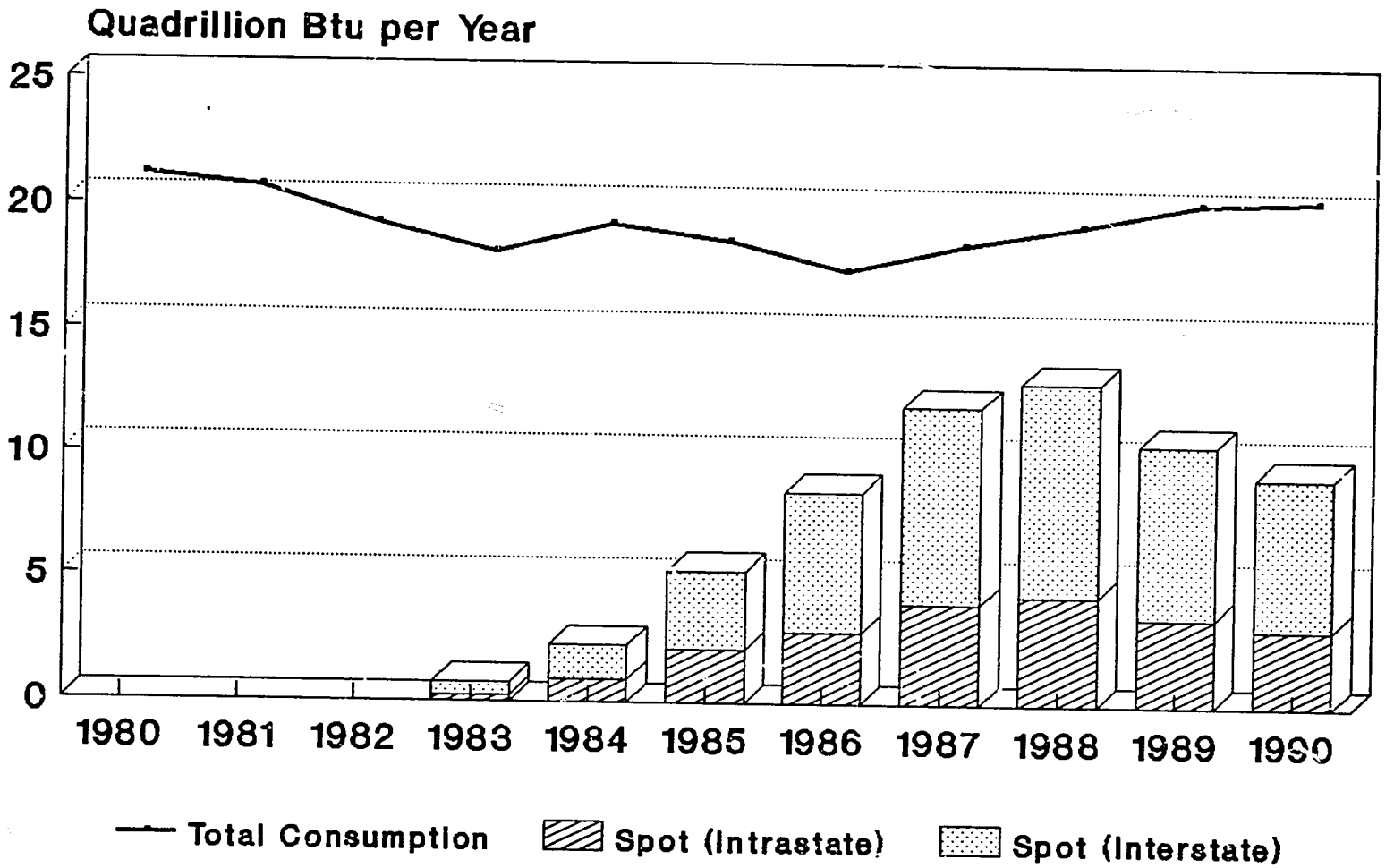
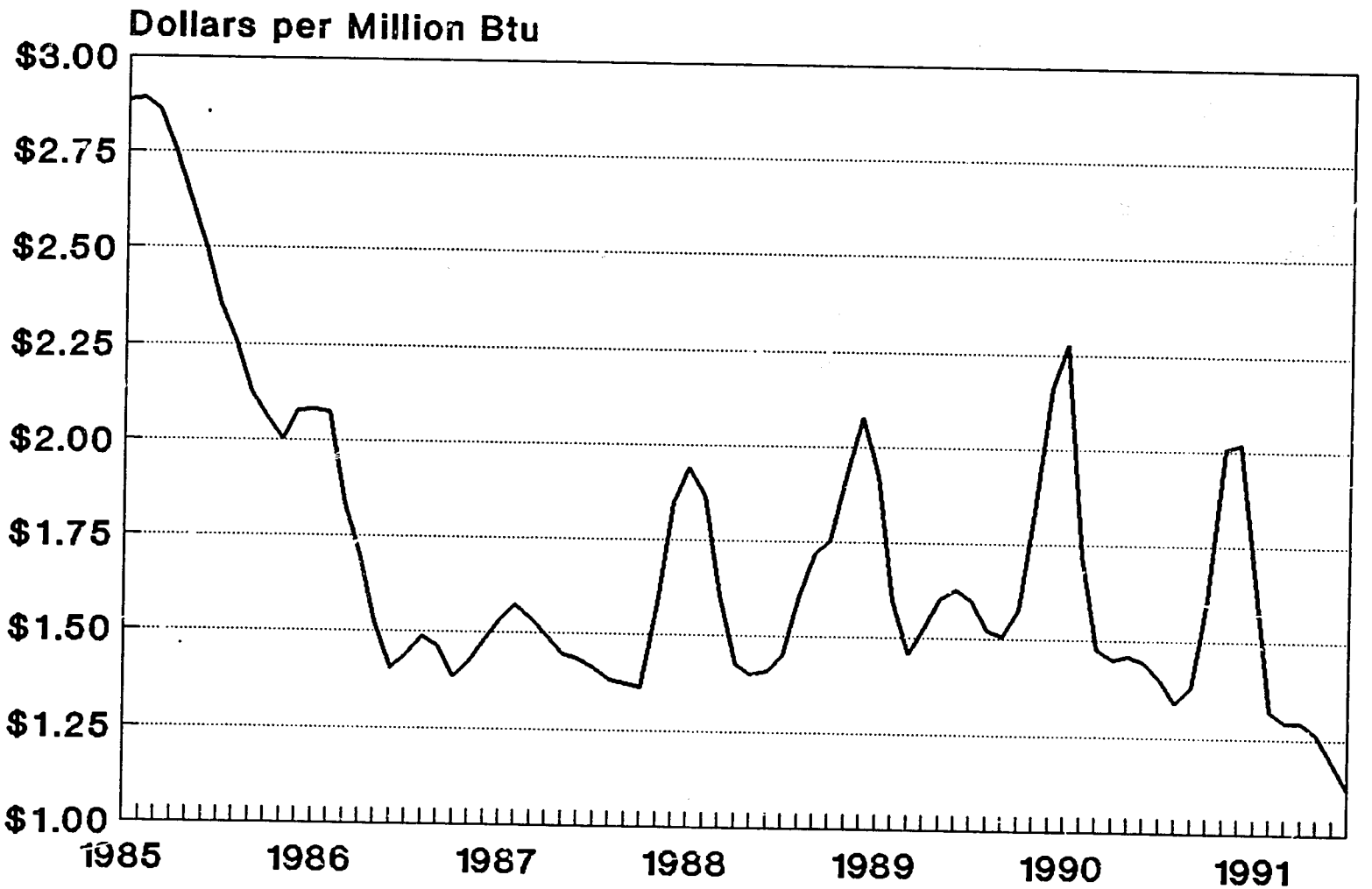
SPOT MARKET SHARE OF TOTAL CONSUMPTION
1980 through 1990



Source: BSA, Inc., 1990

LOUISIANA GULF ONSHORE WELLHEAD SPOT
January 1985 - July 1991



Sources: BSA, Inc.; Natural Gas Week

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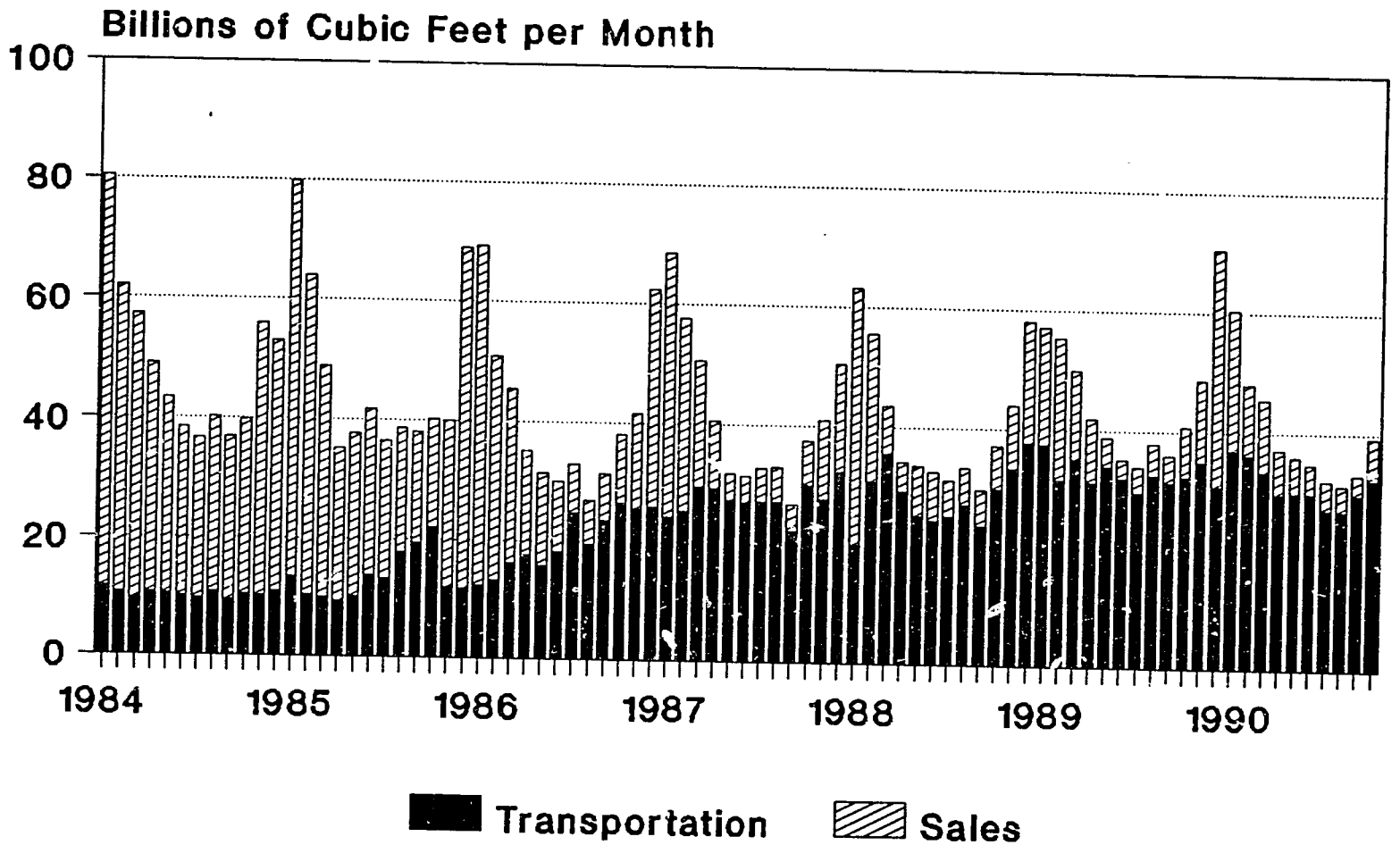
SOUTHERN NATURAL THROUGHPUT VOLUMES
January 1984 - October 1990



Sources: BSA, Inc.;
EIA Natural Gas Monthly

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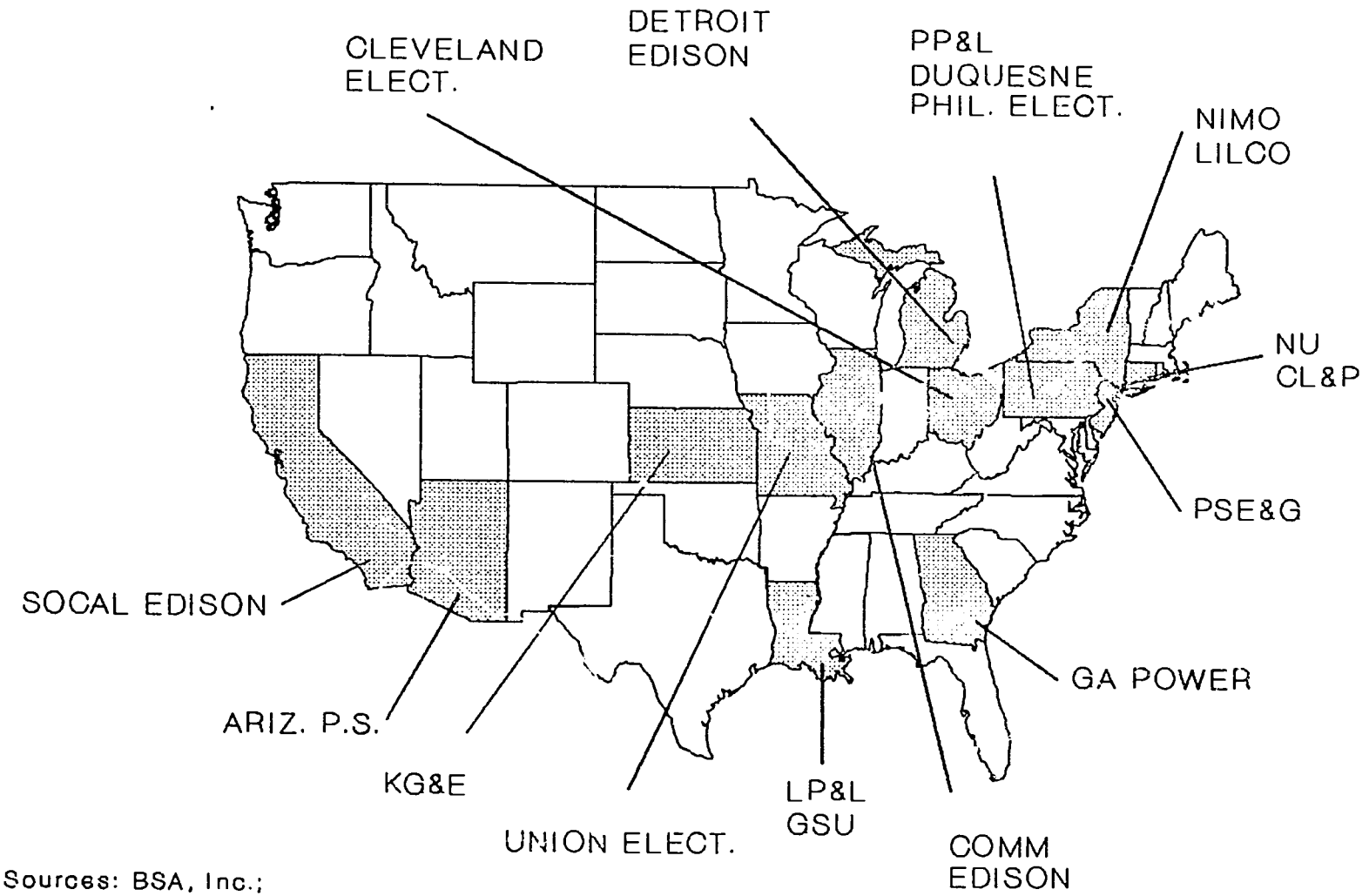
UTILITY NUCLEAR PLANT DISALLOWANCES



Sources: BSA, Inc.;
Public Utilities Fortnightly, Feb. 1, 1991

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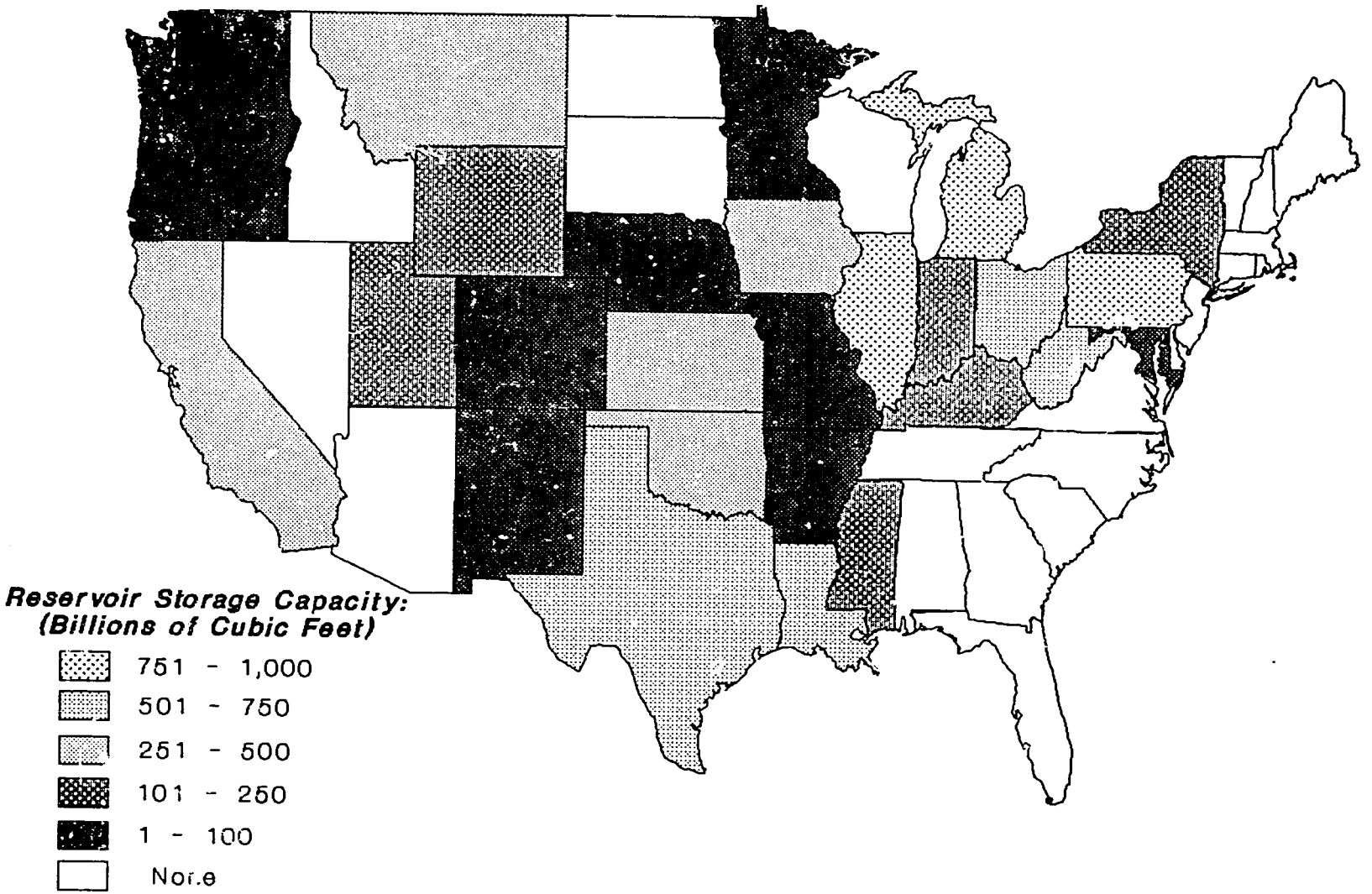
UNDERGROUND NATURAL GAS STORAGE CAPACITY BY STATE



Source: "Natural Gas Monthly", February 1991.

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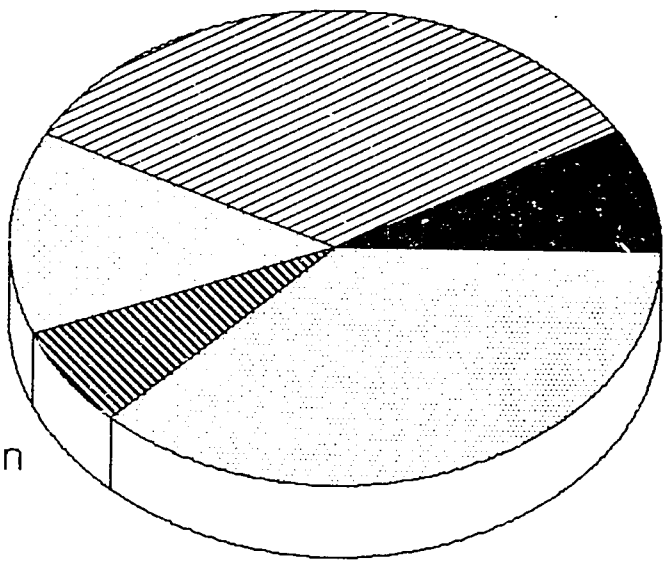
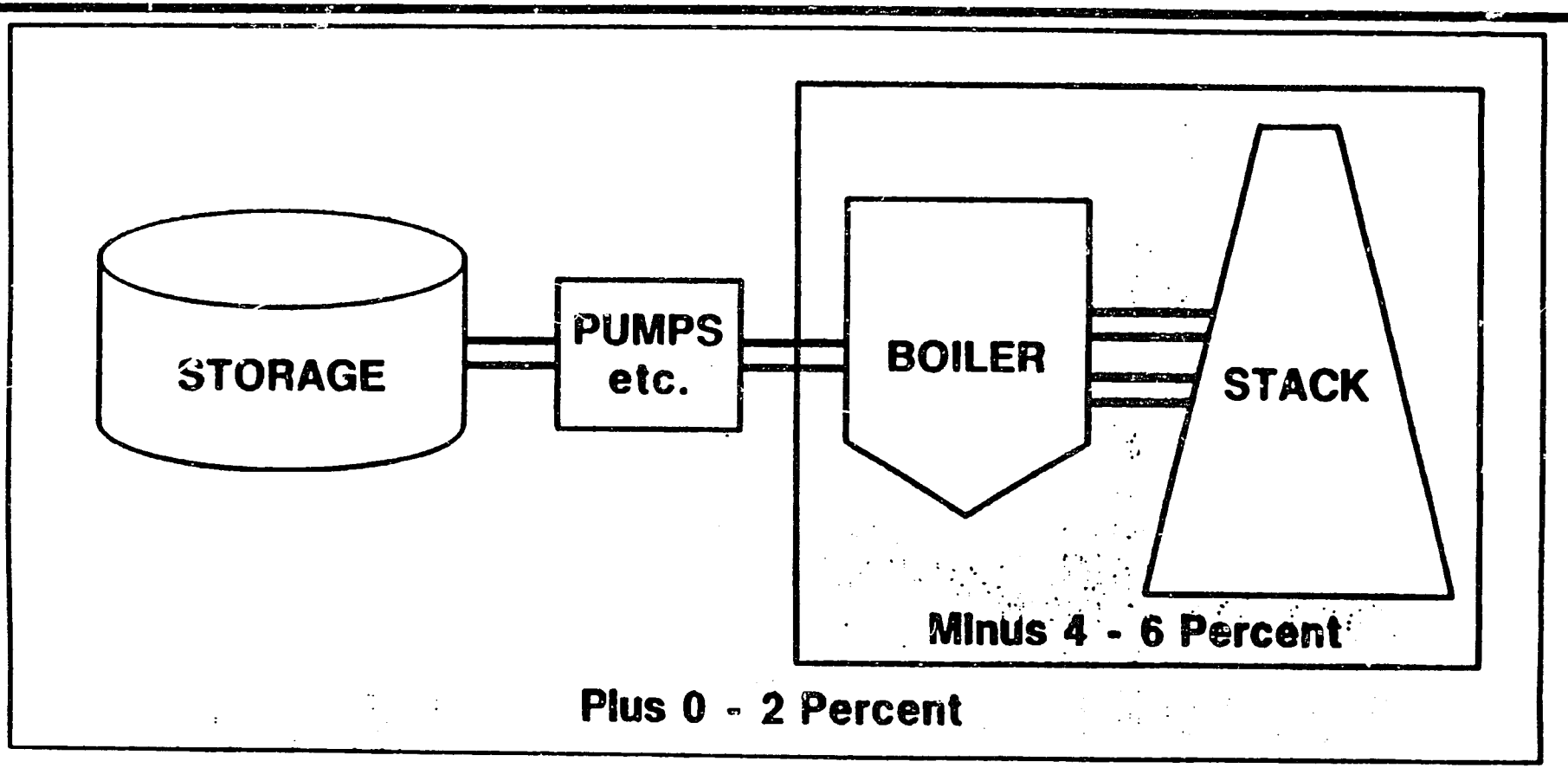
THE U.S. HAS 1,188 TCF OF NATURAL GAS
(Trillions of Cubic Feet, Tcf)



Sources: BSA, Inc., from U.S. Department of Energy, May 1988

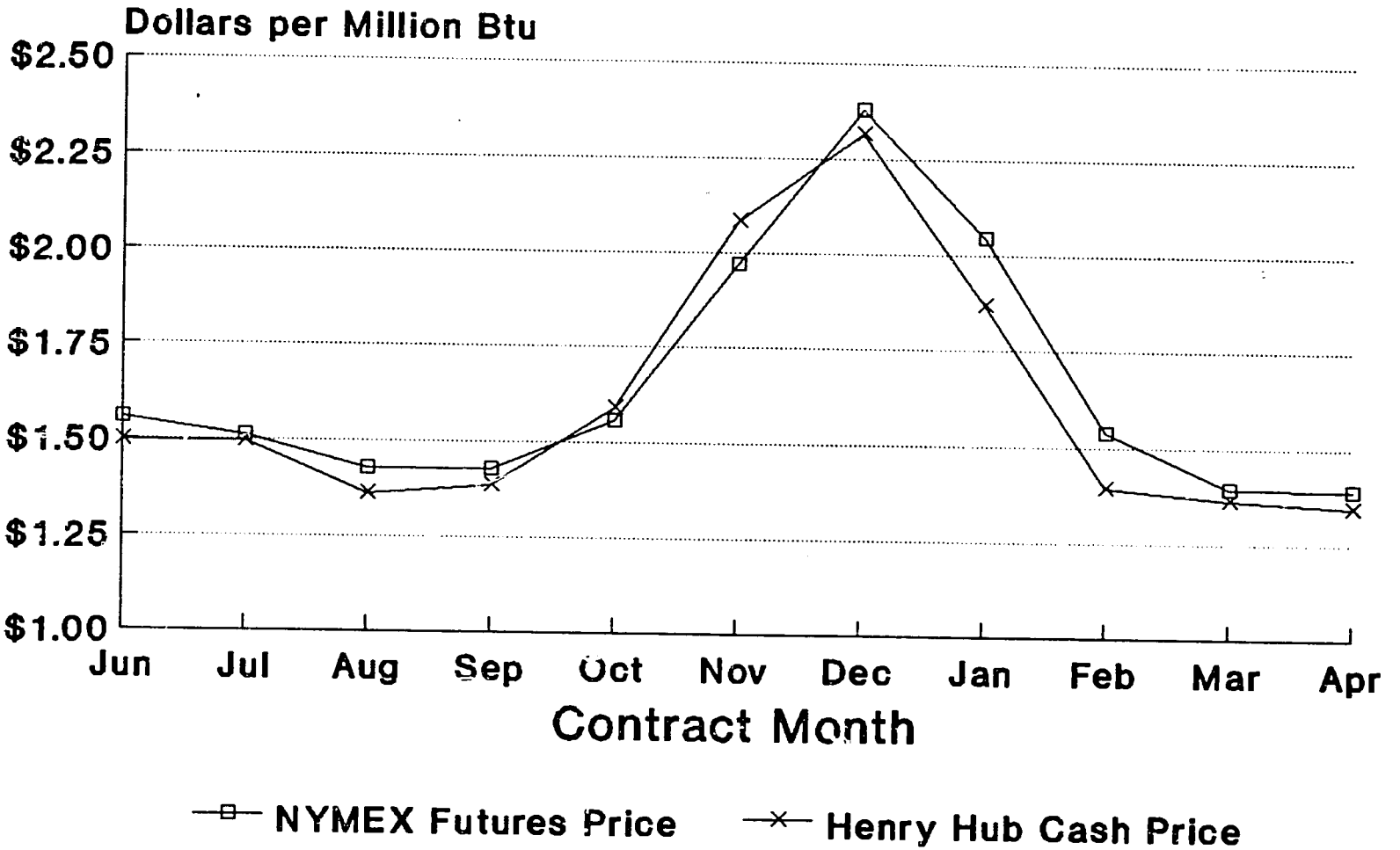
New gas markets . . .

BOILER EFFICIENCY IS ENHANCED BY GAS CONVERSION, IF TOTAL SYSTEM IS CONSIDERED



GAS FUTURES PRICE CONVERGENCE

(Final Cash Bids vs. Futures @ Closing)



Sources: BSA, Inc.; Gas Daily

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ENERGY PRICING ANALYSIS FOR POLAND

Donald I. Hertzmark

September, 1991

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Energy prices should encourage patterns of production and use that will result in the energy production and use yielding the highest possible value to society. This objective can be translated into two general economic criteria:

1. Energy prices should cover the total costs of producing the energy resource, including the benefit to society of depleting the last unit of that energy;

2. Energy prices should lead energy users both to choose the least-cost energy source for a given application and to use energy only as long as the value of the last unit of energy consumed equals or exceeds the cost to society of supplying that unit of energy.

Principles of Efficient Energy Pricing

Energy Prices Should Be Made With The Following In Mind:

1. The cost of producing resources; and
2. Determining the value to the country of different energy resources in various end uses; and
3. Economy-wide effects of energy pricing, including those on income, prices, and foreign trade.

In A Free Market, the Following Relationships Will Hold:

- Price = Long Run Marginal Cost
- P = Marginal benefit of the last unit sold

Complicating The Theoretical Model

- LRMC often is difficult to estimate since it involves imperfect information about not only present but future technology and costs;

- Marginal benefit or marginal value to consumers is a concept which economists, despite many attempts, have not been able to translate into directly measurable terms;

- Energy production often results in costs to society which are not included in LRMC calculations because they are not borne by the producer. These are:

  ✓ Depletion costs for nonrenewable resources; and

  ✓ Environmental externalities such as pollution.

Depletion Allowance

The Depletion Allowance (DV) of a resource accounts for its value in the future when extraction or production will be higher in cost due to the depletion of current reserves. The DV can be estimated, provided one has some idea of the future price of the resource.

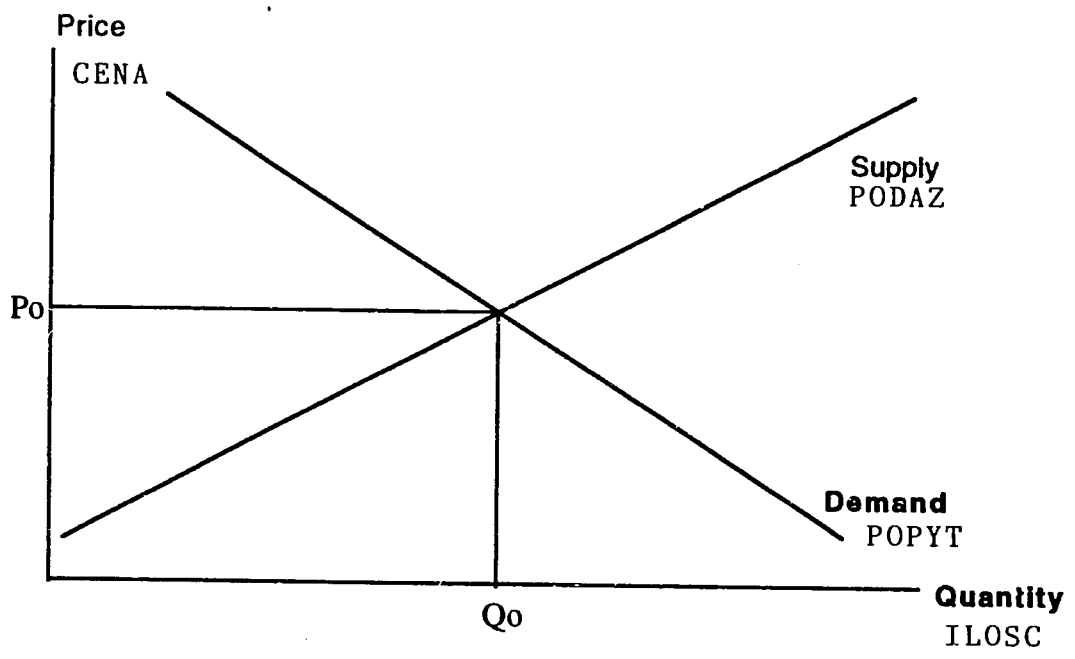

Figure 1: Supply and Demand Equilibrium
ROWNOWAGA POPYTU I PODAZY

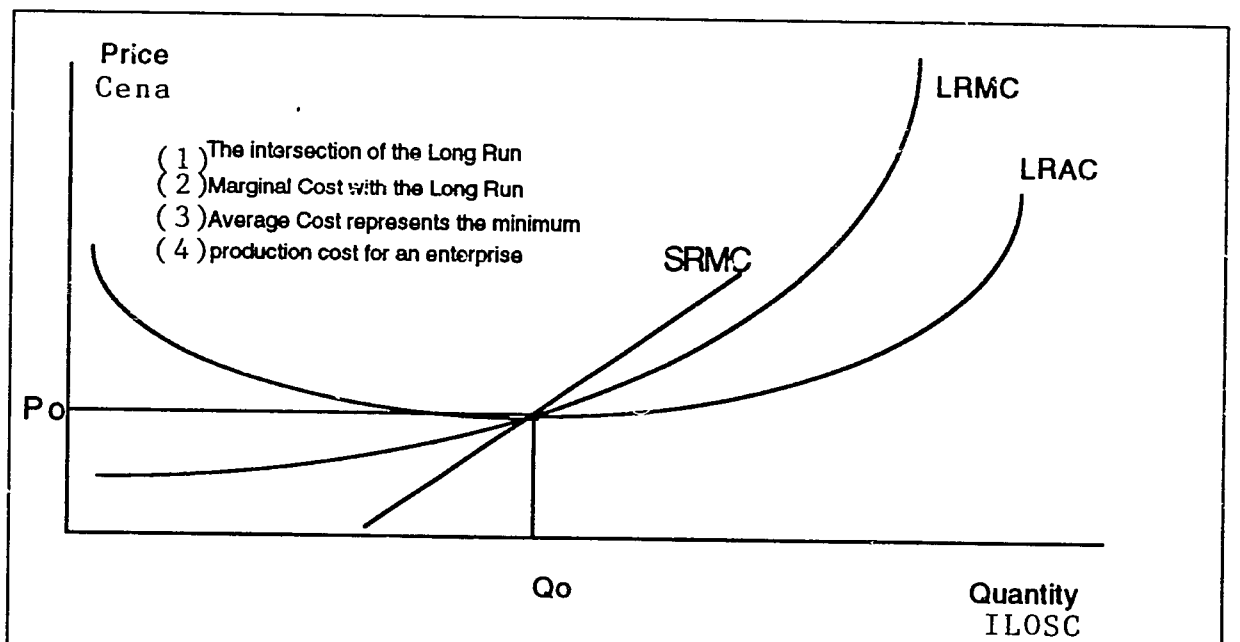

Figure 2: Relationship of Average and Marginal Costs
ZALEZNOSC MIEDZY SREDNIM I MARGINALNYM KOSZTEM

(1) SKRZYZOWANIE DLUGOTERMINOWE
(2) Koszt MARGINALNY DLUGOTERMINOWY
(3) Sredni KOSZT REPRESENTUJE MINIMUM
(4) Koszty PRODUKCJI DLA PRZEDSIEBIORSTWA

i.e.,

$$DV_n = \frac{\text{Economic Price of Backstop Fuel in year of economic depletion}}{(1 + 1)^{T-n}} \quad (3)$$

Economic Rent

Economic rent is the difference between the economic supply cost of a fuel and its market price (if any). Rent can be positive or negative.

A positive economic rent is a market price for a resource which is greater than is necessary to induce production of that resource.

The economic rent is the area between the supply curve and the equilibrium market price. Any area above the equilibrium price but below the demand curve represents consumer's surplus. Figure 3 illustrates the economic rent plus consumers' surplus available to energy producers and energy consumers. The area bounded by O, P_c, C, b reflects the area in which it is in the interests of both consumers and producers to negotiate a selling or purchase price. That is, between P_p and P_c can be found a price which pays for the fuel while at the same time meeting other social or financial objectives.

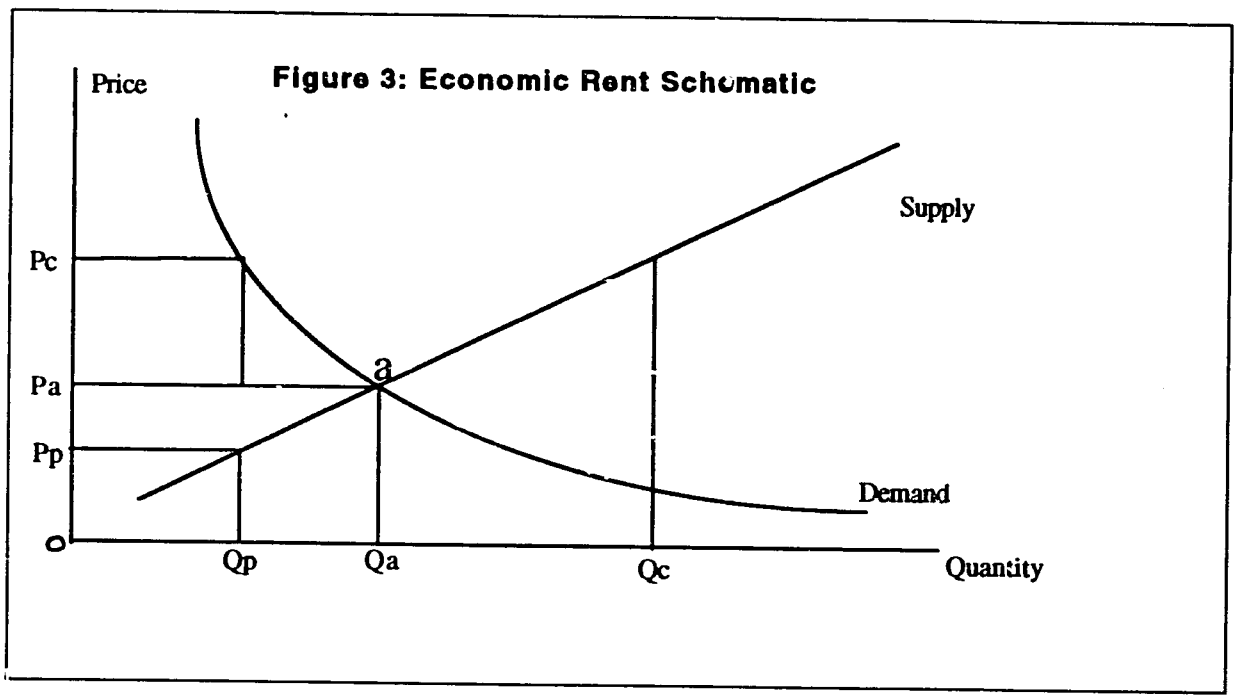

Figure 3: Economic Rent Schematic

Macroeconomic Considerations in Energy Pricing

- Imports of energy and energy using and transforming equipment will probably represent the largest single item on the balance of trade books;

  ✓ This means that the efficient use of energy is crucial to avoidance of balance of payments and trade deficits (c.f., India).

  ✓ So large are the volumes of investment in energy supply and transformation in some countries that industrial policy is, in effect, energy policy (e.g., USSR, Poland, Czechoslovakia).

- In the future much of Poland's energy infrastructure will be financed from abroad without corresponding exports of that energy (except for coal). This places the burden of making the loans repayable on the efficiency of using that energy.

- If the foreign financed incremental energy is not efficiently used then the economy's additional output may not be enough to repay the loan. That is, too much energy is used for each level of output. Determining how much energy is "too much energy" and letting producers and consumers know when they are using the "right amount" is the job of microeconomic policies.

Conclusions:

- Energy pricing is not a magic bullet;
- Efficient energy prices are perhaps necessary for an efficient economy but they are not sufficient. Other conditions must be present, including:

  ✓ Free mobility of other energy and production resources;

  ✓ Prices elsewhere in the economy that reflect relative values and scarcities.

- Appropriate energy prices can be a powerful for the better in a market economy;

- Experience shows that price controls generally lead to costly and sometimes disastrous results - i.e., the risks of bad energy pricing policies are worse than the benefits of good ones.

Estimating the Cost of Supply

Alternatives to the Long Run Marginal Cost

- Use Short Run Marginal Costs;
- Use Average Incremental Costs;
- Use "Standard" Costs.

On the Demand side, the Netback Value is used as a proxy for the Marginal Benefit measure.

Estimating Short Run Marginal Cost: Key Considerations

1. Decreases in the quality and/or reliability of service, possibly remedied by resort to backup generation;

2. Lack of adequate reserve margin; and

3. Value of unserved energy.

The SRMC has two parts, and energy component and a capacity component. The energy component is easily measured, provided the input energy prices reflect the value to users. The capacity cost is represented as:

$$MCC = (OC-£) * (LOLP), \qquad (1)$$

Where:

- ✓ MCC is marginal capacity cost;
- ✓ OC is the cost of unserved energy;
- ✓ £ is the operating cost for the marginal capacity addition; and
- ✓ LOLP is the loss of load probability.

If the MCC is greater than the right-hand-side of (1), then the system is under capacity and payment of a capacity credit is justified up to the value of that term.

Average Incremental Cost

This formula for estimating future costs is often used by the World Bank. It can be represented as:

$$AIC_0 = \frac{SUM^T_{j=1}\ [I_j + (R_j - R_o)]/(1 + i)^j}{SUM^T_{j=1}\ [Q_j - Q_o]/(1 + i)^j} \qquad (2)$$

where

I_j = capital cost in year j

R_j = operating and maintenance cost in year j

R_0 = operating and maintenance costs in year 0

O_j = output of energy source in year j

O_0 = output of energy source in year 0

i	=	discount rate
T	=	time horizon of the analysis. Year 0 is the initial point

The AIC can be used to estimate the cost of supply for "Standard" technologies.

Netback Values

The netback value represents the maximum value that an energy resource can attain. As such, it represents a price ceiling. That is,

$NB_x \geq AIC_x + DV_x$, i.e., $NB_x \geq$ economic supply $cost_x$

The formula for estimating the netback value is:

$$NB_{coal} = \frac{P_e - I_{coal}/unit}{Cons_{coal}/unit,} \qquad (5)$$

where P_e is the Price of the electricity purchased from the generator.

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The netback Value can also be estimated using the production or generation cost of a competing fuel, this is called the opportunity cost approach.

i.e.,

$$NB_{oil} = \frac{[I_{oil}/\text{unit} - I_{oil}/\text{unit} + F_{oil}/\text{unit}]}{Cons_{coal}/\text{unit}} \quad (4)$$

for a case where an oil-fired electric generating station is replaced by a coal-fired one.

where

I_{coal} = investment and operating costs required to use coal.

I_{oil} = investment and operating costs required to use oil.

F_{oil} = cost of fuel oil

$Cons_{oil}$ = oil consumption per KWh in tonnes or 10^6 BTU

The netback value calculation points out several key considerations, including:

- The importance of the sales price to the ability to purchase fuel;
- The importance of generation efficiency to the ability to pay for fuel;
- The relationship between the price of a fuel and competitive generation options.

NATURAL GAS RATEMAKING SEMINAR

Jadwisin, Poland
May 18-20, 1992

Sponsored By:

U.S. Agency for International Development
Emergency Energy Program In Eastern and Central Europe

Conducted by:

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POLAND NATURAL GAS RATEMAKING SEMINAR

Agenda

Monday May 18
1:30 - 5:30 PM

I. Overall Economics as Applied to Gas Ratemaking

- A. Supply/Demand
- B. Price elasticity of demand for different customers
- C. Inter-fuel substitution
- D. Price elasticity of supply
- E. Resource accounting

II. Public Utility Regulation

- A. Natural monopoly/economics of scale/scope
- B. Role of public utility regulation

III. Capital Formation

IV. Ratemaking for Regulated Gas Utilities

- A. Ratemaking objectives (TABLE)
  1. Economic Efficiency
  2. Equity
  3. Administrative costs
  4. Revenue recovery
  5. Stability
  6. Conservation

Tuesday May 19
9:00 AM - 12:00 PM

- B. Embedded cost-of-service
  1. Terminology (Rate base, depreciation, capital structure, etc.)
  2. Embedded cost-of-service analysis
     - a. BSA calculator (spreadsheet)
     - b. Goal: regulated utility has opportunity to recover reasonable embedded costs plus return

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Tuesday May 19
9:00 AM - 12:00 PM
(Continued)

3. Calculate system average embedded cost of service (costs/volume)
4. Identify required level of system-average rate

C. Rate Design

1. Cost classification: classify of various cost-of-service components by nature of cost causation:

   a. Demand costs vary with system capacity, e.g., mainline pipeline costs
   b. Commodity/energy costs vary with usage/ throughout, e.g., gas costs
   c. Customer costs vary with number of customers, e.g., service lines and metering costs

2. Cost allocation: allocate classified costs to customer classes:

   a. Demand allocators:
      i) Class coincident demand
      ii) Class non-coincident demand

   b. Commodity/energy allocator - class throughout
   c. Customer allocator - number of customers per class

3. Identify rate forms

   a. Demand charge (recover demand costs)
      i) D-1 - daily capacity
      ii) D-2 - annual/seasonal capacity

   b. Commodity/energy charge (recover commodity/
      energy costs)

      i) flat rate
      ii) step rate
         aa) rising block
         bb) declining block

Tuesday May 19
1:30 - 5:30

c. Customer charge (recover customer costs)

4. Rate design methodologies

   a. Commodity charge pricing
   b. Demand charge pricing
   c. Combinations

      i) MFV (and predecessors)
      ii) SFV

5. Seasonal & Geographical rates - enhance economic efficiency by varying rates according to cost causation related to:

   a. Time of use (season)
   b. Geography/distance

6. Marginal costs - enhance economic efficiency, but need to adjust to yield embedded cost recovery
7. Value of service:

   a. Alternate fuel pricing
   b. Value of reliability
   c. Rate instability unrelated to underlying cost of service (either-embedded or marginal)
   d. Need to adjust to yield embedded cost recovery

Wednesday May 20
9:00 AM - 12:00 PM

D. Ratemaking dilemma - "judgement" ultimately requires to reconcile conflicting objectives

<u>Example</u>:

Economic efficiency - marginal cost pricing
Revenue recovery - embedded cost pricing
Equity - cost subsidies imply prices that differ from <u>both</u> marginal and embedded costs.

NATURAL GAS RATEMAKING SEMINAR
Jadwisin, Poland

SPEAKERS

Mr. John P. Banks is a Senior Associate with the Washington, D.C.-based consulting firm of International Resources Group. He specializes in the economic and political analysis of global oil and gas markets. His expertise covers energy pricing regimes and policies, supply and demand analysis, as well as consumption and production patterns. Mr. Banks has extensive experience working with senior energy officials in Eastern and Central Europe, especially in identifying technical assistance needs and implementing aid programs and projects. Mr. Banks has organized and managed technical assistance efforts in Bulgaria, the Czech and Slovak Federal Republic, Hungary, Poland, and Romania. He currently serves as Project Manager for two components of USAID's Emergency Energy Program in Eastern and Central Europe. Mr. Banks received his M.S. in international economics and finance from Georgetown University.

Dr. Benjamin Schlesinger is President of Benjamin Schlesinger and Associates (BSA), a Washington-based consulting firm specializing in all phases of the natural gas industry. He is one of the most respected experts in the U.S. on natural gas markets, with detailed knowledge of engineering and technical issues related to exploration, development, transmission and distribution. Dr. Schlesinger's expertise includes regulatory, financial and economic analysis as well as corporate strategic planning, legal, accounting and management/organizational issues. He assists clients in developing and restructuring natural gas purchasing strategies and analyzing new gas marketing mechanisms and programs. Dr. Schlesinger has conducted numerous international natural gas studies including extensive work in Europe: Austria, Belgium, Holland, Germany, and the United Kingdom. Recently, he has assisted IRG in conducting natural gas training seminars in Poland and Bulgaria. Dr. Schlesinger received his PhD in Industrial Engineering from Stanford University.

Mr. John Slocum is a Project Manager with BSA, where he is responsible for market and regulatory analysis for a wide range of natural gas industry clients, as well as the market research and analysis implications of changing industry structure on market transactions. He analyzes and provides recommendations on managing and dealing with price volatility in natural gas markets. Prior to joining BSA, Mr. Slocum served with the California Public Utilities Commission for three years as a regulatory analyst. He received his M.A. is Public Policy from Harvard.

NATURAL GAS RATEMAKING SEMINAR

Jadwisin, Poland
May 18-20, 1991

SUMMARY REPORT OF PROCEEDINGS

SUMMARY REPORT OF PROCEEDINGS

Natural Gas Ratemaking Seminar
Jadwisin, Poland

During the period May 18-20, 1992, IRG conducted a *Natural Gas Ratemaking Seminar* in Jadwisin, Poland. The IRG Team comprised Mr. John P. Banks, seminar coordinator and manager, and Dr. Benjamin Schlesinger and Mr. John Slocum. IRG's effort was aimed at assisting the Polish National Oil & Gas Company (PGNIG) and its major gas distribution functions to comprehend and evaluate better competitive energy markets. In particular, IRG sought to impart an understanding of relevant analytic tools and the rate-making implications of their changing natural gas economic and pricing situation.

The following materials were prepared in conjunction with this Seminar:

- An example of a gas pipeline cost-of-service model
- Selected gas rate calculations and examples of different kinds of tariffs
- Model contracts for natural gas supply/purchase, and transportation
- Relevant reprints from AGA's Gas Rate Fundamentals and other important sources of information
- A glossary of rate design and gas price policy terminology.

During the Seminar, the IRG Team made use of additional graphics in-hand on gas pricing and market competition, and made liberal use of the flip-charts for illustrating Poland's gas markets, pipeline transporters, supply options, several U.S. gas pipeline diagrams, retail rate examples, and economic principles.

There was great interest in and enthusiasm for the seminar and the technical materials presented. Attendance was quite high (approximately 60 people), and PGNIG central planners and economists were present as well as many individuals from PGNIG's

dispersed regional distribution enterprises, whose viewpoint was especially interesting in that they appeared to suspect and/or desire that they may be spun off in the near future.

Seminar Sessions

First afternoon (5/18/92)

The IRG Team began by presenting an overview of the goals, contents and direction of the seminar, broadly covering segments of the gas industry (production, transportation, distribution), gas supply and demand analysis, pricing theory and models, industry strategy, rate setting, design and the regulatory oversight/approval process.

First morning, Part I (5/19/92)

The IRG Team walked participants through the regulated ratemaking process in the U.S., using a recent Tennessee Gas Pipeline expansion spreadsheet to illustrate financial structure, rate base, capital recovery, tax gross-up, test year, fixed-variable rate design.

First morning, Part II (5/19/92)

Using a model gas transportation agreement distributed in advance, basic sanctity and guarantee concepts, maximum and nominated flow arrangements, penalties, binding terms and force majeure, and other key provisions were reviewed.

First afternoon, Part I (5/19/92)

Using the model gas purchase agreement, IRG presented major elements of long-term gas sales focusing on long-term pricing and warranty provisions, as well as spot-term purchases, gas reserve accounting and commitments, and the major regulatory interface issues.

Second afternoon, Part II (5/19/92)

Drawing on experiences gleaned by questioning the group, basic rate-making principles and applications at the distribution level to key customer classifications were reviewed: residential, commercial (small/large), industrial (boilers/feedstock/process uses), electricity generation and cogeneration, and others.

Second afternoon, Part III (5/19/92)

Continuing the above, the IRG Team presented and discussed U.S. examples of seasonal rates, distance and zones, firm and interruptible gas transportation and sales.

Second morning, Part I (5/20/92)

The foregoing pieces were pulled together into a review of gas pricing models in current use, including structure, basic economics, and the energy price forecasting process. In addition, the objectives of regulated ratemaking, focusing on the key tradeoff between equity and economic efficiency were reviewed.

Second morning, Part II (5/20/92)

The seminar was concluded with an illustration of market pricing of natural gas, introducing seasonal gas prices, basing point configuration, and the key differences underlying gas industries in Europe (including Eastern Europe) and North America.

Significant Points from the Seminar

- As in Bulgaria, Poland's gas pricing is quite driven by its highly limited supply option: ie., Russian gas. Unfortunately, therefore, the opportunities are likewise limited for Poland to profit from using U.S. style economic models to analyze alternative gas pricing policies.

- Poland appears to be moving quickly toward competitive market mechanisms, although PGNIG's transition is not as quick. Generally in Europe, gas companies are state-run monopolies that buy gas in a rather uncompetitive market, thus PGNIG's economic role under the old regime is not necessarily out of step with the rest of Europe today. In fact, PGNIG certainly has parallels throughout the West: monopolies in France, California, Italy, and Holland bear reasonable similarities to PGNIG to varying degrees.

- An issues of concern among participants in the Seminar largely gravitated around keeping PGNIG intact, versus the prospect for spinning-off the local distribution companies and giving each its municipal franchise.

- Of particular interest was the identification of long-term contracting with specific warranty/performance provisions and the strategic use of demand charge pricing as a tool to maintain system reliability and attract needed capital for system expansion.

NATURAL GAS RATEMAKING SEMINAR

Jadwisin, Poland
May 18-20, 1991

LIST OF PARTICIPANTS

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LIST OF PARTICIPANTS

NATURAL GAS RATEMAKING SEMINAR

Jadwisin, Poland
May 18-20, 1992

1.	Lidia Nagrodkiewick	Ministry of Industry and Trade
2.	Tadeusz Capala	Ministry of Industry and Trade
3.	Stefan Lober	Ministry of Finance
4.	Teresa Kubacka	Ministry of Finance
5.	Barbara Szewczyk	Polish Oil and Gas Company (PGNIG)
6.	Marta Kinderer	PGNIG
7.	Elizbieta Broczewik	PGNIG
8.	Aleksander Magiera	PGNIG
9.	Zbigniew Rozanski	PGNIG
10.	Zofia Modrowska	Wielkopolska Regional Gas Utility
11.	Roman Colka	Wielkopolska Regional Gas Utility
12.	Marian Klos	Wielkopolska Regional Gas Utility
13.	Jan Popenda	Upper Silesia Regional Gas Utility (Zabrze)
14.	Jerzy Wilski	Upper Silesia Regional Gas Utility (Zabrze)
15.	Marian Szafarski	Upper Silesia Regional Gas Utility (Zabrze)
16.	Henryka Sobon	Upper Silesia Regional Gas Utility (Zabrze)
17.	Andrzej Pilaszek	Warsaw Regional Gas Utility
18.	Teresa Lobradowska	Warsaw Regional Gas Utility
19.	Alicja Grzegorozyk	Warsaw Regional Gas Utility
20.	Reresa Adamczyk	Karpaty Regional Gas Utility (Tarnow)
21.	Janusz Nowicki	Karpaty Regional Gas Utility (Tarnow)
22.	Jan Liszka	Karpaty Regional Gas Utility (Tarnow)
23.	Wieslaw Chzoszcz	Karpaty Regional Gas Utility (Tarnow)
24.	Zofia Orlowska	Karpaty Regional Gas Utility (Tarnow)
25.	Andrzej Zgedb	Karpaty Regional Gas Utility (Tarnow)
26.	Kazimierz Makowicz	Pomorski Regional Gas Utility (Gdansk)

LIST OF PARTICIPANTS
(continued)

The following individuals are from Local Gas Utilities in these cities:

27.	Danuta Kowolewska	Koszalin
28.	Ryszard Zarna	Koszalin
29.	Andrzej Wrobel	Tarnow
30.	Waldemar Potrowski	Pulawy
31.	Maria Trefon	Opole
32.	Anna Biernacka	Opole
33.	Marian Szkolut	Lublin
34.	Jerzy Piotrowin	Lublin
35.	Janina Zawada	Bialystok
36.	Teresa Ludankiewicz	Bydgoszcz
37.	Irena Kowolczyk	Bydgoszcz
38.	Joanna Kmiecik	Gdansk
39.	Teresa Jaworska	Lodz
40.	Irena Brozynska	Lodz
41.	Walentyna Zastarna	Szczecin
42.	Julian Wiater	Rzeszow
43.	Krystyna Sarna	Krakow
44.	Aleksander Chwodrzba	Krakow
45.	Lenon Lianski	Warsaw
46.	Miroslaw Calach	Warsaw
47.	Antoni Tecza	Walbrzych
48.	Anna Saricka	Sandomierz

LIST OF PARTICIPANTS
(continued)

49.	Janina Mialkowska	Kielce
50.	Maria Klepuszerska	Slupsk
51.	Kazimierz Lagocka	Jaroslaw
52.	Ursula Jawanska	Elblag
53.	Cecylia Wasowcz	Olszlyn
54.	Krystyna Ruswel	Rzeszow
55.	Janusz malinski	Zgierz
56.	Ryszard Walysiak	Kalisz

Major End-Users

57.	Teresa Dylus	Steel Plant "Batory" (Tarnow)
58.	Danuta Dzierzbicka	Chemical Industry Association
59.	Roman Nasternak	Siarkopol (sulfur producer)
60.	Zbigniew Brozonowis	Azoty Chorzow (chemical plant)

NATURAL GAS RATEMAKING SEMINAR

Jadwisin, Poland
May 18-20, 1991

PRESENTATION MATERIALS

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RATEMAKING ECONOMICS

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POLAND GAS RATEMAKING SEMINAR

Presented by:

Benjamin Schlesinger, President
John Slocum, Project Manager

Benjamin Schlesinger and Associates, Inc.
7201 Wisconsin Avenue, Suite 740
Bethesda, MD 20814
(301) 951-7266

May 1992

The purpose of this seminar is both to inform the Polish gas industry officials of typical ratemaking practices and issues in the United States and to engage in a discussion of Polish gas ratemaking practices and issues. Our overall objective is to assist the Polish officials in developing insights on relevant modeling techniques, the application of economic principles to gas ratemaking, and the policy implications encompassing the ultimate reconciliation of economic efficiency and equity in the determination of appropriate gas prices for the Polish economy.

In this session, we will review and discuss numerous issues related to ratemaking for regulated natural gas utilities in the United States. The format will be to present real life examples of the ratemaking process and outcome, including a definition of ratemaking terminology, a demonstration of a cost-of-service model for a U.S. pipeline capacity expansion project, and a detailed examination of actual, currently-effective rate structures for several North American pipelines.

In particular, in this seminar we will attempt to cover the following material:

- Overall economics as applied to gas ratemaking, including a review of gas supply and demand, price elasticity of demand for different customer classes, inter-fuel substitution, supply price elasticity, and resource accounting.

- An overview of public utility regulation, including the concept of a natural monopoly and the role of public utility regulation.

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- A discussion of capital formation for gas utilities.
- A review of ratemaking for regulated gas utilities in the U.S., including the identification of ratemaking objectives, the development of an embedded cost-of-service analysis, an overview discussion of rate design issues, and a discussion of the inherent tradeoffs involved in establishing "just and reasonable" rates.

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¶2510 Base Rates and Surcharges

The following are Midwestern's effective transportation rates, sample rate calculation, components of effective rates and discount rates.

¶2510.1 Effective Rates.

The following transportation are effective February 1, 1991. The rates apply to gas delivered by Midwestern to or for the account of the shipper:

NOVEMBER - MARCH:

RATE SCHEDULE FT - Firm Transportation Service

Rate Schedule And Rate	Base Tariff Rate Per Dth	ACA Surcharge	Rate Per Dth After Current Adjustment(1)(2)
FT-1			
Demand:	$1.27	—	$1.27
Commodity (Max)	$0.0196	$0.0021	$0.0217
Commodity (Min)	$0.0100	$0.0021	$0.0121

RATE SCHEDULE IT - Interruptible Transportation Service

Rate Schedule And Rate	Base Tariff Rate Per Dth	ACA Surcharge	Rate Per Dth After Current Adjustment(1)(2)
IT-1 (Max)	$0.0614	$0.0021	$0.0635
IT-1 (Min)	$0.0100	$0.0021	$0.0121

APRIL - OCTOBER:

RATE SCHEDULE FT - Firm Transportation Service

Rate Schedule And Rate	Base Tariff Rate Per Dth	ACA Surcharge	Rate Per Dth After Current Adjustment(1)(2)
FT-1			
Demand:	$1.15	—	$1.15
Commodity (Max)	$0.0146	$0.0021	$0.0167
Commodity (Min)	$0.0100	$0.0021	$0.0121

RATE SCHEDULE IT - Interruptible Transportation Service

Rate Schedule And Rate	Base Tariff Rate Per Dth	Rate Per Dth ACA Surcharge	After Current Adjustment(1)(2)
IT-1 (Max)	$0.0524	$0.0021	$0.0545
IT-1 (Min)	$0.0100	$0.0021	$0.0121

(1) The GRI Surcharge of $0.142 per Dth is not applicable to interruptible transportation service for other interstate pipelines who are members of the Gas Research Institute, but shall be added to other charges under Rate Schedules IT-1 and FT-1.

¶1510 Transportation Rates and Surcharges

The following are El Paso's effective maximum transportation rates, sample rate calculation and discount rates.

¶1510.1 Effective Rates

The following maximum transportation rates are effective Jan. 1, 1991:

INTERRUPTIBLE TRANSPORTATION
($/dth)

Rate Schedule	Rate
T-1	
Mainline Transmission Charges	
1. From San Juan Basin to:	
A. Production Area - San Juan	.1474
B. Texas	.1604
C. New Mexico	.1677
D. Arizona	.2276
E. Nevada	.2729
F. California	.3350
2. From Permian Basin to:	
A. Production Area	.1474
B. Texas	.1624
C. New Mexico	.1793
D. Arizona	.2394
E. Nevada	.2928
F. California	.3535
3. From Anadarko Basin to:	
A. Production Area	.1474
B. Texas	.1632
C. New Mexico	.1901
D. Arizona	.2560
E. Nevada	.3056
F. California	.3662
Mainline Shorthaul and Backhaul	.1474
Field Transportation Charges	.0982
Production Area Charges	
A. Dehydration	.0083
B. Purification	.0795
C. Products Extraction	.1494
San Juan Triangle	
Facilities Commodity Charge	.0405

These rates do not include the GRI surcharge of .0147/dth, the ACA surcharge of .0023/dth and the take-or-pay cost recovery throughput charge of .0388/dth.

¶4310 Transportation Rates and Surcharges

The following are Southern's effective transportation rates, sample rate calculation and discount rates.

¶4310.1 Effective Rates

The following transportation rates are effective Feb. 3, 1991:

MARKET AREA
FIRM TRANSPORTATION RATES
SUMMER (March - Nov.)
WINTER (Dec. - Feb.)

	Zone 1	Zone 2	Zone 3
Reservation Charge (All rates in $/mmBtu unless otherwise indicated)			
Maximum: Demand-1			
Summer	$4.21	$6.32	$7.30
Winter	$10.86	$13.04	$13.26
Minimum: Demand-1			
Summer	$0.00	$0.00	$0.00
Winter	$0.00	$0.00	$0.00
Commodity Rate (1)			
Maximum:			
Summer	.1120	.1190	.1660
Winter	.1340	.1350	.1820
Minimum:			
Summer	.0010	.0010	.0010
Winter	.0030	.0030	.0030
Forward Haul Fuel			
Used and Unaccounted For	1.5%	2.3%	2.6%
Intrazone Fuel			
Used and Unaccounted For	1.5%	1.5%	1.5%
Backhaul Fuel	0.6%	0.6%	0.6%

(1) These rates exclude a GRI surcharge of .0142/mmBtu, an ACA surcharge of .0023/mmBtu, and a Take-or-Pay surcharge of .08187/mmBtu.

TENNESSEE GAS PIPELINE COMPANY
DOCKET NO. CP89-629-001

INCREMENTAL COST OF SERVICE ANALYSIS

DAILY VOLUME	427	DEP.	0.025	DEBT	0.4206	EQUITY	0.5794	SIT	0.0368	W. CAP	0.00
LOAD FACTOR	0.85	O&M	0.05	C DEBT	0.0970	C EQ	0.16	FIT	0.3400	OT	0.00
GNP PRICE INDEX	0					RETURN	0.1335	TOT IT	0.3643		

YEAR		1991	1992	1993	1994	1995
GROSS PLANT		111,283	111,283	111,283	111,283	111,283
NON DEPRECIABLE						
AFUDC		6,297	6,297	6,297	6,297	6,297
DEFERRED INC. TAX		82	1,024	0	0	0
DEPRECIABLE PLANT		104,904	103,962	104,986	104,986	104,986
ACCUM. DEP		2,623	5,222	7,846	10,471	13,096
NET PLANT (EOY)		108,661	98,740	97,140	94,515	91,891
AVG. WORK CAP+MAT		0	0	0	0	0
RATE BASE		108,661	98,740	97,140	94,515	91,891
RETURN		14,506	13,182	12,968	12,618	12,267
OPERATING REVENUE		15,915	15,522	15,520	15,453	15,387
OPER. & MAINT		716	752	790	829	871
DEPRECIATION		2,623	2,599	2,625	2,625	2,625
OTHER TAXES		3,864	3,864	3,864	3,864	3,864
OP INC BEF INT		8,712	8,307	8,242	8,135	8,028
INTEREST EXPENSE		4,434	4,029	3,964	3,856	3,749
EQ AFUDC CAP		4,279	4,279	4,279	4,279	4,279
STATE TAX BASE		22,574	21,127	20,894	20,511	20,128
STATE INC. TAX		830	776	768	754	740
FEDERAL TAX BASE		21,744	20,351	20,126	19,757	19,389
FEDERAL INC. TAX		7,393	6,919	6,843	6,717	6,592
TOTAL INC. TAX		8,223	7,696	7,611	7,471	7,332
RETURN ON EQUITY		10,073	9,153	9,005	8,761	8,518
TOTAL FIXED COSTS		29,215	27,340	27,067	26,578	26,088
TOTAL VAR. COSTS		716	752	790	829	871
TOTAL COSTS		29,931	28,092	27,857	27,407	26,958
THROUGHPUT		132,506	132,506	132,506	132,506	132,506
UNIT COST ($/MMBtu)		$0.2259	$0.2120	$0.2102	$0.2068	$0.2034
MFV RATE:						
Commodity ($/MMBtu)		0.1408	0.1300	0.1284	0.1256	0.1229
Demand ($/MMBtu/M)		2.2006	2.1205	2.1164	2.0994	2.0825
Demand ($/MMBtu)	85%	0.0851	0.0820	0.0819	0.0812	0.0805
Total Cost ($/MMBtu)		$0.2259	$0.2120	$0.2102	$0.2068	$0.2034
SFV RATE:						
Commodity ($/MMBtu)		0.0027	0.0028	0.0030	0.0031	0.0033
Demand ($/MMBtu/M)		5.7702	5.4079	5.3583	5.2666	5.1751
Demand ($/MMBtu)	85%	0.2232	0.2092	0.2073	0.2037	0.2002
Total Cost ($/MMBtu)		$0.2259	$0.2120	$0.2102	$0.2068	$0.2034

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MODEL GAS SALES AND PURCHASE AGREEMENT

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GAS SALES AND PURCHASE AGREEMENT

between

[NAME OF SELLER]

and

[NAME OF BUYER]

Dated as of:

[DATE]

(ABRIDGED FOR TRANSLATION -- NOT FOR LEGAL PURPOSES)

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NOTE: Portions of the following material have been adapted, or taken verbatim in cases, from existing gas transportation and supply contracts offered by major U.S. pipeline and producing companies.

GAS SALES AND PURCHASE AGREEMENT

This Gas Sales and Purchase Agreement is entered into as of [DATE] between [NAME OF BUYER] ("Buyer") located at [ADDRESS] and [NAME OF SELLER] ("Seller"), a corporation organized and validly existing under the laws of [STATE], having an office for the transaction of business at [ADDRESS].

INTRODUCTION

WHEREAS, Seller has Gas supplies available to it in various locations reasonably accessible to the transportation facilities of [NAME OF PIPELINES] ("Transporting Pipelines"), which are and will be available for sale from time to time;

WHEREAS, Buyer has firm transportation rights and is seeking to purchase Gas supplies on a Firm Basis; and

WHEREAS, Seller and Buyer desire to enter into a Gas Purchase Agreement relating to the sale and purchase of such available Gas supplies;

NOW, THEREFORE, in consideration of the mutual promises and agreements in this Gas Purchase Agreement, Seller and Buyer today agree to bind themselves as follows:

ARTICLE I - DEFINITIONS

1.1 The term "Commodity Charge" shall mean the fee which Buyer shall pay Seller for each cubic meter of Gas that Seller delivers to the Delivery Point for Buyer's account.

1.2 The term "Cubic Meter" or "m^3" shall mean that volume of Gas which occupies one cubic meter when such Gas is at a temperature of fifteen degrees Celsius (15°C) and at a pressure of one hundred-and-one and three hundred-and-twenty-five thousandths (101.325) kiloPascals ("kPa") absolute.

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1.3 The term "Day" shall mean a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

1.4 The term "Firm Basis" shall mean that Gas will be available for delivery and sale by Seller to Buyer without interruption unless such sale or delivery interruption is excused by, or authorized by, other provisions of this Gas Purchase Agreement.

1.5 The term "Gas" shall mean the methane, ethane and heavier hydrocarbons remaining in the vapor phase of gas-well Gas, oil-well Gas, or the combination of both delivered at the Delivery Point.

1.6 The term "Gas Purchase Agreement" shall mean this Gas Sales and Purchase Agreement.

1.7 The term "Month" shall mean a calendar month.

1.8 The term "Parties" shall refer to the Seller and the Buyer.

1.9 The term "Reservation Charge" shall mean the monthly fee as described in Article VII of this Gas Purchase Agreement which Buyer has agreed to pay to Seller for the right to call upon a certain volume of Gas on a Firm Basis.

1.10 The term "1,000 Cubic Meters" or "10^3m^3" shall mean one thousand (1,000) cubic meters.

ARTICLE II - QUANTITY

2.1 Buyer and Seller agree that Buyer will have the right to call upon Seller to deliver and sell up to [QUANTITY] 10^3m^3 ("Maximum Daily Quantity") on a Firm Basis and that Buyer shall exercise its rights by making a monthly nomination in accordance with the procedure for nominations provided in Article IV of this Gas Purchase Agreement.

2.2 Subject to the terms and conditions hereof, Seller agrees to sell and deliver or have delivered on a Firm Basis that volume of Gas which may be nominated each Month by Buyer, and Buyer agrees to purchase such nominated volumes, such volume not to exceed the Maximum Daily Quantity.

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2.3 Seller reserves unto itself the sole and exclusive right to manage its Gas supply available to Buyer without interference of Buyer or third parties.

2.4 On a rolling twelve-Month basis, Buyer shall provide Seller with a list of projected volumes that may be nominated by Buyer for each of the next twelve Months. Such list of projected volumes shall be used for supply management purposes by Seller and is non-binding upon the Buyer.

2.5 All quantities of Gas sold pursuant to this Gas Purchase Agreement shall be delivered within the constraints of the Transporting Pipelines' nomination and dispatch requirements. Delivery obligations pursuant to this Gas Purchase Agreement shall be adjusted by and constrained by such pipeline requirements. Seller and Buyer shall take reasonable steps to properly arrange for the nomination, dispatch, and delivery of Gas, and to arrange for required transportation in order to carry out the intent of and obligations of this Gas Purchase Agreement.

ARTICLE III - DELIVERY POINT

3.1 Seller shall arrange and be responsible for the delivery of the volumes purchased herein to the Delivery Point [TO BE SPECIFIED IN A SEPARATE EXHIBIT] at which all of Seller's Gas is to be delivered to Buyer.

3.2 Over time, one of the Parties may desire to change the Delivery Point on Transporting Pipelines' system. Upon receipt of written notice of such proposed Delivery Point changes, the Parties will use all reasonable efforts to obtain authorization from the Transporting Pipelines for the use of such points for deliveries, subject to applicable transportation contracts and tariffs. Once authority for Delivery Point changes has been obtained from the Transporting Pipelines, the Parties agree that such new or changed Delivery Point shall constitute an amendment to the Gas Supply Agreement and shall thereafter be used for the delivery of Gas hereunder, subject to the terms of this Gas Purchase Agreement and the terms and conditions of the applicable transportation contracts and tariffs.

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3.3 Title to all Gas delivered hereunder shall pass to Buyer at the Delivery Point.

ARTICLE IV - NOMINATIONS

4.1 For each Month, Buyer will nominate the average daily volumes Buyer intends to purchase the following Month. Such nominations must be submitted to Seller in writing by telefax transmission no later than five (5) business Days preceding the date nominations are due to the Transporting Pipeline. Buyer has a right to nominate up to the Maximum Daily Quantity and Seller shall have no obligation to deliver a volume in excess of this amount. Any volumes within this entitlement not nominated by Buyer in accordance with the above time schedule shall be deemed released that Month by Buyer, and Seller may dispose of such volumes at its sole discretion.

4.2 Seller shall confirm such nomination from Buyer in writing by submitting to Buyer the volume of Gas to be delivered at the designated Delivery Point. Buyer and Seller shall communicate these nominations as appropriate to the Transporting Pipeline within scheduling deadlines. Such written confirmation may be made by telefax or other electronic media communication.

4.3 Seller shall make arrangements to tender Buyer's nominated volumes at the agreed upon Delivery Point.

ARTICLE V - TRANSPORTATION

5.1 Buyer and Seller agree and understand that transportation of all volumes sold and delivered hereunder shall be provided by third parties, primarily Transporting Pipelines. Buyer represents and warrants that it has firm transportation rights necessary to satisfy its obligations under this Gas Purchase Agreement. Buyer shall be responsible for transportation of volumes from the Delivery Point to Buyer's markets. Seller shall be responsible for transportation from the production area to the Delivery Point. Buyer and Seller shall maintain appropriate contracts with Transporting Pipelines so that each can receive and deliver volumes pursuant to this Gas

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Purchase Agreement; however, neither Party shall be obligated to accept terms or conditions which would adversely affect its ability to perform under this Gas Purchase Agreement. If either Party determines the such terms or conditions are unreasonable, such Party shall so inform the other. Within thirty (30) Days after nomination, the Parties shall either modify this Gas Purchase Agreement to reflect the revised responsibility for such terms which have been deemed unreasonable, or modify this Gas Purchase Agreement to reflect the appropriate reduction in the Maximum Daily Quantity listed herein which is affected by such changes in terms or conditions.

5.2 Seller shall hold Buyer harmless for all costs and penalties which may be assessed by a Transporting Pipeline against Seller prior to the Delivery Point as a result of over or under delivery of Gas. Buyer shall hold Seller harmless for all costs and penalties which may be assessed by a Transporting Pipeline against Buyer at or after the Delivery Point. If any such costs or penalties become likely, the Party becoming aware that such costs may be assessed shall inform the other Party in writing as soon as Party becomes aware. Each Party shall immediately work with the other Party to minimize or eliminate, if possible, such costs or penalties. The Parties shall work with each other and with the Transporting Pipelines to verify delivery and receipt of nominated volumes on a timely basis.

5.3 Notwithstanding anything to the contrary in this Article, in the event a Transporting Pipeline substantially changes its rates which results in higher transportation charges to Seller, the Parties agree to meet promptly to renegotiate this Article. Within thirty (30) Days after notification of such change in transportation costs, the Parties shall modify this Gas Purchase Agreement to reflect any revisions or additions necessary to accommodate these changes and determine the appropriate cost apportionment. If the Parties are unable to reach agreement within such time period, either Party may refer the matter to arbitration as described in Article XVII. Any modifications to this Gas Purchase Agreement, determination of

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cost apportionment, or other provision determined in arbitration, shall be effective on the first Day of the Month following the arbitrators' decision.

ARTICLE VI - BILLING AND PAYMENT

6.1 On or about the fifteenth (15th) Day of the Month following deliveries hereunder, Seller shall render to Buyer an invoice showing the Gas volume delivered during the previous Month and the Reservation Charge payable for the following Month. Adjustments, when required, shall be made in Seller's succeeding Month's statement to the fullest extent practical.

6.2 Buyer shall pay Seller within fifteen (15) Days of receipt of an invoice in accordance with Seller's statement or invoice by electronic funds transfer to Seller's account as specified in Article XX. If Buyer does not pay Seller within such time, Seller, in addition to other options which may be available, may stop deliveries hereunder. Interest shall accrue on any late payment by Buyer, except for bona fide disputes of invoiced amounts, at the [PREVAILING, AUTHORIZED RATE OF INTEREST].

6.3 Each Party hereto shall have the right at all reasonable times to examine the books and records of the other Party to the extent necessary to verify the accuracy of any statement, charge, computation, invoice or demand made pursuant to this Gas Purchase Agreement. Any payment shall be final as to both Parties unless questioned within two (2) calendar years from the date of such payment.

6.4 If during the term of this Gas Purchase Agreement, Seller determines that the financial viability of Buyer has become impaired or unsatisfactory, advance cash payment prior to delivery of Gas or other satisfactory security acceptable by Seller shall be given by Buyer upon demand by Seller and delivery of Gas may be withheld until such advance payment or other security is received. If such payment or assurance is not received within thirty (30) Days of demand, Seller may terminate this Gas Purchase Agreement at any time thereafter upon notice to

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Buyer. If there are instituted by or against Buyer proceedings in bankruptcy or under any insolvency law, Seller may terminate this Gas Purchase Agreement at any time.

ARTICLE VII - RESERVATION CHARGE

7.1 Buyer shall pay Seller in accordance with Article VI each month a Reservation Charge equal to the product of the Reservation Rate of [RATE] per 10^3m^3 and the Maximum Daily Quantity.

7.2 The Reservation Charge may be renegotiated pursuant to the provisions of Article XVII.

ARTICLE VIII - COMMODITY CHARGE

8.1 For each 10^3m^3 of Gas delivered to Buyer by Seller at the mutually agreed upon Delivery Point, Buyer shall pay Seller a Commodity Charge which will be equal to the price specified in the [REFERENCE PUBLICATION TABLE] published in the first issue of each Month by [REFERENCE PUBLICATION]. In the event the [REFERENCE PUBLICATION TABLE] ceases to be published by [REFERENCE PUBLICATION], the categories change, or the index is not representative of the market price of the Gas delivered, then the Parties shall mutually agree on a substitute index or pricing mechanism upon which to base the Commodity Charge. If Buyer and Seller are unable to agree upon an alternate index or pricing mechanism, either Party may initiate arbitration solely to determine the Commodity Charge in a manner similar to that described in Article XVII. The Commodity Charge resulting from arbitration shall become effective on the first Day of the Month following the arbitrators' decision and shall remain in effect until renegotiated by the Parties pursuant to Article XVII.

8.2 In addition to any of the changes necessitated by Paragraph 8.1, the Commodity Charge may be renegotiated pursuant to the provisions of Article XVII.

ARTICLE IX - WARRANTY

If either Party is unable, in whole or in part, to perform its obligation under this Gas Purchase Agreement for any reason, such Party shall curtail the other Party on a pro-rata basis with its other comparable Firm Basis contract commitments involving transportation on facilities operated by Transporting Pipelines, recognizing that such contractual agreements have a higher priority for performance than interruptible or best-efforts agreements. For purposes thereof, comparable Firm Basis contract commitments shall mean those having an initial term in excess of one (1) year. In the event either Party fails to perform its obligations under this Gas Purchase Agreement for any reason, then the other Party shall use its best efforts, in a commercially reasonable manner, to mitigate the efforts of such failure. Seller hereby warrants that it will make the Maximum Daily Quantity available to Buyer on a Firm Basis, if nominated by Buyer, subject to all of the terms and conditions of this Gas Purchase Agreement. Seller's obligation to make volumes available shall be excused during events of force majeure, and for other reasons described in other pertinent provisions of this Gas Purchase Agreement. In the event that Seller is unable or fails to make volumes available to Buyer in accordance with this Gas Purchase Agreement, Seller shall not charge Buyer for that portion of the Reservation Charge applicable to the Days and the volumes during which Seller did not perform or shall reimburse Buyer if such amount has already been paid. In the event that Seller's deliveries to Buyer consistently or repeatedly fall materially below Buyer's nominations, then Buyer may cancel this Gas Purchase Agreement upon thirty (30) Days written notice.

ARTICLE X - FORCE MAJEURE

10.1 The term force majeure shall mean acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, storms, floods, washouts, arrests, the order of any court or governmental

authority having jurisdiction prohibiting service or performance, while the same is in force and effect, civil disturbances, explosions, breakage, accident to machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, not including shortages of gas supply or curtailment therefore, inability to obtain or unavoidable delay in obtaining material, equipment, easements, franchises, permits, or authorization and any other causes whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension and which by the exercise of due diligence such Party is unable to prevent or overcome.

10.2 The loss of markets to other gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure.

10.3 In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Gas Purchase Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax or telegraph to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

ARTICLE XI - MEASUREMENT AND TESTING

11.1 Volumes delivered to the Delivery Point hereunder shall be measured and tested according to generally accepted industry standards and measurement and testing provisions contained in the general terms and conditions of the Transporting Pipeline's effective tariff.

11.2 The total amount of Gas delivered and purchased herein shall be determined by multiplying the measured volumes in 10^3m^3 by the heat content of such Gas expressed on a dry basis.

ARTICLE XII - QUALITY

It is understood by the Parties that delivery of the volumes hereunder shall be of the pressure and quality existing in the Transporting Pipeline into which, and at time or times when, delivery is made. Either Party may at any time and from time to time, upon written notice to the other, elect to cease deliveries or takes of any or all volumes that do not meet the required quality specifications of any Transporting Pipeline required to deliver such volumes until such time as quality of said delivery or deliveries again meets the Transporting Pipeline's requirement specifications. If this provision is invoked by Seller and such event is not covered by force majeure, then Seller's obligations as expressly stated in Article IX shall apply.

ARTICLE XIII - TITLE

Seller warrants that it has good and lawful authority to sell the volumes delivered, and that such volumes are free from all liens and adverse claims of any kind or character. Seller agrees to indemnify and hold Buyer harmless from all claims, suits, actions, debts, accounts, damages, costs, losses and expenses of every kind and character arising out of any adverse claim to or against title to such Gas.

ARTICLE XIV - ASSIGNMENT

14.1 This Gas Purchase Agreement shall inure to the benefit and be binding upon the successors and assigns of the Parties; provided, that neither Party shall assign this Gas Purchase Agreement and the rights without first having obtained the written approval of the other Party.

14.2 No conveyance or transfer of any interest in this Gas Purchase Agreement by either Party shall be binding upon the other Party, unless and until such other Party has been furnished

with written notice and, in the event of a conveyance or transfer of an interest in real estate, a recorded copy of the instrument of assignment.

ARTICLE XV - LIABILITY

15.1 Each Party shall assume full responsibility and liability for the maintenance and operation of its properties and shall indemnify and hold harmless the other Party from all liability and expense on account of any and all damages, claims or actions, including injury to and death of persons, arising from any act or accident in connection with the installation, maintenance and/or operation of the property and equipment of the indemnifying Party, its agents or employees.

15.2 Seller shall be deemed to be in control and in possession of the volumes and responsible, as between the Parties, for any damage, injury, or penalty caused or associated with such volumes until such volumes shall have been delivered to the Delivery Point, and Seller shall indemnify and hold Buyer harmless for any and all claims, losses, damages and costs, including reasonable fees of attorneys, arising from such actions.

ARTICLE XVI - TERM

This Gas Purchase Agreement will become effective on the date of execution and shall continue in effect for [NUMBER OF YEARS] years following the initial delivery date subject to and conditioned upon pertinent provisions as more specifically set forth herein. This Gas Purchase Agreement may be extended year to year thereafter upon mutual agreement of the Parties.

ARTICLE XVII - RENEGOTIATION AND ARBITRATION

17.1 On or before [DATE] of each second year thereafter, or as otherwise described in this Gas Purchase Agreement, either Party may request renegotiation of the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligations, and/or other cost sharing provisions of the Gas

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Purchase Agreement. The Parties shall meet and attempt to agree on such renegotiated provisions, and any modifications to this Gas Purchase Agreement resulting from such renegotiations shall become effective on [DATE] of the applicable year. If nether Party requests renegotiation of the applicable terms by [DATE] of the applicable year, then the terms and conditions that exist on [DATE] of the applicable year shall continue in full force and effect.

17.2 In the event Buyer and Seller cannot agree on the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligations, and/or other cost sharing provisions, then either Party may submit such matter to arbitration in accordance with this and the following Paragraphs, it being understood that only the issue of determining the Commodity Charge, Reservation Charge, transportation provisions, quantity purchase obligation, and/or other cost sharing provisions shall be subject to arbitration. While these matters are subject to arbitration, the terms and conditions which existed on [DATE] of that year shall continue in full force and effect. The charges and other provisions determined through arbitration will become effective the Day following the arbitrator's decision and will remain in effect until renegotiated as specified herein.

17.3 Either Party may initiate arbitration by written notice to the other Party within sixty (60) Days after the applicable date when renegotiated provisions for Commodity Charge, Reservation Charge, transportation provisions, and/or other cost sharing provisions were to become effective pursuant to Paragraph 17.1.

(a) Arbitration will be deemed to be initiated when timely written notice, properly addressed and stamped, is sent by ordinary mail. The Party initiating arbitration shall nominate one (1) arbitrator at the same time it initiates arbitration. The other Party shall nominate one (1) arbitrator within ten (10) Days of receiving the notice or arbitration, failing which

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the initiating Party shall nominate a second arbitrator. The two arbitrators shall appoint a third, neutral arbitrator. The third, neutral arbitrator shall be competent and experienced in matters involving the natural gas business, and shall be unaffiliated and without prior financial alliances with either Party, or either of the other arbitrators.

(b) If the two arbitrators are unable to agree on a third arbitrator within sixty (60) Days from initiation of arbitration, then a third arbitrator shall be selected by [AN INDEPENDENT PARTY] with due regard given to the selection criteria above and input from the Parties and other arbitrators. Parties shall undertake to request [AN INDEPENDENT PARTY] to complete selection of the third arbitrator no later than ninety (90) Days from initiation of arbitration. Costs charged by [AN INDEPENDENT PARTY] for this service shall be borne equally by Buyer and Seller.

(c) If [AN INDEPENDENT PARTY] fails to select the third arbitrator within ninety (90) Days from initiation of arbitration, then either Party may petition a court of competent jurisdiction to select the third arbitrator. Due regard shall be given to the selection criteria above and input from the Parties and other arbitrators.

17.4 Once the third arbitrator is appointed, the Parties shall seek to cause the arbitrators to promptly hear and determine (after due notice of hearing and giving the Parties a reasonable opportunity to be heard) the matter of reviewing and determining the Commodity Charge, Reservation Charge, transportation provisions, and/or other cost sharing provisions subject to the following:

(a) In determining the Reservation Charge, the arbitrators shall consider the costs associated with the acquisition of and the value of maintaining Gas supply in accordance with this Gas Purchase Agreement and

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other reservation charges or compensation paid by Buyer for similar services. However, in no event shall the Reservation Charge (at a 100 percent load factor) be less than [AGREED-UPON FIXED PERCENTAGE] of the applicable Commodity Charge escalated at [APPLICABLE INFLATION RATE] per year.

(b) The Commodity Charge shall be established in a manner similar to the initial indexed pricing, shall reflect the market prices for comparable Gas supplies, and shall be no less than the prices paid on Transporting Pipelines' system for similar Gas purchases from similar supply sources.

(c) In establishing the provisions for transportation, Buyer shall pay for all of the costs of transportation including any applicable third-party transportation costs.

17.5 The Parties anticipate that the arbitrators will permit liberal discovery between the Parties, and will issue whatever subpoenas are considered necessary, consistent with applicable law, in order to review and determine these charges and provisions in a fair manner.

17.6 The written decision rendered by the arbitrators, or a majority of the arbitrators, shall be final and binding upon the Parties. The expenses of arbitration shall be borne equally by the Parties, except that each Party shall bear the compensation and expenses of its own counsel, witnesses and employees; provided further, that any costs incurred by a Party in seeking judicial enforcement of any written decision rendered by the arbitrators, or a majority of the arbitrators, shall be chargeable to and borne exclusively by the Party against whom such court order is obtained.

ARTICLE XVIII - REGULATIONS AND LAWS

18.1 In selling and delivering the Gas hereunder, Seller is doing so as a private company and not as a public utility. Seller does not dedicate its production or any of its facilities

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to public use. Seller does not sell or deliver Gas to the public. If any regulatory agency, at any time, shall attempt to assert public utility jurisdiction over Seller by reason of this Gas Purchase Agreement, Seller may, at its sole option, cancel and terminate this Gas Purchase Agreement, notwithstanding anything to the contrary in any other provision of this Gas Purchase Agreement.

18.2 The sale and delivery of the Gas by Seller and the purchase and receipt thereof by Buyer are subject to all valid legislation with respect to the subject matter hereof and to all valid present and future orders, rules and regulations of duly constituted authorities having jurisdiction.

18.3 If all or any portion of the Gas sold and delivered hereunder is conditioned upon or affected by regulatory or governmental approvals, terms, conditions or restrictions during the effectiveness of this Gas Purchase Agreement, the Party so affected may notify the other Party as to said regulatory or governmental approval, term, condition or restriction and may reduce its obligation hereunder for either the sale or purchase, as appropriate, of the volume of Gas affected provided that such Party shall curtail the other Party on a pro-rata basis based upon other Firm Basis contract commitments, recognizing that Firm Basis agreements shall have a higher priority for performance than interruptible or best-efforts agreements.

18.4 This Gas Purchase Agreement shall be governed and construed in accordance with the laws of [STATE], excluding any conflicts of law, rule, or other principle which might refer such construction to the laws of another state.

18.5 If any provisions of this Gas Purchase Agreement shall be held invalid or unenforceable to any extent and for any reason by a court of competent jurisdiction, the remainder of this Gas Purchase Agreement shall not be affected thereby and shall be enforceable to the full extent permitted by law.

ARTICLE XIX - TAXES

19.1 Seller agrees to bear and pay, or cause to be paid, all gross production, severance, and other taxes now and hereafter required by law to be paid to governmental authorities with respect to the production of Gas prior to the Delivery Point. Buyer shall pay, or cause to be paid, all taxes which may be imposed on or with respect to the Gas at or after its delivery at the Delivery Point.

19.2 Buyer agrees that the sales price provided for hereunder excludes any state or local sales or use taxes required to be paid in connection with the sale of Gas pursuant to this Gas Purchase Agreement. Notwithstanding any provision contained under this Gas Supply Agreement to the contrary, all sales or use taxes imposed by law in connection with the sale of Gas under this Gas Purchase Agreement may be collected from Buyer and remitted by Seller to the appropriate taxing jurisdictions, unless Buyer issues Seller a valid sales and use tax exemption certificate for the state in which the sale of Gas took place.

ARTICLE XX - MISCELLANEOUS

20.1 Any notice, request, statement, bill or payment provided in this Gas Purchase Agreement between Buyer and Seller shall be in writing. Such notice may be transmitted via ordinary mail, telefax or acceptable means of electronic transfer; however, telefaxed notices shall be followed up by ordinary mail as soon as possible.

20.2 Any notice shall be considered as duly delivered as of the earlier of the receipt date indicated on the telefax, date of acceptable electronic transmission or the postmark date when mailed by ordinary mail to the other Party at the following address:

(a)	Notice to Seller:	[SELLER'S ADDRESS]
(b)	Payment to Seller:	[SELLER'S ADDRESS AND WIRE TRANSFER ACCOUNT NUMBER]
(c)	Notice to Buyer:	[BUYER'S ADDRESS]

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(d) Statement to Buyer: [BUYER'S ADDRESS]

20.3 Either Buyer or Seller may change its address under this Article by giving written notice to the other Party.

20.4 This written Gas Purchase Agreement contains the entire Gas Purchase Agreement between the Parties, and there are no other understandings or representations between the Parties hereto. This Gas Purchase Agreement may not be amended except by an instrument in writing signed by a duly authorized representative or each Party.

20.5 The failure of either Party at any time to exercise any right or to require performance by the other Party of any provision herein shall in no way affect the right of such Party thereafter to enforce the same, nor shall the waiver by either Party hereto of any breach of any provision herein by the other Party be a waiver of any other breach of such provision, or as a waiver of the provision itself.

20.6 The title headings are for identification and reference only and shall not be used in interpreting any part of this Gas Purchase Agreement.

IN WITNESS WHEREOF, the Parties have duly executed this Gas Purchase Agreement by their proper officers or representatives:

SELLER	BUYER
_____	_____
Name	Name
_____	_____
Title	Title
_____	_____

Attachment A

GAS SUPPLY OBLIGATIONS
(Reserve Requirement Test)

A.1 (a) "Long Term Sales Contracts" means all firm gas sales contracts from time to time, having a term of ten (10) years or more (i) between Aggregator and any purchaser of gas (other than Seller) which provide for the sale of gas from the Supply Pool (as defined in Section 2 of this Contract), or (ii) between Seller and a purchaser of gas (other than Aggregator) which provide for the sale of gas applied by Aggregator to Seller from the Supply Pool; and

(b) "Short Term Sales Contracts" means gas sales contracts which are not Long Term Sales Contracts (i) between Aggregator and any purchaser of gas (other than Seller) which provide for the sale of gas from the Supply Pool or (ii) between Seller and any purchaser of gas (other than Aggregator) and which provide for the sale of gas supplied by Aggregator to Seller from the Supply Pool.

A.2 Buyer acknowledges that Seller and Aggregator deliver gas under the Long Term Sales Contracts and Short Term Sales Contracts from the aggregate supply of gas producible from those gas reserves which are dedicated by gas producers to the performance of Aggregator's gas purchase contracts with such producers (such supply is hereafter referred to as the "Supply Pool"). Buyer further acknowledges that, as such reserves are depleted, the quantities of gas available from the Supply Pool, without further reserve additions, could become insufficient to meet on a sustained basis the daily delivery requirements under all Long-Term Sales Contracts and Short Term Sales Contracts. In anticipation of such event, Seller and Aggregator shall in good faith use all reasonable efforts to add from time to time newly contracted gas reserves to the Supply Pool (it being understood that Seller and Aggregator shall not thereby be obligated to add new

reserves at a price which would result, on a rolled-in basis, in either of them incurring a financial loss in the purchase and sale of gas) in order to assure that, at the end of each contract year hereunder (a "Reference Year"), the relationship between the reserves expected to remain in the Supply Pool at the end of each of the [ ] contract years succeeding the Reference Year (the "Projection Period") and the expected annual level of production from the Supply Pool, as at the end of each of the contract years during the Projection Period, will be such that:

RR/P is not less than [ ]

Where:

"RR" means, with respect to each contract year of the Projection Period, Seller's best estimate (in 10^3m^3) of the reserves remaining in the Supply Pool at the end of such contract year and economically viable and commercially producible for delivery to Buyer during such Projection Period, having regard to confirmed reserve additions during the Projection Period and deliveries under all of the Long-Term Sales Contracts and Short Term Contracts expected to be in effect during the Projection Period; and

"P" means, with respect to each contract year of the Projection Period, Seller's best estimate (in 10^3m^3) of the annual level of production which will be required to maintain full deliveries under Long-Term Sales Contracts during such contract year.

Seller represents and warrants to Buyer that, using Seller's best estimates as at the date of this Contract, the RR/P as determined at the end [ ] years hereunder is greater than [ ].

A.3 Not later than the first day of April immediately following the end of each contract year hereunder, Seller shall, by written notice (the "Supply Notice"), advise Buyer of:

(a) The RR/P for each of the contract years of the Projection Period, calculated using Seller's best estimates as aforesaid and shall include therewith, to the extend compatible with Seller's and Aggregator's reasonable needs to retain information as confidential for marketing purposes, full details of the reserves and production levels used in making such calculation.

(b) Seller shall also deliver to Buyer with each Supply Notice a certificate, prepared by a qualified independent consultant acceptable to Buyer and Seller, which certifies the concurrence of such consultant with Seller's calculation of the RR/P for each year of the Projection Period, and the reserve and production estimates upon which such calculations are based.

A.4 Seller and Aggregator shall not:

(a) during any contract year in which the RR/P for any contract year of the most recently reported Projection Period is less than [ ], enter into any new gas sales contracts or increase or extend its gas sales obligations under existing contracts; and

(b) during any contract year in which the RR/P for any contract year of the most recently reported Projection Period is [ ] or more, enter into new, replacement or extension gas sales contracts such that the RR/P for any such contract year, recalculated to take such new contracts into account, would be less than [ ].

A.5 In the event that, notwithstanding Seller's and Aggregator's reasonable efforts to add newly contracted gas reserves in accordance with Section 2, the total volume of gas available from the Supply Pool on any day is insufficient to enable Seller and Aggregator to deliver the total volume of gas requested for such day by purchasers under all of the Long-Term Sales Contracts and Short Term Sales Contracts:

(a) Seller and Aggregator shall curtail deliveries under Short Term Sales Contracts before curtailing deliveries under Long-Term Sales Contracts in order that full deliveries under Long-Term Sales Contracts may be maintained; and

(b) Seller and Aggregator shall be entitled, after curtailing deliveries under Short Term Sales Contracts, to pro-rate the daily quantity of gas then available from the Supply Pool among all of the Long-Term Sales Contracts. Buyer's share of such quantity under this Contract shall be the lesser of:

(i) the proportion of such quantity which the Daily Contract Quantity under this Contract bears to the total daily contract quantities under all Long-Term Sales Contracts ("Buyer's Pro-rata Share"); or

(ii) Buyer's Scheduled Daily Delivery.

A.6 On each day during the term of the Contract, Seller and Aggregator shall nominate to the suppliers of gas from the Supply Pool for a quantity of gas which is not less than the total quantity of gas requested for delivery on such day by purchasers under Long-Term Sales Contracts.

A.7 Seller and Aggregator shall not be liable to Buyer for damages resulting from failure to deliver the Scheduled Daily Delivery on any day pursuant to this Contract, if and only if:

(a) the Supply Notices issued in each of the three contract years preceding the contract year in which such day occurs (the "Deficiency Year") stated that the RR/P ratio for the Deficiency Year would be [ ].

(b) Seller and Aggregator shall have complied with their obligations under Sections 2, 4, and 5;

(c) Seller and Aggregator shall have complied with their obligations for such day under Section 6;

For greater certainty, except as provided above, this Section 7 is not intended to relieve Seller from liability to Buyer for damages which arise as a result of Seller's failure to comply with any provision of this Contract.

A.8 During any period when Seller and Aggregator is exercising its right hereunder to deliver Buyer's Pro-rata Share of available gas supply in accordance with Section 5(b), the Daily Contract Quantity shall be reduced to that quantity which shall be equal to the Daily Contract Quantity multiplied by a fraction, the numerator of which is the sum of Buyer's Pro-rata Shares during such period as defined in Section 5(b) and the denominator of which is the sum of the Daily Contract Quantities otherwise be in effect during such period; provided, however, that for the purposes of calculating Buyer's Pro-rata Share under Section 5(b), the Daily Contract Quantity which would otherwise be in effect shall be used for such calculation. Buyer shall be at liberty to purchase from another source the difference between the Daily Contract Quantity which would otherwise be in effect and Buyer's Pro-rata Share on each day during the period when Seller is exercising its right to deliver Buyer's Pro-rata Share in accordance with Section 5(b).

A.9 Notwithstanding the provisions of Article II, if, during the term of this Contract, including any extensions agreed to by the parties (the Term"), Buyer receives a Supply Notice which shows that the RR/P for a specific contract year in the Projection Period, as determined in accordance with the provisions of Section 2, is less than [ ] (the earliest such contract year in the Projection Period showing an RR/P below [ ] being hereinafter referred to as the "Forecast Year"), Seller and Aggregator shall have [ ] years from the date of the Supply Notice within which to contract for new reserves in accordance

with Section 2, such that the RR/P for the Forecast Year is increased to at least [ ]; failing which Buyer may, at its option, if the Forecast Year is within the Term, arrange for supplies ("Alternate Supplies") to commence delivery on the first day of the Forecast Year, equal to all or part of the Daily Contract Quantity, as determined in Buyer's sole discretion. Commencing with the first day for which Buyer schedules and takes the delivery of Alternate Supplies, the Daily Contract Quantity for the purposes of this Contract shall be that quantity of gas which is equal to the Daily Contract Quantity then in effect, less the Daily Contract Quantity of the Alternate Supplies, and Seller's overall supply commitment and Buyer's overall purchase commitment shall be reduced to the level of the remaining Daily Contract Quantity.

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MODEL GAS TRANSPORTATION AGREEMENT

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GAS TRANSPORTATION AGREEMENT

between

[NAME OF TRANSPORTER]

and

[NAME OF SHIPPER]

Dated as of:

[DATE]

(ABRIDGED FOR TRANSLATION -- NOT FOR LEGAL PURPOSES)

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NOTE: Portions of the following material have been adapted, or taken verbatim in cases, from existing gas transportation and supply contracts offered by major U.S. pipeline and producing companies.

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GAS TRANSPORTATION AGREEMENT

This Gas Transportation Agreement is entered into as of [DATE] between [NAME OF SHIPPER] ("Shipper") located at [ADDRESS] and [NAME OF TRANSPORTER] ("Transporter"), a corporation organized and validly existing under the laws of [STATE], having an office for the transaction of business at [ADDRESS].

INTRODUCTION

WHEREAS, Transporter owns and operates a high-pressure natural gas pipeline located in close proximity to Shipper's facilities;

WHEREAS, Shipper requires transportation and delivery of [QUANTITY] thousand cubic meters ("10^3m^3") per day of natural gas on Transporter's gas pipeline system on a firm basis, subject to the terms and conditions of this Transportation Agreement;

WHEREAS, Transporter will construct, install and operate facilities, as required, and provide firm transportation for Shipper on its gas pipeline system from the Point of Receipt to the Point of Delivery; and

WHEREAS, Shipper will construct, at its sole cost and expense, and to Transporter's construction standards and practices, a gas service lateral to be used to transport the Shipper's Gas between Shipper's facilities and Transporter's nearby pipeline;

NOW, THEREFORE, in consideration of the mutual promises and agreements in this Transportation Agreement, Shipper and Transporter today agree to bind themselves as follows:

ARTICLE I - DEFINITIONS

1.1 The term "Contract Year" shall refer to the annual period from April 1 of any calendar year to March 31 of the next succeeding calendar year.

1.2 The term "Cubic Meter" shall mean that volume of gas which occupies one cubic meter, when such gas is at a temperature of fifteen degrees Celsius (15°C) and at a pressure of one

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hundred-and-one and three hundred-and-twenty-five thousandths (101.325) kiloPascals ("KPa") absolute.

1.3 The term "Day" shall mean a period of twenty-four (24) hours beginning at 8:00 a.m. on any calendar day and ending at 8:00 a.m. on the following day.

1.4 The term "Maximum Daily Quantity" ("MDQ") shall mean the maximum volume of gas that Shipper can nominate in one day, which is [QUANTITY] 10^3m^3 per day in this Agreement.

1.5 The term "Parties" shall refer to the Transporter and the Shipper.

1.6 The term "Point of Delivery" shall refer to the point at which all of Shipper's Gas transported by Transporter is delivered to Shipper. Such point shall be the outlet of the Transporter's meter located at the Shipper's facility [TO BE SPECIFIED IN A SEPARATE EXHIBIT].

1.7 The term "Point of Receipt" shall refer to the point at which all of Shipper's Gas is tendered by Shipper to Transporter for transportation [TO BE SPECIFIED IN A SEPARATE EXHIBIT].

1.8 The term "Shipper's Gas" shall include all gas belonging to Shipper and transported by Transporter.

1.9 The term "Transporter Standard Tariff Rate" shall refer to the lowest rate per 10^3m^3 (at a 100 percent load factor) for gas transportation service under Transporter's approved Schedule for Gas Service in effect on that day, or, if that tariff rate is eliminated, such other rate that Shipper would have been eligible for if it had not entered into this Transportation Agreement.

ARTICLE II - SCOPE OF TRANSPORTATION SERVICE

Transporter agrees to transport on a firm basis, from the Point of Receipt to the Point of Delivery, for the Shipper's benefit, such quantities of gas as Shipper may from time to time tender to Transporter for transportation.

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ARTICLE III - REPRESENTATIONS AND WARRANTIES

3.1 Shipper makes the following representations and warranties at this time:

(a) Shipper is a corporation duly organized, validly existing and qualified to do business under the laws of [STATE], and is duly authorized to execute this Transportation Agreement and consummate the transactions herein contemplated.

(b) This Transportation Agreement is the legal, valid and binding obligation of Shipper enforceable in accordance with its terms.

3.2 Transporter makes the following representations and warranties at this time:

(a) Transporter is a corporation duly organized, validly existing and qualified to do business under the laws of [STATE], and is duly authorized to execute and deliver this Transportation Agreement and consummate the transactions herein contemplated.

(b) This Transportation Agreement is the legal, valid and binding obligation of Transporter enforceable in accordance with its terms.

ARTICLE IV - TERM OF TRANSPORTATION AGREEMENT

4.1 The term of this Transportation Agreement shall commence on [DATE], and shall continue until [DATE].

4.2 This Transportation Agreement is subject to approval by the [RELEVANT AUTHORITY]. After this Transportation Agreement has been fully executed, Transporter shall promptly file the Transportation Agreement with the [RELEVANT AUTHORITY] for its approval. If the [RELEVANT AUTHORITY] requires a change in this Transportation Agreement, or imposes any other material condition to its approval, or otherwise takes action with respect to this Transportation Agreement that is unacceptable to either Party, the Parties shall, within the next thirty (30) Day period, use their best efforts in good faith to agree upon a mutually satisfactory amendment to this Transportation Agreement, and to

resubmit this Transportation Agreement, as so amended, for any necessary further approval by the [RELEVANT AUTHORITY].

4.3 Firm transportation service shall commence as soon as possible after all necessary facilities have been constructed and placed in operation, and all necessary regulatory authorizations have been received and accepted.

ARTICLE V - TRANSPORTER'S OBLIGATIONS

5.1 The maximum amount of Shipper's Gas that Transporter shall be required to accept at the Point of Receipt for transportation on behalf of Shipper to the Point of Delivery on any Day shall be the MDQ.

5.2 Transportation of Shipper's Gas under this Transportation Agreement shall be on a firm basis, and shall not be subject to interruption or curtailment except as caused by force majeure conditions beyond Transporter's or Shipper's control.

ARTICLE VI - PRESSURE AND QUALITY

6.1 All gas delivered by Shipper to Transporter at the Point of Receipt shall be at such delivery pressures as are required from time to time by Transporter, up to a maximum of [MAXIMUM RECEIPT PRESSURE]. All of Shipper's Gas delivered by Transporter to Shipper at the Point of Delivery shall be at such delivery pressures as are available from time to time to Transporter at such point, up to a maximum of [MAXIMUM DELIVERY PRESSURE] but not lower than [MINIMUM DELIVERY PRESSURE].

6.2 The Parties recognize that the natural gas delivered by Shipper for transportation at the Point of Receipt will necessarily be mixed in Transporter's gas pipeline system with gas received from other sources, and that the specific gas delivered to Transporter cannot be redelivered for Shipper's account. It is further agreed that the natural gas delivered to and by Transporter shall be merchantable natural gas.

6.3 All gas tendered by Shipper for transportation under this Transportation Agreement shall, have a total heating value

of not less than [MINIMUM ENERGY CONTENT] and not more than [MAXIMUM ENERGY CONTENT]. The natural gas received by Transporter and delivered for the account of Shipper:

(a) Shall be free from objectionable odors, dust, gums or gum-forming constituents, or other solid or liquid matter which might interfere with its salability, or injure or interfere with proper operation of the lines, regulators, meters or other appliances through which it flows;

(b) Shall contain no more than 20 parts per million of total sulphur by weight of gas, nor more than 10 parts per million of hydrogen sulfide by weight of gas volume when tested in accordance with the following procedure: A strip of white filter paper previously moistened with fresh 5 percent lead acetate solution shall be exposed to the gas for one and one-half minutes in a previously purged apparatus through which the test gas is flowing at a rate of approximately 0.15 cubic meters per hour; the gas jet shall not directly impinge upon the test strip during the test. At the end of the stated time, the test paper thus exposed shall be compared with a second test strip similarly prepared but not exposed to the test gas. If the exposed strip is not noticeably darker than the comparison strip, the gas under the test shall be considered acceptable. If the exposed strip is noticeably darker than the comparison strip, the gas shall be tested quantitatively for hydrogen sulfide by the Tutweiler or other approved method;

(c) Shall be odorized, except when the transportation and delivery by Transporter of gas that is not odorized is permitted under safety regulations, and Shipper requests and Transporter agrees that gas delivered for the account of Shipper shall not be odorized, and Shipper in writing agrees to perform necessary odorization prior to final consumption;

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(d) Shall not at any time have an uncombined oxygen content in excess of 1 percent by volume, and the Parties shall make every reasonable effort to keep the gas free from oxygen;

(e) Shall not at any time have a carbon dioxide and nitrogen content in excess of 4 percent by volume, and carbon dioxide content shall not at any time exceed 3 percent by volume.

(f) Shall not be delivered at a temperature of more than 49 degrees Celsius (49°C);

(g) Shall not contain more than 65 milligrams of water vapor per cubic meter.

6.4 If the natural gas offered to Transporter for transportation shall fail at any time to conform to the pressure or quality specifications set forth in this Article, then Transporter may refuse to accept delivery. Likewise, if the natural gas offered by Transporter for delivery for the account of Shipper fails at any time to conform to any of the specifications set forth in this Article, then Shipper may refuse to accept delivery pending correction by Transporter. Upon the failure of either Party promptly to remedy any deficiency in quality or pressure, then the other may make changes as may be necessary to bring such gas into conformity with such quality and pressure specifications.

ARTICLE VII - MEASURING AND METERING EQUIPMENT

7.1 The volume and the total heating value of the transportation gas received and delivered shall be determined as follows:

(a) The measurement unit of natural gas transported shall be one (1) cubic meter measured according to Boyle's Law for the measurement of gas under varying pressures with deviations therefrom as provided below, on the measurement basis hereinafter specified.

(b) The unit of volume for purposes of measurement of gas transported for the purposes of determination of

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equivalent volumes shall be one (1) cubic meter of natural gas as defined in Article I.

(c) The total heating value of the gas received at the Point of Receipt and delivered at the Point of Delivery, per cubic meter, shall be determined from a continuous sampling device, by chromatographic analysis, by periodically running a spot sample on a recording calorimeter, or by such other equipment or method as may be mutually agreed upon. The total heating value of the gas shall be determined by Transporter at each such point at least monthly or at other intervals of time as deemed necessary by either Party from a continuous sampling device or other methods mutually agreed upon. The total heating value of the gas so determined at each such point shall be deemed to remain constant until the next determination.

(d) For purposes of computing gas volumes, the temperature of the gas passing through the meters shall be determined for any Day by the continuous use of a recording thermometer so installed that it may properly record the temperature of the gas flowing through the meters.

(e) The specific gravity of the gas passing through each meter utilized shall be determined by the use of a recording gravitometer, from a continuous sample device, or by chromatographic analysis of approved type which shall be checked at least once each month by the use of any other approved method mutually agreed upon. The specific gravity of the gas so determined shall be deemed to remain constant until the next determination.

7.2 Orifice meters installed in measuring stations used in the measurement of the transportation gas to be received or delivered shall be operated in accordance with Specifications of the American Petroleum Institute ("API") Publication Number 2530

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as amended from time to time, including the API Publication for Determination of Supercompressibility Factor of Natural Gas or AGA Committee Report No. 8, titled "Compressibility and Supercompressibility for Natural Gas and Other Hydrocarbon Gases." Turbine meters installed in measuring stations used in the measurement of the transportation gas to be received or redelivered shall be operated in accordance with specifications of the American Gas Association ("AGA") Committee Report #7 which is titled "Measurement of Gas by Turbine Meters." Any modification and amendment thereof as agreed upon by the Parties shall include the use of straightening vanes and pulsation and dampening equipment where necessary.

7.3 Shipper acting jointly with Transporter may install, maintain and operate, at its own expense, such check measuring equipment as desired, provided that such equipment shall be installed so as not to interfere with the operations of Transporter's measuring equipment.

7.4 All installations of measurement equipment applying to or affecting deliveries shall be made in such manner as to permit an accurate determination of the volume and total heating value of natural gas delivered and ready verification of the accuracy of measurement. Care shall be exercised by Shipper in the installation, maintenance and operation of pressure regulating equipment so as to prevent any inaccuracy in the determination of the quantity of gas delivered.

7.5 The characteristics of the measuring equipment will be as follows:

(a) The accuracy of the measuring equipment shall be verified at reasonable intervals and, if so requested, in the presence of representatives of both Parties, but neither Party shall be required to verify the accuracy of such equipment more frequently than once in any 30-Day period. In the event either Party shall notify the other Party that it desires a special test of any measuring equipment, the Parties shall cooperate to secure a prompt verification of the

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accuracy of such equipment. The expense of any such special test, if requested, shall be borne by the Party requesting the test if the measuring equipment tested is found to be in error by not more than two (2) percent.

(b) If upon test, any measuring equipment, including auxiliary instruments, is found to be in error in the aggregate by not more than 2 percent, previous recordings of such equipment shall be considered accurate in computing deliveries of gas, but such equipment shall be adjusted at once to record accurately.

(c) If upon test, any measuring equipment shall be found in the aggregate to be inaccurate by an amount exceeding 2 percent since the last preceding test, such equipment shall be adjusted at once to record accurately, and any previous recordings of such equipment shall be corrected to zero error for any period which is known definitely, but in case the period is not known or agreed upon, such correction shall be for a period extending over one-half of the time elapsed since the date of the last test, but not exceeding a correction period of sixteen (16) Days.

7.6 In the event a meter is out of service or registering inaccurately, the quantities of gas received or redelivered during such period shall be determined as follows:

(a) By using the registration of any check meter or meters, if installed and accurately registering; or in the absence of subsection (a),

(b) By correcting the error if the percentage of error is ascertainable by calibration, tests or mathematical calculation; or in the absence of both subsections (a) and (b), then,

(c) By estimating the quantity received or redelivered by receipts or deliveries during periods under similar conditions when the meter was registering accurately.

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7.7 Each Party shall preserve or cause to be preserved for mutual use all test data, charts, or other similar records in accordance with the applicable rules and regulations of the [RELEVANT AUTHORITY] with respect to the retention of such records.

ARTICLE VIII - RATE

8.1 On and after the date transportation service begins, Shipper shall pay to Transporter each month the following charges:

(a) A Monthly Demand Charge equal to the product of the monthly Demand Rate defined in Paragraph 9.2 of this Article and the Maximum Daily Quantity defined in Article I of this Agreement;

(b) A Commodity Charge equal to the product of the volume actually received by Transporter during the month at the Point of Receipt and the Commodity Rate defined in Paragraph 9.2 of this Article.

8.2 Nomination Schedule and Rates:

Delivery Point(s)	Annual Quantity Nominated (10^3m^3)	Rate (Lev/10^3m^3) Demand Rate	Commodity Rate
[TO BE SUPPLIED]	[TO BE SUPPLIED]	[TO BE SUPPLIED]	

8.3 Transporter shall not be liable for any gas gathering, occupation or production, severance or sales tax, or taxes of similar nature or equivalent in effect which are now or hereafter validly imposed by any lawful authority on the gas transported pursuant to this agreement or on the production thereof. Shipper shall reimburse Transporter the amount of any future tax or other governmental exaction validly laid on and paid by Transporter for, in respect of, or on account of the receipt, transportation or delivery by Transporter of the gas provided for in this

Transportation Agreement; provided, however, that such reimbursement shall not include income, excess profits, capital stock, or general property taxes.

8.4 Transporter shall have the right, from time to time, through filings with the [RELEVANT AUTHORITY] to seek to increase or decrease the rates, and to change the other terms and conditions of this Transportation Agreement, without limitation or reservation; provided, however, that (a) the character of firm service, (b) the term, (c) the quantities, (d) the Points of Receipt and Delivery, and (e) the receipt and delivery pressures shall not be subject to change. Shipper shall have the right to oppose any of the foregoing and to seek a reduction in rates or other changes to the terms and conditions of this Transportation Agreement to the extent that Shipper is legally permitted to do so under applicable provision(s) of law.

ARTICLE IX - OPERATING PROCEDURES AND BALANCING

9.1 Throughout the term of this Transportation Agreement, Shipper shall provide to Transporter by the fifteenth (15th) Day of every calendar month an estimated transportation nomination schedule ("Nomination Schedule") indicating the daily quantity of gas Shipper reasonably anticipates it will require to be transported each Day during the next month, which schedule shall be subject to change on verbal notice as provided for in Paragraph 10.2 of this Agreement.

9.2 Shipper shall have the right to change the Nomination Schedule, but Shipper must notify Transporter verbally of any such changes at least eight (8) hours in advance of the Day on which the change in deliveries will commence, and Shipper shall use its best efforts to do so at least twenty-four (24) hours in advance of any such change. Requested changes to the Nomination Schedule shall be kept to the minimum permitted by operating conditions. Shipper shall deliver or cause to be delivered to Transporter, and Shipper shall receive from Transporter the scheduled daily quantity as nearly as possible at uniform hourly rates.

9.3 It is the intention of the Parties that the total heating value of daily deliveries of Shipper's Gas to Transporter at the Point of Receipt for transportation for Shipper's account shall equal the total heating value of Shipper's Gas that Transporter shall deliver at the Point of Delivery. However, it is recognized that due to operating conditions, the total heating value of gas deliveries into and from Transporter's facilities may not balance on a daily or other short-term basis. The Parties therefore agree to abide by the following balancing procedures:

(a) The quantity of gas delivered or caused to be delivered by Shipper to Transporter at the Point of Receipt for transportation on any Day (less any quantity retained by Transporter for compressor fuel and line loss makeup) shall be redelivered by Transporter for the account of Shipper, balanced on the basis of total heating value.

(b) If the quantity of gas which Shipper schedules to receive from Transporter on any Day is not taken by Shipper during each Day, Shipper shall pay Transporter a scheduling penalty equal to the Commodity Charge applicable under Transporter's Standard Tariff Rate, multiplied by the amount by which the quantity scheduled for delivery to Transporter exceeds the quantity actually delivered, minus 4 percent.

(c) Any monthly imbalance between Shipper's deliveries of gas for transportation and Transporter's redeliveries shall be kept to minimum. At the end of each calendar month, Transporter shall determine the net amount of surplus or deficiency in the total heating value of Transporter's deliveries of Shipper's Gas to the Point of Delivery, above or below the total heating value of Shipper's Gas delivered to Transporter at the Point of Receipt. Transporter shall adjust any net surplus or deficiency of such gas delivered by Transporter by adjusting the quantity of Shipper's Gas dispatched by

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Transporter at the Point of Delivery in the next succeeding calendar month. If Shipper does not within 45 Days immediately following notice by Transporter's dispatcher balance out any monthly imbalance between Shipper's deliveries of gas for transportation and Transporter's redeliveries then:

(i) Shipper shall pay Transporter a penalty equal to two times the Commodity Charge applicable under the Transporter's Standard Tariff Rate, multiplied by any excess quantity received by Shipper; or

(ii) Transporter shall retain at no cost any excess deliveries by Shipper, free and clear of any claims to title.

(d) If an imbalance exists between receipts and deliveries upon termination of this Transportation Agreement or when quantities cease to be delivered to Transporter for transportation, as a result of the depletion of supplies or a termination of deliveries from Shipper's suppliers, such that the quantities delivered by Transporter to Shipper or for the account of Shipper exceed the quantities delivered to Transporter (less the quantities retained for compressor fuel and line loss make-up), Shipper shall immediately take whatever action is required to acquire the quantities necessary to eliminate such imbalance. If such imbalance is not eliminated within a period of sixty (60) Days after written notification to Shipper by Transporter, Shipper shall pay Transporter a penalty equal to two times the Commodity Charge applicable under the Transporter's Standard Tariff Rate, multiplied by such imbalance quantity.

(e) If Transporter determines that, because of operational constraints or other reasons, it cannot reasonably apply any or all the provisions set forth in Sections (a)-(d) above, it may, at its discretion, waive any or

all of such provisions; provided, however, that any such waiver shall be made on a nondiscriminatory basis.

(f) The penalty provisions set forth in Sections (a)-(d) above shall not apply if the excess deliveries or excess takes are caused by Transporter's actions or events of force majeure as such term is defined in Article XIII of this Transportation Agreement.

ARTICLE X - BILLING AND PAYMENT

10.1 Transporter shall render its bill on or before the last Day of each month for the Demand Charges due for service rendered during the preceding calendar month. On or before the 10th Day of each month, Transporter shall render its bill for the Commodity Charge payable for gas services rendered during the preceding calendar month.

10.2 Each Party shall, upon request of the other, mail or deliver for checking and calculation any available documentation that was used in either the measuring of gas and calculation of volumes or billing within twenty (20) Days after the date on which Transporter renders its billing statement for such month for all charges other than demand charges. All records and charts, together with calculations for inspection and verification, are subject to return within ten (10) Days after receipt thereof.

10.3 Shipper, except as otherwise provided in this Agreement, shall pay to Transporter at its designated office: (a) on or before the 10th Day of each month for the Demand Charges due for service rendered by Transporter during the preceding month and billed by Transporter in the statement for such month, and (b) on or before the 20th Day of each month for the remainder of the charges for service which are due.

10.4 If Shipper fails to pay all of the amount of any bill to Transporter when such amount is due, interest on the unpaid portion of such amount shall accrue at [PREVAILING, AUTHORIZED RATE OF INTEREST]. If such failure to pay continues for 30 Days

after payment is due, Transporter, in addition to any other remedy it may have, may suspend further transportation of natural gas until such amount is paid; provided, however, that if Shipper in good faith shall dispute the amount of any such bill or any part thereof, and shall pay to Transporter such amount as it concedes to be correct, and at any time thereafter within 30 Days of a demand made by Transporter, shall furnish good and sufficient surety bond, guaranteeing payment to Transporter of the amount ultimately found to be due under such bill after a final determination, which may be reached either by agreement between the Parties, arbitration or judgment of a court, then Transporter shall not be entitled to suspend further delivery of natural gas unless and until default be made in the conditions of such bond.

10.5 If within 12 months of the date of payment, it shall be found that Shipper has been overcharged or undercharged in any form whatsoever under the provisions hereof, and Shipper shall have actually paid the bills containing such overcharge or undercharge, then within 30 Days after the final determination thereof, Transporter shall refund the amount of any such overcharge with interest at the rate of [PREVAILING, AUTHORIZED RATE OF INTEREST], calculated from the time such overcharge was paid to the date of refund.

ARTICLE XI - ASSUMPTION OF RISK

Shipper shall be deemed to be in control and possession of the gas to be transported until the gas has been delivered to Transporter at the Point of Receipt, and Shipper shall be deemed to be in control and possession of the gas after delivery for Shipper's account at the Point of Delivery. Transporter shall be deemed to be in control and possession of Shipper's Gas after the gas is delivered to Transporter at the Point of Receipt and before the gas is delivered for Shipper's account at the Point of Delivery.

ARTICLE XII - WARRANTIES

Shipper warrants for itself, and for its successors and assigns, that it will at the time of delivery to Transporter for transportation have good and merchantable title to all gas.

ARTICLE XIII - FORCE MAJEURE

13.1 The term force majeure shall mean acts of God, strikes, lockouts, or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, storms, floods, washouts, arrests, the order of any court or governmental authority having jurisdiction prohibiting service or performance, while the same is in force and effect, civil disturbances, explosions, breakage, accident to machinery or lines of pipe, freezing of wells or lines of pipe, temporary failure of gas supply, not including shortages of gas supply or curtailment therefore, inability to obtain or unavoidable delay in obtaining material, equipment, easements, franchises, permits, or authorization and any other causes whether of the kind herein enumerated or otherwise, not reasonably within the control of the Party claiming suspension and which by the exercise of due diligence such Party is unable to prevent or overcome.

13.2 The loss of markets to other gas supplies or fuels, whether or not caused by regulatory determinations or regarding applicable transportation rates, shall not constitute an event of force majeure. The Parties agree that a lack of funds, economic hardship, or other financial cause shall not in any circumstance be an event of force majeure.

13.3 In the event of any Party being rendered unable, wholly or in part by force majeure to carry out its obligations under this Transportation Agreement, other than the obligation to make payment of amounts accrued and due at the time thereof, it is agreed that on such Party's giving notice and full particulars of such force majeure in writing or by telefax or telegraph to the other Party within a reasonable time after the occurrence of the cause relied on, the obligations of all Parties, so far as

they are affected by such force majeure, shall be suspended during the continuance of any inability so caused, but for no longer period, and such cause shall so far as possible be remedied with all reasonable dispatch.

ARTICLE XIV - NOTICES

14.1 Any notice, request, demand, statement or bill provided for herein, or any notice which either Transporter or Shipper may desire to give to the other, shall be in writing and shall be considered as duly delivered when mailed by registered mail addressed to said Party at its last known post office address, or at such other address as any Party may be designate in writing. Routine communications, including monthly statement and payments, shall be considered as duly delivered when mailed by either registered or ordinary mail.

(a) If to Shipper: [ADDRESS]

(b) If to Transporter: [ADDRESS]

ARTICLE XV - EVENTS OF DEFAULT

15.1 Any one or more of the following events shall constitute an Event of Default under this Transportation Agreement:

(a) Failure by either Party to pay any amount due and payable by it pursuant to this Transportation Agreement for fifteen (15) Days after the same shall have become due;

(b) Failure of either Party to perform any material part of this Transportation Agreement, other than in an event of force majeure, and continuance of such failure for a period of thirty (30) Days after written notice to the defaulting Party specifying the nature of such Default and requesting that it be remedied;

(c) Bankruptcy of either Party; or,

(d) If any material representation or warranty made herein shall prove to have been false or incorrect in any material respect at the time made.

ARTICLE XVI - TERMINATION

16.1 Subject to Paragraph 16.2 below, whenever any Event of Default shall have occurred and be continuing, the non-defaulting Party, to the extent permitted by law, may, upon sixty (60) Days prior written notice to the defaulting Party, terminate this Transportation Agreement. In such event, this Transportation Agreement shall terminate unless within such sixty (60) Day period prior to such termination all Events of Default that were the subject of such notice shall have been fully cured, or the defaulting Party has instituted and is diligently pursuing corrective action sufficient to cure such Default.

16.2 No termination of this Transportation Agreement shall relieve the defaulting Party of its liability and obligations.

ARTICLE XVII - ASSIGNMENT OR TRANSFER

Except for assignment in connection with any financing, the Parties agree not to assign or transfer their interest in this Transportation Agreement without the prior written consent of the other Party, which consent shall neither be unreasonably withheld nor delayed. If this Transportation Agreement is assigned without the written consent of the non-assigning Party, the non-assigning Party may terminate this Transportation Agreement on thirty (30) Days written notice to the assigning Party.

ARTICLE XVIII - AMENDMENTS

This Transportation Agreement, or any extension or renewal hereof, may not be amended, changed, modified or altered unless such amendment, change, modification or alteration shall be in writing and signed by the Parties hereto, or by such successor in interest.

IN WITNESS WHEREOF, the Parties have duly executed this Transportation Agreement by their proper officers or representatives:

SHIPPER	TRANSPORTER
_____	Name _____
Name	
_____	Title _____
Title	
_____	Date _____
Date	

SELECTED ARTICLES ON RATEMAKING

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Chapter 6
Load Studies and Analysis

Technical Editor: Charles F. Belknap, Jr. Consumers Power Company

Load studies reveal the characteristics of the various types of gas loads served by a utility. The way a customer consumes gas as well as the quantity used affects the utility's costs. In particular, the demand created by the customer's equipment or appliances (e.g., maximum one-hour or 24-hour consumption of gas and the temporal pattern of usage) affects the cost of providing service. These specific properties, which distinguish the types of gas consumption, constitute load characteristics.

LOAD CHARACTERISTICS

The use of gas by each energy-consuming device and process fluctuates from hour to hour, day to day, and season to season. For a given customer, the combination of these individual consumption patterns determines that customer's load characteristics. In turn, the aggregate load characteristics of a number of customers having some common characteristics of use (e.g., heating, large processing use, etc.) establishes the load characteristics of a class of customers. Aggregating across customer classes establishes the load characteristics of the utility.

It is desirable to portray load characteristics graphically. Such "load curves" show the consumption of gas at hourly intervals during a typical day, during the day of highest use by that class of customer, or during the day of the highest system load. An analyst may use average weekday or average day load curves to show patterns that are relatively unaffected by chance variations.

LOAD STUDIES

Load studies reveal important characteristics such as: average and maximum noncoincident one-hour demands, which are important in designing distribution systems; maximum diversified one-hour and twenty-four hour demands, which affect production, transmission, storage, and purchased gas requirements; and load factors as well as gas consumption for the various periods. The variation of these elements of load can be correlated with weather, customer characteristics, and economic variables.

Load curves and data on diversities, maximum demands, load factors, etc., provide information and insights to utility managers for making decisions and solving problems. Some more important uses of load studies are:

- Economic and Rate Studies
  - Estimating cost of service by class of service
  - Designing rates for different classes of service and by time of day and season
  - Calculating rate of return by class of service
- Energy Management
  - Identifying loads which, if modified, would improve system operations
  - Estimating customer energy costs for new processes and new or additional equipment
  - Planning conservation and curtailment
- Engineering Studies
  - System planning of production, transmission, storage and distribution plant
  - Planning service facilities for newly developed territories
  - Determining service pipe and meter sizes
- Load Forecasting
  - Estimating system maximum hourly and twenty-four hour demands for budgeting and purchasing gas requirements
  - Normalizing customer use for weather and other variables.

LOAD TESTING METHODS

Recording meters are used to measure variations in gas consumption. Such meters can be installed to measure the combined load of a group of customers, individual customers, or specific appliances. Selected area or group-metered tests determine the characteristics of a group of customers within a self-contained area by metering gas consumption at a common point in the distribution system. This method, for

example, has been used to determine the space heating load characteristics of a group of homes. When this method is used, the homes in the selected area should vary in size, quality, and type to represent a cross section of all types of homes within the utility's service area.

This method has limitations because it measures only the *total* demand of a group of customers. To quantify the amount and characteristics of the heating use alone would require an estimate of the base load (i.e., other than space heating). Moreover, the usefulness of the data will depend on the degree to which the selected area is representative of all such customers. It is often difficult to find areas containing only the particular type of customers desired for the tests. However, if a given area is otherwise suitable, it may be possible to meter the individual customers having undesirable characteristics and subtract their data from the group total. The major advantage of the group-metered test is the minimum investment in test meter facilities and the low cost of processing the data. Individually metered tests are another method. When the loads under consideration are common to a large number of customers, sampling procedures can be used to reduce the cost of the study and still obtain valid and meaningful results. Validity will depend on the selection of an unbiased sample of customers. Statistical sampling makes it possible to quantify the characteristics of a class of a million or more customers using data from a carefully selected sample of two or three hundred (or often much fewer) customers. Careless selection, of course, would produce seriously biased data, even with samples many times larger.

STATISTICAL SAMPLING

Statistical sampling involves randomly selecting test customers in a way that gives each customer in a specified group an equal and known probability of being included in the sample. Two techniques commonly used are simple random sampling and stratified random sampling. In the former, the entire population of customers is considered as one group. Each customer has the same probability of being selected for the sample. In stratified random sampling, the population is divided into several relatively homogeneous groups or strata. Different sampling probabilities (or fractions) can be used in each stratum. Computer programs can be used for either type of sampling. Alternatively, a comparatively simple technique called systematic sampling can be used.

Both simple random sampling and stratified sampling can yield a reliable picture of the population from which the sample was drawn. From these customers in the sample, estimates of population charac-

Chapter 8
Fundamentals of Utility Pricing

Technical Editor: Robert H. Sarikas, Foster Associates

The rates of a gas utility are the prices charged for the utility's service. These prices, together with the rules and regulations that govern the rendering of service, are usually subject to regulation by state/provincial and federal commissions and in some cases by municipalities.

Regulation defines the rights and duties of the customers and the company. As a public utility, the principal obligation of a company is to provide gas service to all customers who request it at reasonable rates without undue discrimination. In return, the regulated public utility receives the following: the opportunity to earn a fair return upon the value of the utility's property; a service franchise or certificate rights in the utility's area of operation; and the right of eminent domain and use of public ways.

PRICING THE SERVICE

Once a regulatory body has approved a rate or condition of service, it may remain in effect for a short time or for many years. The better a rate schedule fits a particular situation (i.e., allowing satisfactory earnings for the utility while encouraging the efficient use of gas service by the company's customers), the better for all concerned.

The difference between utility rate setting and the pricing of other commodities reflects the difference between two kinds of markets. Typically, economists classify markets by the relative degree of competition that exists within them. A gas utility, for example, is assured of a market (service territory) free from competition by other gas suppliers, but one which is not free from competition *per se*. Gas distribution utilities face competition from other sellers of energy, such as electric utilities, which are also regulated, and from unregulated coal, oil,

and liquefied petroleum gas dealers that are free to bargain for available business. A gas distribution utility must also compete with all types of goods and services for a share of its customers' disposable income.

Unlike competitive market prices, which result from the interaction of supply (by many firms) and demand (by many customers), utility rates are administered and set by a regulatory agency. The objective of rate regulation is to set the rates paid by consumers at levels sufficient to provide the utility with enough revenues to cover the costs incurred in providing a reasonable quality of service and, at the same time, allow the company the opportunity to earn a fair return on the capital employed.

Utility ratemaking is not an exact science. A "technically correct" rate structure covers the total costs of serving the customers, including an adequate return to the utility. Cost is an important guide in ratemaking, but in practice rates are designed within a framework that includes many factors in addition to costs. These include: economic, regulatory, supply, social, and political considerations. A well-designed rate reflects the importance of these other factors.

RATE OBJECTIVES AND METHODOLOGIES

It is important to distinguish between rate *objectives*, ratemaking *methodologies*, and rate *forms*. The following are some typical objectives of rate design:

- Achieving the revenue requirement
- Economic efficiency
- Fairness or equity
- Simplicity and administrative ease
- Conservation of resources
- Stability and gradualism
- Social goals
- Environmental protection
- Employment
- Balance of payments

Ratemaking objectives often conflict, requiring regulators and utility rate experts to balance objectives and functions rather than try to realize a single overriding objective.

According to James Bonbright, the four *primary* functions of public utility rates are:[1]

[1] James C. Bonbright, *Principles of Public Utility Rates*, (New York: Columbia University Press, 1961), p. 49.

- Capital attraction
- Efficiency
- Demand control or consumer rationing
- Income distribution

Methodologies of cost analysis include various types of embedded or fully distributed cost studies, marginal and long-run incremental cost analysis (LRIC), and value of service. Rate forms include flat rates, declining block rates, inverted rates, and Hopkinson and Wright demand rates. These costing methodologies and rate forms are the basic tools of cost of service analysis and rate design.

These tools are used to achieve one or more of the objectives of ratemaking. For example, fostering economic efficiency through rate design would involve the use of marginal cost analysis. Achieving the goal of fairness, particularly if fairness is defined as giving significant weight to allocated costs, may require the use of one of the numerous methods of capacity cost allocation. Emphasizing social goals would suggest a consideration of lifeline rates or special discounts. Thus, costing and rate design methods themselves are not right or wrong *per se*. They are only proper or improper, measured in terms of their usefulness in attaining the desired objectives.

The Revenue Requirement

Meeting the utility's annual revenue requirement is a singularly obvious goal of ratemaking because continued service and providing for expansion require an equality of revenue and revenue requirements. By definition, a fundamental purpose of pricing is to provide sufficient revenue to cover the firm's expenditures. This goal can be extended to include ratemaking that ensures continuing profitability such that the need for subsequent rounds of rate increases is mitigated.

Economic Efficiency

Economic efficiency requires a proper reflection of cost in price so that a utility customer's purchasing decisions result in an efficient allocation of resources. Pursuing the goal of economic efficiency implies that marginal cost analysis would be used. Economic theory holds that prices based on short-run marginal costs lead to an optimal allocation of resources. If, for example, gas service is priced lower than that amount, users would be encouraged to use more of that service, resulting in an inefficient allocation of resources.

As a substitute for competition, one purpose of regulation is to achieve the *results* of competitive markets. Therefore, establishing

regulated utility rates (i.e., prices) at a level that would exist in a free and competitive market place should enhance economic efficiency.

Conceptually, marginal cost is the change in total cost as output increases. At a practical level, various techniques exist to perform marginal cost analyses. For example, the marginal cost of gas supply could range from the cost of incremental purchases for each retail rate class under the applicable tariff of a sole pipeline supplier to incremental cost changes calculated by use of an optimal gas supply program on the basis of multiple pipeline suppliers plus underground storage and peaking service. In each instance, the analyst must determine the *added cost* of an added increment of sales.

If prices are equated to the marginal cost for each rate class, the revenue derived with prices equal to marginal costs can be estimated. Revenue calculated on that basis may be more or less than the allowed revenue requirement under conventional (i.e., embedded or fully allocated) cost of service ratemaking. The revenue derived from marginal cost-based rates can be scaled up or down to match the revenue requirement calculated by conventional means. This scaling can be on a *pro rata* basis or inversely proportional to the relative price elasticity of demand of the customer groups (i.e., "Ramsey" pricing). Results of a marginal cost study can be used for rate design for a particular rate class even though class revenues are established on the basis of an embedded cost of service study.

Fairness or Equity

Most people believe that a rate based on the cost of providing service is fair. The goal of fairness is frequently mandated by statute although no definitive standards exist. If such an objective of pricing is statutory, it may constrain the attainment of other goals.

Costing could be based on embedded or marginal cost. In some cases, however, pricing to enhance economic efficiency may conflict with the fairness goal. For example, while a market clearing price may be the most economically efficient method of handling a shortage, rationing or a "first-come, first-served" basis may be fairer. In any event, the traditional utility pricing approach that recognizes fairness as a goal bases class revenues—and to a lesser degree rate design within a rate class—on embedded or allocated cost of service.

Simplicity and Administrative Ease

The goal of simplicity implies rates that should be easily understood (i.e., the user can determine the expected cost of service). Simple rates

minimize the need for employee and customer education as well as reduce record keeping and administrative costs.

Conservation of Resources

Conservation of resources or the prevention of waste is closely akin to economic efficiency. Conservation also means avoiding the use of energy that is worth less to consumers than its cost to society. Conservation could also be defined as using less of a natural resource today so as to have more to use in the future when it may have a higher economic value.

Stability and Gradualism

The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operations are minimized.

Stability of revenues is important to the utility because budgets must be met. At one extreme, in terms of rate design, revenue stability would be maximized if all costs were recovered by a fixed customer charge or ratcheted demand charge. The commodity charge would be zero. If sales volume fell, the utility would still recover all of its costs. In a period of sales increases, revenue growth would be enhanced if the highest price were applied to the fastest growing parameter (i.e., demand or commodity) with the other priced at zero. Of course, such a rate approach would not receive regulatory approval. Obviously, the pricing pattern required to achieve revenue stability may conflict with other ratemaking goals.

Social Goals

Social ratemaking goals involve rate designs that advance the welfare of a particular group in society. For example, utility "lifeline" rates can reduce the impact of rate increases on customers least able to pay for gas service, such as persons on fixed incomes. For such customers, higher utility prices may mean a significant decrease in well-being. Nevertheless, subsidies for one group, regardless of its need, mean shifting the economic burden to others.

Utility pricing policy decisions can be judged against the results that would occur if similar policies were pursued in competitive markets. Under this standard, utility customers would be treated in nearly the same fashion as would be the case under competition. Utility pricing schemes that constitute a redistribution of wealth reflect the political process rather than administrative regulation.

Environmental Protection

Rates that are economically efficient will optimize the use of scarce resources and, by definition, minimize adverse environmental effects. Thus, to a great extent, this objective parallels the goal of economic efficiency.

Employment

Given that full employment is an important national objective, gas utility rates that enhance the prospect of employment serve an essential purpose. Nondiscriminatory rates for industry that both attract new business and retain existing employees might be viewed as enhancing this goal.

Balance of Payments

The balance of international payments is a vital national economic and political concern. Pricing that minimizes the use of imported fuels could be regarded as an important objective.

VALUE OF SERVICE

Utility rates that reflect competitive factors are often called value of service rates. Value of service is shorthand for the highest price that a single customer is willing or able to pay for service. That price depends, in part, on the price and availability of alternative service (e.g., fuel oil, coal, etc.). With respect to an entire rate class, value of service can be defined as an area under an economist's demand curve (i.e., the social benefit obtained from the particular service). Some critics characterize rates based on value of service as charging "what the traffic will bear."

Chapter 9
Rate Forms

Technical Editor: Robert J. Hobday, Rochester Gas & Electric Corporation

Most rates for small retail consumers are based on the volume (i.e., cubic feet) of gas service provided. Such rates are simple in form and are often referred to as commodity rates. Rates based on *both* the customer's volume and demand-use characteristics are known as demand rates. These more complex rates are usually applicable only to very large volume industrial service customers.

Most gas rates are stated in terms of a volume (e.g., so many dollars per 1,000 cubic feet (Mcf)). Some companies, however, bill on a therm basis.[1] Under this method, rates are expressed in terms of the number of heat units delivered instead of the volume of gas metered.

FLAT RATE

The flat rate is the earliest and simplest rate form (see Figure 9–1). Under this rate, which was widely used before the advent of metering, customers are assessed a flat charge per unit of time (e.g., dollars per day, week, or month). The charge is based on a use-factor proxy (e.g., the hourly demand of gas-burning equipment served). Although this rate form is simple and easily administered, it is flawed. A flat rate results in the same monthly bill for customers using their equipment infrequently and customers using the same kind of equipment more fully during the billing period. This rate form is outmoded except where a customer's use is constant or follows a fixed pattern at a known consumption level (e.g., decorative residential gas lights).

[1] A therm of gas contains 100,000 Btus of heat. Ten therms, or a decatherm, contain the approximate heat content of 1 Mcf of gas.

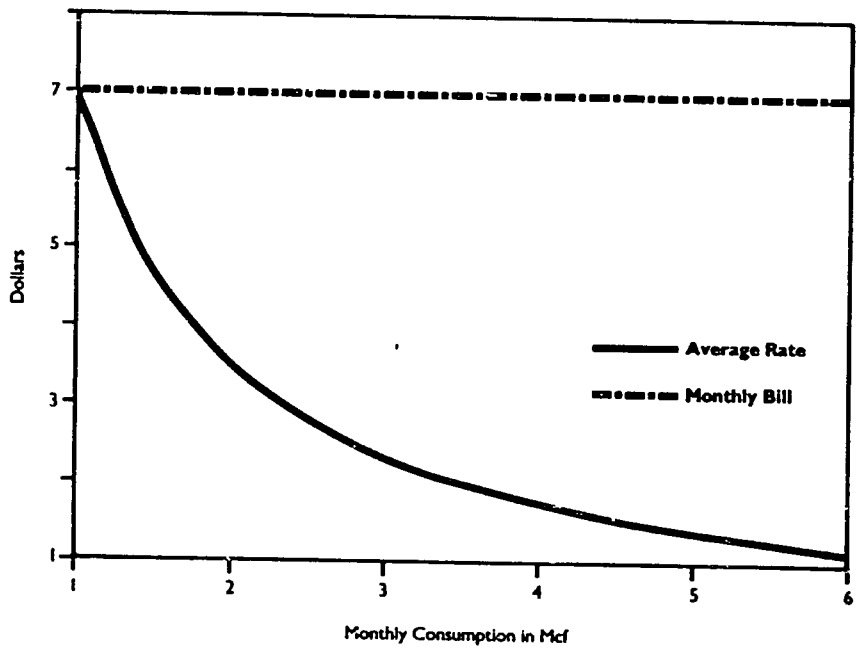


Figure 9-1. **Illustrative flat rate**

STRAIGHT LINE METER RATE

With the advent of metering devices, a number of rate forms that rely on the measurement of actual use were developed for billing purposes. The first of these, the straight line meter rate, has a constant price per unit of gas consumed, as recorded on the customer's meter (see Figure 9-2), regardless of the volume consumed. This rate form is the simplest of all the meter rates. It derives its name from the straight line that results when the total bill for various usage levels is plotted on a graph. This rate form was used by gas companies to bill water heating, cooking, and refrigeration. More recently, it has been used by pipelines as a "volumetric rate." The straight line rate has the advantage of billing based on a customer's actual use and, therefore, is not as discriminatory as the flat rate. Its disadvantage is that costs are recovered at a uniform rate solely in proportion to the volume of gas use. If, for example, a customer had no use in a month, the bill would be zero. Yet, the utility would have incurred costs in reading that customer's meter and in paying the continuing fixed charges on the utility's investment in facilities needed to serve that user. The company's other customers would have

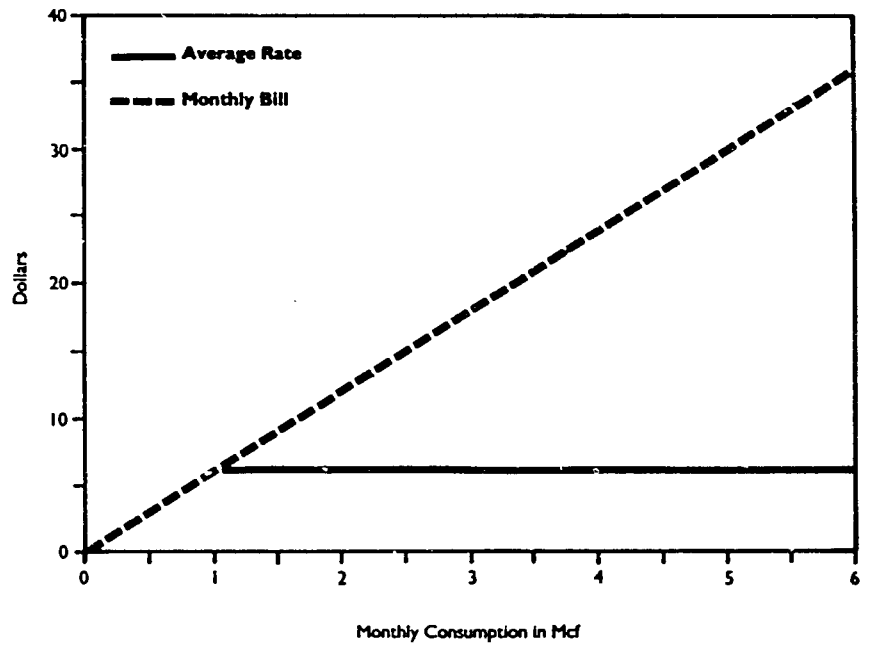


Figure 9-2. **Illustrative straight line meter rate**

borne these costs or the utility might have underrecovered its revenue requirement.

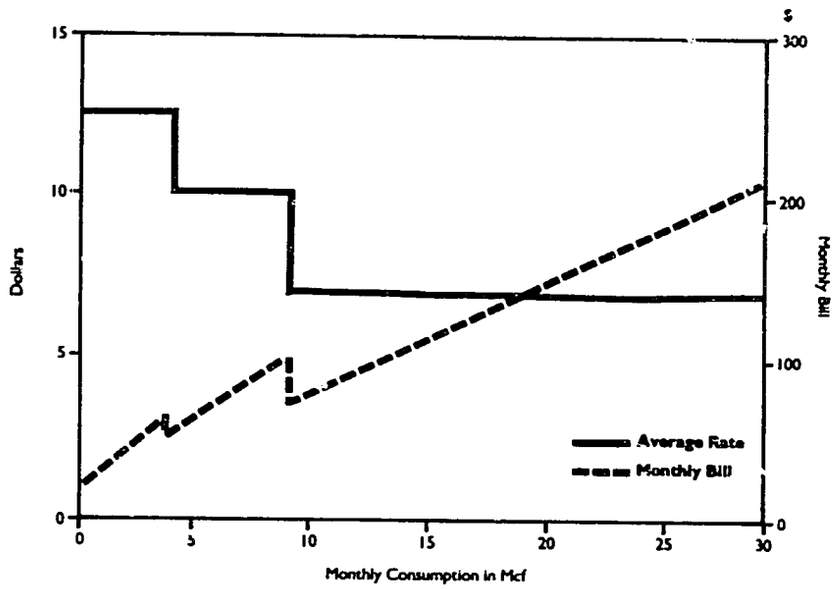
The straight line rate form can be improved by including a customer charge (or service charge). This charge permits the utility to recover at least a minimum amount of revenue from its low-use customers. Another less controversial approach involves a minimum charge. This entitles the customer to a small amount of gas use without additional charge. The following are examples of these two features using the "block meter" rate form described later in this chapter:

- Customer charge per month ..... $ 5.00
  First 2.5 Mcf used per month ..... $12.50 per Mcf
  Next 7.5 Mcf used per month ..... $10.00 per Mcf
  Over 10.0 Mcf used per month ..... $ 7.00 per Mcf
  Minimum monthly bill is $5.00 per meter.
- First 0.3 Mcf or less used per month ..... $ 5.00
  Next 1.2 Mcf used per month ..... $12.50 per Mcf
  Next 8.5 Mcf used per month ..... $10.00 per Mcf
  Over 10.0 Mcf used per month ..... $ 7.00 per Mcf
  Minimum monthly bill is $5.00 per meter.

STEP METER RATE

Under this rate form, the customer's entire volume of use is billed at a certain price, which varies depending upon the rate "step" in which *total* metered use falls (see Figure 9-3). This rate differs from the flat rate and the straight line meter rate in two ways. First, the step meter rate encourages customers to increase use to obtain the lowest unit price available; this helps the utility achieve a higher overall load factor than would otherwise prevail. Second, because the low-volume or convenience gas user pays a higher unit price than the large-volume customer, this rate form tracks more closely the costs of providing service. An example of the application of this rate form is shown in Figure 9-4.

The step meter form has two objectionable features. First, some bills for large use could be lower than bills for smaller use. For example, using the rate shown in Figure 9-3, the billing for 5.5 Mcf (at the second step) would be $55.00. Yet, the billing for 4.9 Mcf (at the first step) would be $61.25. Such a situation is illogical and unfair. Moreover, it might encourage customers to waste gas just to obtain a lower price. Second, the step meter rate discriminates against high load factor customers with small consumption while favoring large-use customers even if they have lower than average load factors. These latter customers



Monthly Consumption (Mcf)	Entire Consumption Billed (Per Mcf) at:
Under 5.0	$12.50
5–10.0	10.00
Over 10.0	7.00

Assume monthly consumption is 8 Mcf. The bill would be $80.00 or 8 Mcf times $10.00 per Mcf.

Figure 9-4. **Sample application of the step meter rate**

are not charged their fair share of the fixed costs of the facilities required to serve them.

BLOCK METER RATE

The undesirable features of the step meter rate were ameliorated by the introduction of the block meter rate (see Figure 9-5). This rate has two or more successive blocks of use with decreasing prices per unit of volume.[2] *Unlike* the step rate, however, the customer is billed for use in each successive block at the rate applicable to that block. The charges calculated for each block are then added to determine the total monthly bill. Rates of this type are usually designed to recover a substantial portion of customer costs in the initial block. Block meter rates are widely accepted because they are simple and avoid undue discrimination as well as recognize that some cost elements decrease on a unit basis, as use increases. A sample application of the block meter rate is shown in Figure 9-6.

The price for gas usage in each block can recover some share of capacity (fixed) costs as well as commodity (variable) costs. The follow-on blocks are usually priced closer to commodity costs. In the past, this cost-related rate design helped gas compete with other fuels in energy markets. The higher-priced initial rate blocks covered various combinations of low-use appliances while the lower-priced terminal rate blocks encouraged additional gas usage (e.g., space heating). A few years ago, the emphasis on energy conservation prompted the design

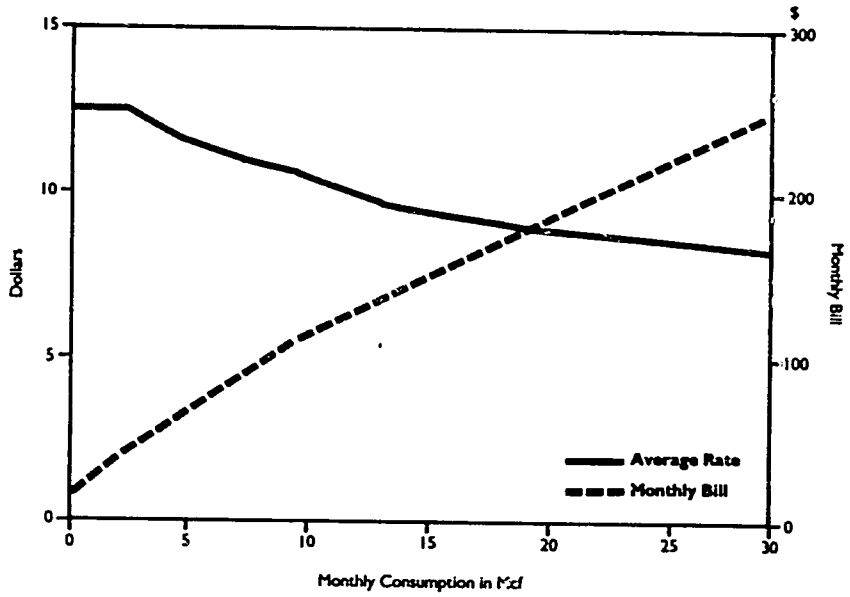


Figure 9-5. **Illustrative block rate**

of rates with fewer blocks and having smaller price differentials between blocks. In some jurisdictions, two-step block rates were adopted to discourage "unnecessary" or "wasteful" consumption. The appropriateness of such rate designs is debatable when other ratemaking objectives, such as reflecting costs, are considered.

Because load factors are fairly uniform among residential customers, a block meter rate can recover customer, capacity, and commodity costs for the residential class on an equitable basis. Large-use commercial and industrial customers, however, exhibit a much wider range of load factors, thus, some inequities could occur. The block meter rate also tends to be discriminatory against high load factor customers with small use while favoring large-use customers even though they may have lower than average load factors. Under this rate form, the high load factor customer tends to pay for a relatively larger share of the fixed charges on production, transmission, storage, and distribution plant.

A rate form known as reverse blocking or the "inverted rate" has been used to encourage usage at a more favorable load factor. Such rates can be designed to collect higher charges for greater usage in *colder* months, which contributes to a poorer load factor. An example

Monthly Consumption (Mcf)	Billed at: (Per Mcf)
First 3.0	$12.50
Next 7.0	10.00
Next 20.0	8.00
All additional	7.00

Assume monthly consumption is 31 Mcf. The bill is computed as follows:

First	3.0 Mcf @	$12.50 per Mcf	= $ 37.50
Next	7.0 Mcf @	10.00 per Mcf	= 70.00
Next	20.0 Mcf @	8.00 per Mcf	= 160.00
Remaining	1.0 Mcf @	7.00 per Mcf	= 7.00
	31.0 Mcf		
		Total Bill	$274.50

The average price of gas is $8.85 per Mcf.

Figure 9-6. **Sample application of the block meter rate**

of a general service gas rate for large users that embodies a low load factor adjustment provision is shown in Figure 9-7.

An inverted rate form variation to the basic block meter rate is the "lifeline" rate. Proponents of this form contend that every residential customer should receive an amount of gas service adequate to meet basic human needs for survival in modern society (hence, the name "lifeline"). This volume would be at a price that all customers could afford, especially those families living in poverty. Lifeline rates, which establish a low-price initial block that is below the cost of service, shift cost burdens to other residential users above the lifeline consumption level and, perhaps, to other customer classes. Lifeline rates reflect social objectives as a basis for ratemaking in addition to the more traditional rate design goal of cost responsibility. The adoption of lifeline rates has been limited.

DEMAND RATES

Because of the greater variance in the load characteristics of large-use customers, gas distribution companies and pipelines prefer rate forms that take into account a customer's demand and load factor. Demand, or two-part rates, impose a *demand charge* based on the customer's

Rate

For the first 100 Mcf used per month ..... $7.00 per Mcf
For all over 100 Mcf used per month ..... $6.00 per Mcf

Adjustment for Low Load Factor

For all gas consumed in the billing periods for November through May in excess of 1.1 times the average amount of gas used per month, June through October immediately preceding ..... $3.00 per Mcf

Figure 9-7. **Sample application of gas rate with low load factor adjustment**

maximum demand. This feature also establishes the utility's responsibilities to provide a certain maximum level of service. There is also a *commodity charge* based on total usage during the month.

A customer's demand is defined in terms of usage within a specified time interval. For example, if one customer uses 1 Mcf per day while another customer uses 2 Mcf per day, the latter's demand imposes a responsiblity on the utility system twice that of the former. Demand may be determined by metering or by the nameplate ratings of connected loads of gas-consuming appliances and equipment.

Demand rates are not used extensively by gas companies for two reasons. First, demand meters are costly. Second, periodic inspections of customers' premises to check connected equipment capacity are also expensive. Other deterrents to the use of two-part rates involve the complexity associated with demand-rate billing and the adverse reactions of customers. They have difficulty understanding or accepting the demand concept. When demand rates are used, it is usually for large-use customers because they can grasp the need for such a rate form.

Demand may be expressed on an hourly or daily basis. Most distribution companies purchase gas from pipelines under a demand rate, with demand determined on a daily basis. Where the distribution utility's customer is located at a considerable distance from the source of supply, hourly demand is an important consideration because the capacity of a distribution main is figured on an hourly basis. Thus, maximum hourly consumption is reflected in the design of demand rates for distribution system customers.

Demand rates can incorporate a "ratchet" clause. This would stipulate that a customer's *billing* demand cannot be less than a stated percentage (sometimes as high as 100 percent) of *maximum* demand during a previous period (usually twelve months ending with the current billing month). Because a utility must have adequate facilities standing ready at any time to serve a customer, a ratchet forces a customer to pay fixed charges related to the maximum demand imposed on the system. The ratchet protects the utility and benefits high load factor customers. Customers with a low annual load factor are required to bear their share of capacity costs, as imposed by their peak demands, even though their use at such a high level is very infrequent.

Demand rates have two basic forms: the *Hopkinson* demand rate and the *Wright* demand rate.

Hopkinson Demand Rate

The Hopkinson demand rate was devised in 1892 by Dr. John Hopkinson, an Englishman. The Hopkinson rate contains a demand charge and a commodity charge – it is a "two-part rate." Pipelines use the term "demand-commodity rate." In distribution utility rates, the separate demand and commodity charges are usually blocked. Sometimes, the commodity charge has a Wright feature (as described below) in one or more of the blocks. In pipeline rates, the demand or commodity charges are rarely blocked. Figure 9-8 shows the relationship between

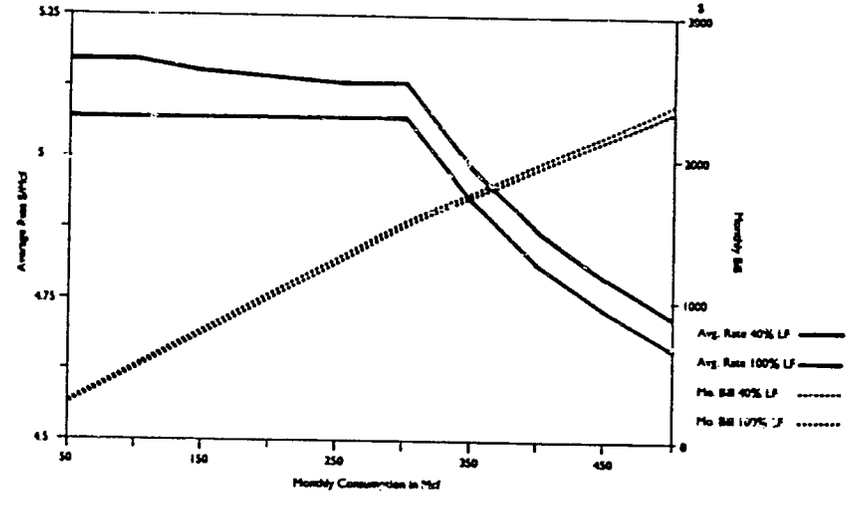


Figure 9-8. **Illustrative Hopkinson demand rate**

without the use of separate demand and commodity charges. Figure 9-12 shows a sample application of the Wright demand rate.

With a Wright demand rate, a customer pays no more for service received through several separately billed meters than if the same total amount of gas were received through a single meter (unless the rate is blocked and suitable maximum demands are specified).

Under a Wright demand rate, a customer can decrease the average rate only by improving load factor. This is shown by the curve in Figure 9-13, which illustrates the relationship between the average rate and load factor. The average rate is not affected by a change in use if load factor remains constant.

VARIABLE RATES

Recently, vigorous price competition between natural gas and other fuels has lead to gas rates that are tied to and vary with the price of alternate fuels. These variable rates generally follow traditional rate forms. For example, one such rate has declining blocks with the tail-block for sales in excess of 10,000 Mcf per month based on the equivalent price of No. 6 residual fuel oil. The utility can adjust the tailblock rate monthly. The tailblock rate is constrained by a stated *floor* price, the rate of the penultimate block is a *ceiling* price. This type of rate allows a gas company to compete more effectively and, perhaps, retain large volume dual-fuel customer loads.

First 3 cu. ft. per cu. ft. of max. daily demand	$12.50 per Mcf
Next 17 cu. ft. per cu. ft. of max daily demand	$ 9.00 per Mcf
All addt'l use per cu. ft. of max. daily demand	$ 7.00 per Mcf

For a customer with a maximum daily demand of 20 Mcf and a monthly consumption of 420 Mcf (70 percent load factor, assuming a 30-day month), the bill is computed as follows:

First 3 cu.ft.×20 Mcf =	60 Mcf @ $12.50 Mcf =	$ 750.00
Next 17 cu.ft.×20 Mcf =	340 Mcf @ $ 9.00 Mcf =	3,060.00
Remainder =	20 Mcf @ $ 7.00 Mcf =	140.00
	Total Bill	$3,950.00

The average price of gas is $9.40 per Mcf.

Figure 9-12. **Sample application of the Wright demand rate**

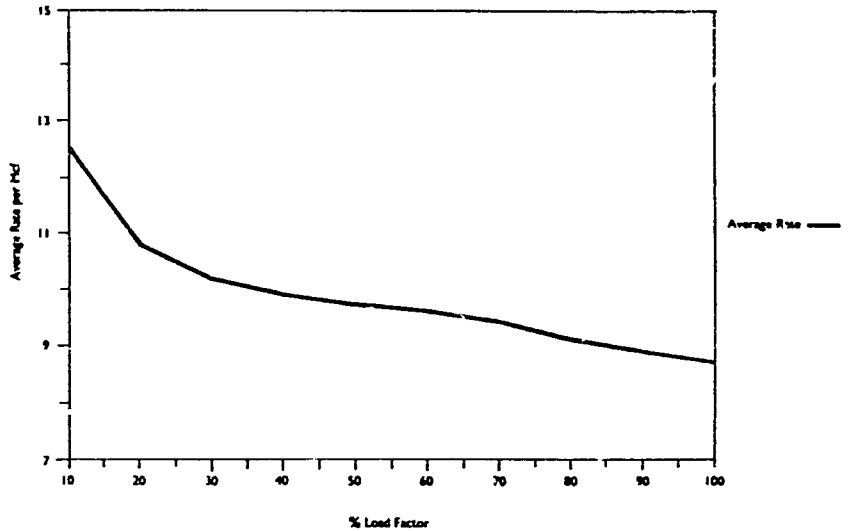


Figure 9-13. **Wright demand rate relationship between load factor and average rate**

MINIMUM, SERVICE, AND CUSTOMER CHARGES

Rate schedules contain other provisions. For example, even if a customer uses no gas, a rate schedule should provide some means of recovering those costs that are independent of the use of gas (e.g., the costs of meter reading and billing and fixed costs on plant and equipment). One such device is a service or customer charge. These consist of a flat monthly charge in addition to the charges for gas use. Frequently, the service charge is based on a demand factor, such as burner capacity. Many customers, however, do not understand or like a service charge. Utilities have failed to convince customers that they should pay for "readiness to serve," as well as for the volumes of gas used. This has led many utilities to adopt minimum charges in lieu of service charges. The minimum charge, in most cases, involves the initial block of the rate. This would cover a small volume of gas service, ranging from 0.1 to 1.0 Mcf per month.

For small-use customers, meter reading and billing are a proportionally higher part of the total cost of service than for large commercial or industrial customers. For such larger users, the fixed costs of the utility's plant are more important. Therefore, where demand charges are included in a rate, they are like a minimum charge because they cover the fixed costs associated with the investment needed to serve those customers. In many rates, minimum demand charges are a means of providing a ratchet provision.

PRICE ADJUSTMENTS

In the past, gas distribution companies experienced reductions in earnings because of the delay between the date of filing for a rate increase and the date when increased rates became effective. The financial strains caused by this "regulatory lag" led many state regulatory commissions to allow utilities to incorporate price adjustment provisions in their rates. These permitted gas rates to fluctuate in response to certain specifically defined costs without the need for time-consuming formal rate-case proceedings. Such adjustment provisions are limited to major elements of operating costs – generally those beyond the control of the gas utility. Adjustment clauses are usually designed to provide for both increases and decreases above or below a specified base cost level, which is the level of costs that the utility's basic rate schedules are designed to recover. In some jurisdictions, rate adjustments by the utility can be made effective by notifying the commission. In other states, rate changes under the adjustment provision require the utility to apply for specific approval by the commission.

Price adjustment clauses customarily include three elements: (1) the base cost level, (2) the "change step," which is used to measure variations from the base cost level, and (3) the "factor of adjustment." The factor of adjustment is the amount the charge is increased or decreased for each unit step of change above or below the base cost level. Some clauses provide for a neutral zone on both sides of the base cost level. Fluctuations within this zone cannot trigger the operation of the adjustment clause.

Today, various price adjustment provisions are in general use. For example, in some gas-producing states, utilities use a field price adjustment that is linked to a base purchase price for gas in the field. Any increase or decrease in the field price is reflected in an automatic increase or decrease in charges to customers. This adjustment is generally limited to large, separately classified users.

A purchased gas adjustment (PGA) provision is in general use by gas distribution utilities that buy a large portion or all of their requirements from pipelines. The PGA permits an automatic adjustment when the cost of gas goes above or below a specified base cost. Also, this provision often is used to return a proportionate share of refunds received by the utility from a pipeline when its rate is retroactively reduced by an order of the FERC. Because of the inherent lag in many PGA clauses and the possibility of rapid change in the price of gas, the problem of cost recovery can be substantial. Therefore, some firms are allowed to charge on the basis of the *estimated* cost of gas for the

month (or longer period) billed. When *actual* costs are known, reconciliation is made. This procedure eliminates the financial burden caused by billing lags.

A competitive fuel adjustment clause may be used in large-volume gas rates. This adjustment is made in reference to *current* fuel oil prices in relation to a *base* price of oil at the time when the utility's rate schedule for gas service became effective. For most industrial and large commercial rates, the adjustment would be based on prices for heavy oil (e.g., No. 6). For some space-heating rates, the adjustment is linked to light heating oil (i.e., No. 2) prices.

A commodity index adjustment provision permits compensating price changes in response to general increases or decreases in wage rates and the costs of materials used by the utility in its operations.

A tax adjustment provision enables a utility to adjust its gas rates for increases and decreases in specific taxes levied by public authorities. Taxes covered by such provisions may be those classified as production, transportation, excise, severance, occupation, street rental, or gross receipts.

A Btu or heat-content adjustment provision in volumetric rate schedules adjusts customers' bills for variations (relative to an established base) in the actual heat content of the gas delivered. This adjustment can be accomplished in two ways: (1) by adjusting the metered volume to an equivalent volume at the base heating value, and (2) by adjusting the effective rate levels above or below the authorized base rates by a formula that recognizes the actual average heating value. A heat-content adjustment provision is logically included in a distribution utility's rates if the company purchases gas from its suppliers under similar rates.

Many heat-adjustment clauses specify a range within which *no* adjustment is made. This avoids confusing customers with complicated billings. A company, for example, may stabilize its rates for gas between 1,000 and 1,025 Btus. No rate adjustment is made when the heat content varies within these "neutral zone" limits.

By definition, therm rates do not require adjustments for Btu variations. Such rates, however, do require calorimeter readings and the application of a therm conversion factor to determine the quantity of therms to be used for billing purposes.

Cost of service-adjustment provisions are included in the rates of some pipelines for the sale or transportation of gas to affiliated companies. These rates are based on a formula that includes a specified rate of return. The provisions adjust rates to compensate for changes in a pipeline's cost of service. A few gas distribution utilities

also have this type of adjustment clause in their rates. Such rates are often based on specific city ordinances where "home rule" is applicable.

REFUND PROVISIONS

Utilities may make refunds to customers because of retroactive reductions in the prices paid for purchased gas or by gas rates that were put into effect subject to refund and that were subsequently reduced by a regulatory agency. If a purchased-gas adjustment provision is in effect, refunds from a pipeline are passed on to customers by adjustments to the amount of purchased-gas adjustment billed in a subsequent period until the total amount of refund has been made. Although this type of refund may not be completely accurate for an individual customer, it is easy to administer and is often the only practical method. As long as the pattern of a customer's usage from month to month and season to season is relatively constant, this method accomplishes its purpose reasonably well.

There are no hard and fast rules in cases where revenues have been collected pursuant to rates subject to refund. A regulatory authority instituting lower rates will usually require that differences between bills rendered under the superseded higher rates and under the final rates be refunded to customers. The manner of refund is often negotiated in conferences between the utility and the regulatory authority. For residential and small commercial customers, a comparatively simple and approximate refunding on future bills may be adopted. For large commercial and industrial customers, actual past bills can be recalculated under both sets of rates and any differences refunded.

GAS RATE FUNDAMENTALS

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Chapter 12
Pipeline Cost Allocation and Ratemaking

Technical Editor: Kenneth R. Smathers, National Fuel Gas Supply Corp.

The cost of gas purchased from pipelines represents by far the major portion of the total cost of service of a gas distribution company. Therefore, understanding pipeline costing and ratemaking philosophy and methodology is an important consideration in retail ratemaking. Many of the basic ratemaking theories, principles, ideas, practices, and philosophies are equally applicable to both segments of the gas industry.

THE NATURAL GAS ACT

Pipeline ratemaking, as it is understood today, had its genesis in 1938 with the passage of the Natural Gas Act.[1] This law gave the Federal Power Commission (now the Federal Energy Regulatory Commission) the authority to regulate the transportation and sale for resale of natural gas in interstate commerce. Section 4 of the Natural Gas Act (NGA) specifies that all rates, charges, contracts, rules, and regulations subject to the jurisdiction of the Federal Energy Regulatory Commission (FERC) shall be just and reasonable. In addition, the law provides that undue preference or advantage shall not be granted to any person. Every natural gas company must file and post its rate schedules as well as its regulations and contracts pertinent to such rate schedules.

Section 4 also provides for the filing of changes in rates, charges, contracts, rules, and regulations. These rate changes take effect after thirty days' notice unless the FERC suspends them for a period not to exceed five months. Upon expiration of the suspension period, a utility can place the new rates or provisions in effect subject to refund. If

[1] 15 U.S.C. S 717, et seq.

the change is suspended, the FERC conducts a hearing to determine the lawfulness of such a change. At the hearing, the burden of proof is on the natural gas company to show the reasonableness of the change.

Section 5 of the NGA, however, empowers the FERC to investigate, either upon its own motion or upon complaint, the lawfulness of any rate, charge, regulation, contract, or part thereof subject to its jurisdiction and to determine the just and reasonable rate.[2] The FERC can order a change if existing rates are found to be unjust, unduly discriminatory, preferential, otherwise unlawful, or are not the lowest reasonable rates. Under this section, the FERC cannot order into effect rates higher than those previously on file unless the higher rate is in accordance with a new schedule filed by the company. This latter provision was intended to allow pipelines to establish rates for industrial uses of gas at levels competitive with the prices of other fuels.

FERC GENERAL RULES AND REGULATIONS

The NGA prescribes no set procedure for rate hearings or rate administration by the FERC. Section 16 of the Act grants the FERC the power to prescribe such rules and regulations as it may find necessary to carry out the provisions of the NGA. These procedures are specified in the FERC's General Rules and Regulations.[3]

When a rate schedule constitutes a new rate for a new service, its initial filing is not subject to suspension. In such cases, the Rules prescribe only the form, general content and supporting schedules that the company must file. The utility must provide the reasons for the rate schedule, the basis of the proposed rate or charge, and an estimate of the expected sales and revenues. This new service must be certificated under Section 7 of the NGA. A certificate may include rate conditions.

The Regulations require relatively little data in support of minor tariff adjustments[4] and changes in terms and conditions not considered to be an increase in rate levels. If, however, a *major* increase in rates is involved, a voluminous amount of supporting data are required. The preparation of data, organization into the proper form, and

[2] Under Section 5, the burden of proof is not imposed on the utility as is the case under Section 4. As a practical matter, the company can be called on to defend the propriety of its effective tariff.

[3] 19 Code of Federal Regulations 1.1, et seq.

[4] The FERC defines minor changes as including ". . . changes that are not designed to provide general revenue increases such as to offset increased costs or otherwise achieve a fair return on the overall jurisdictional business." (Regulations Under the Natural Gas Act. Section 154.63(a)3.)

reproduction of multiple copies takes a considerable effort in time and resources.

After the FERC receives the company's filing, the Commission has thirty days to analyze the data to determine whether or not the increase is justified. If the FERC finds in the affirmative, it may allow the rates to become effective as proposed. If the Commission is not convinced that the increase is justified, the FERC may suspend the proposed rate for a period of up to five months beyond the time when the rate would otherwise have gone into effect. Practically speaking, the latter is the rule for a general rate increase.

The former is a rare exception, unless the filing involves a routine tracking of purchased gas costs pursuant to an approved tariff provision. The company usually places the higher rates into effect subject to refund, pending final resolution of the rate proceeding. This is prudent because it is seldom possible to process an application, conduct an examination of the company's books and records, hold a hearing, file briefs, render an Administrative Law Judge's decision, file exceptions, hold an oral argument, and issue a final decision within the five months' suspension period.

Several years may pass between the date the utility proposes a rate increase and the date when the rate is finally allowed by the FERC, particularly if one of the parties requests a court review of the Commission's decision. This delay is a matter of great concern to pipelines. During this period, a company may be collecting money that the pipeline may have to refund in part or entirely with interest. Likewise, the distribution utility does not know whether or not the rate it is paying is a true expense. This is an important consideration in the determination of the distribution company's retail rates.

This lag can be reduced by a settlement conference. Under this procedure, the pipeline, its distribution customers, and other intervenors (e.g., state regulatory commissions, representatives of the FERC, and others) participate in an informal conference to reach a compromise on the various issues. If a settlement is reached, it is submitted to the FERC for its approval. As a method of regulation, the settlement conference can expedite the resolution of a rate case in a way that avoids the expensive and time-consuming litigated rate proceeding, while meeting the statutory obligation of the Commission to determine just and reasonable rates.

THE COST OF SERVICE

The first step in the preparation of a pipeline rate case is the determination of the company's total cost of service. This is the sum of the

pipeline's expenses (including depreciation, depletion, and amortization), income, and other taxes, and a reasonable return on the utility's rate base for a given test period. The FERC regulations specify a test period consisting of the 12 consecutive months of the most recently available actual experience, adjusted for known and measurable changes in revenues and costs that will occur within nine months of the end of the twelve months of actual experience. Deviations from the prescribed test period may be allowed if the company applies 30 days in advance of the filing. The last day of the 12 months of actual experience may be no more than four months prior to the filing date of the rate increase. Typically, the rate increase will become effective, subject to refund, after the routine five-month suspension on a date close to the last day of the test period.

Adjustments to actual experience may include the costs of facilities for which a permanent or temporary Certificate of Public Convenience and Necessity is outstanding, provided that such facilities will be in operation within the prescribed test period.[5] Supporting schedules must show the details of any adjustments. Any adjustment to actual experience must be reasonably definite and certain and should not be merely speculative. Items of a nonrecurring nature must be eliminated in the fixing of future rates. This does not preclude the replacement of the nonrecurring items with another item of a nonrecurring nature that the utility anticipates will be realized in the future.

The utility's return is a significant element of the cost of service. It is derived by multiplying the company's rate base by a rate of return. The NGA does not limit the FERC's determination of the rate base. The Commission considers the rate base to be the original cost of the company's plant that is "used and useful" in gas service, less the accumulated provision for depreciation, depletion, and amortization, and accumulated deferred income taxes, plus working capital. Because a utility must first obtain certificate authorization before expanding its facilities and the Commission has already determined the original cost of the property of most companies, the FERC has control over the components of a pipeline's rate base. Unlike many state regulatory agencies, the FERC has thus far refused to depart from its depreciated original cost theory of ratemaking.

[5] Frequently, the FERC approves requests for the inclusion of costs related to the uncertificated projects subject to a condition that if the facilities are not certificated or in-service by the end of the suspension period, the company would place in effect reduced rates which would reflect the elimination of those costs.

COST CLASSIFICATION AND ALLOCATION

After the total cost of service has been developed, a cost classification and allocation must be prepared as a step in establishing the regulated prices for the various utility services. If part of the company's business is not subject to FERC regulation,[6] this cost classification and allocation will determine the share of the total cost of service borne by the jurisdictional and nonjurisdictional classes of customers. Cost analyses also provide data that may be used as one consideration and as a point of reference in the design of rates for various classes of service or several zones varying in distance from the source of supply if multiple rate zones exist.

The term "cost allocation" has been used rather loosely in the gas industry to describe a *complete* cost study. Actually, the cost-allocation procedure is only one step in the long process of developing the proper prices for the various services. The cost analysis, used here to include cost allocation, proceeds from the initial step of (1) arranging the costs by functional groups to that of (2) cost classification, (3) cost allocation as between jurisdictional and nonjurisdictional business, and (4) cost allocation among jurisdictional services. Where applicable, cost allocation includes the apportionment of the jurisdictional cost of service among the various rate zones and the further allocation based on distances from the source of gas. The steps that comprise the cost classification and allocation process are designed to identify the nature, characteristics, and behavior of system costs and to identify the classes of service or customers that are deemed responsible for the incurrence of such system costs.

The FERC's Regulations require and its Uniform System of Accounts[7] provides that costs be segregated into functional groups. The major functional groups of a pipeline system's costs are gas procurement (purchased gas, production, and gathering), transmission, underground storage, distribution, customer, and general. A particular pipeline company may or may not incur costs associated with each of the above functional groups, but a breakdown is required because cost behavior may differ from various parts of a pipeline system and costs associated with one or several functional groups may have to be assigned in different proportions to various utility services.

[6] Under the Natural Gas Act, the FERC does not have the authority to regulate direct pipeline sales to ultimate users or the local distribution of natural gas.

[7] 18 Code of Federal Regulations 201, et seq.

After costs have been separated into major functional groups, a further classification typically follows within each function as to the "fixed" or "variable" nature of such costs. The distinction between "fixed" and "variable" cost is not peculiar to the pipeline industry but is fundamental in the analysis of the cost of any business enterprise. It is generally of greater importance in the utility field, however, in view of the relatively greater proportion that capital or fixed costs bear to total cost. The FERC generally recognizes the validity of such classification of costs and has defined the costs as follows:

> Fixed or constant costs are those which relate entirely or predominantly to the capital outlay necessary to provide the system capacity and also those operating expenses which do not vary materially with the quantity of gas transported through the pipeline system. Variable costs, on the other hand, are those which vary with the volumes of gas transported through the transmission system.[8]

Although most fixed costs generally are related to the capital outlay associated with the capacity of the pipeline, included as well are those operating expenses that do not vary materially with variations in the quantity of gas transported through the pipeline system. There are also many operating costs generally associated with the capacity of the system that are relatively fixed, such as the operation and maintenance of structures and mains and compression station labor. While many administrative and general expenses are not directly associated with system capacity, such expenses nevertheless do not vary materially with throughput and are typically classified as fixed costs.

Another cost element that may include a substantial amount of fixed cost is the cost of purchased gas. When a pipeline purchases gas from another pipeline under a demand-commodity rate, the demand charge portion of the total charges is classified as a fixed cost. The classification of the functional elements of cost as to their fixed and variable nature is guided by engineering and economic facts. It is not affected by the particular functional group nor by any ratemaking considerations.

After the costs are classified, the next step is allocation. This operation should distribute equitably the cost of service between jurisdictional and nonjurisdictional business. For pipelines having part of their business not subject to FERC regulation, the allocation method chosen is usually a point of controversy. An arbitrary assignment of excessive costs to either the jurisdictional or the nonjurisdictional segment of a company's business would have a significant financial impact on both the pipeline and its customers. Moreover, this would set an improper level of costs for both the regulated and nonregulated segments.

[8] Northern Natural Gas Company v. FPC, 206 F.2d 690, 1 PUR 3d 310 (1953).

The FERC costing procedures focus on a "cost of service" allocation, not an allocation of property or property costs. This principle of cost allocation as opposed to physical property segregation was approved by the FPC in one of its earliest major rate cases.[9] Some or all of a pipeline's fixed costs could be assigned to the commodity component and, thereby, would be allocated between jurisdictional and nonjurisdictional business on the basis of annual deliveries.[10] This is a controversial aspect of pipeline costing and ratemaking. Nevertheless, two cost-allocation procedures, the "peak responsibility" method and the "volumetric" method, represent attempts to address this controversial step.

Under the peak-responsibility method, 100 percent of the fixed costs are considered demand- or capacity-related costs. These fixed costs would be allocated among classes of service in proportion to the demands of the classes during a one- or three-day peak. In contrast, a purely volumetric method would assign 100 percent of the fixed costs to the commodity component and subsequently would be assigned to classes of service on the basis of annual deliveries to each class.

The nonjurisdictional segment of a pipeline's business generally will carry proportionately more of the system's cost of service if an annual (volumetric) basis is used rather than the peak-period method. The heavier incidence of interruptible, high-load-factor, and nonweather sensitive demands of the direct (nonjurisdictional) customers compared to the loads of the jurisdictional customers accounts for this shifting of cost burdens. Consequently, the cost of service and the revenue requirement attributable to a pipeline's jurisdictional business can vary materially depending on the proportion of fixed costs assigned to the commodity component and, therefore, allocated by annual deliveries.

[9] Colorado Interstate Gas Co., Docket No. G-124, et. al., 3 FPC 32 (1942); affirmed Colorado Interstate Gas Co. v. FPC, 324 US 581 (1945).

[10] Although an allocation is generally required, some pipelines with immaterial amounts of nonjurisdicational business are permitted to credit nonjurisdictional revenues to the total cost of service to determine the jurisdictional cost of service. For such pipelines, as well as those with nonjurisdictional business, this particular aspect of the classification and allocation procedure is generally not an issue except as it may have impact on the final rate designs.

The earliest cases before the FPC were resolved by use of a cost-allocation method like the pure peak-responsibility approach. A movement away from this policy, however, began with the landmark Atlantic Seaboard decision.[11] Under the Seaboard method, 50 percent of the fixed costs are assigned to the commodity component and, together with all of the variable costs, allocated by annual sales factors.[12] The other 50 percent of the fixed costs remains as demand-related costs and is allocated by peak factors. Under Seaboard, the FPC gave equal weight to the peak and annual service functions as the reason for cost incurrence.[13] As a practical matter, the splitting of fixed transmission costs between demand and commodity components ensured that some fixed costs were apportioned to both off-peak and peak-period users.

For more than 20 years, the Atlantic Seaboard formula served as the predominant cost classification and allocation methodology. In 1973, the FPC began to give increased consideration to classification methods that assigned additional fixed costs to the commodity component for both cost allocation and rate design. The rationale for this shift was the existence of excess peak-day pipeline capacity. Greater cost emphasis was placed on annual system service. In addition, the FPC wanted to increase the commodity cost of gas to industrial users via cost classification and allocation methods. One such formula, the "United"[14] method, assigns 75 percent of the fixed costs to the commodity component and only 25 percent on the demand side. Arithmetically, this is midway between the Seaboard and volumetric methods. United, compared to Seaboard, reduces the jurisdictional cost of service and revenue requirements.

[11] 11 FPC 43 (1952).

[12] Although an appreciable part of purchased gas and production costs are indeed fixed, all such supply costs, with the exception of demand charges associated with purchases from pipelines, are generally classified as variable and/or are assigned wholly to the commodity component. See Northern Natural Gas Co., Docket No. G-1382 et. al. 11 FPC 123 (1952); affirmed State Corporation Commission of Kansas vs. FPC, 206 F.2d 690 (8th Cir. 1953).

[13] We known that both functions (demand and volume) are very significant. This is not a case where one form of joint use greatly predominates. It is our opinion that these significant cost factors should be weighted equally, that is to say, 50 percent should be assigned to demand and 50 percent to commodity." (11 FPC 56).

[14] United Gas Pipe Line Co., Docket No. RP72-75, FPC Opinion No. 671: 50 FPC 1348 (1973); affirmed Consolidated Gas Supply Corporation vs. FPC 520 F.2nd 1176 (D.C. Cir., 1975).

The most recent innovation by the FERC is its "modified fixed-variable method." After 1978, the rapid increase in costs made gas more expensive than alternate fuels in industrial markets. The modified fixed-variable scheme is a way of making gas competitive via rate design. This approach assigns all of the fixed costs to the demand component, except for return on equity and related income taxes. These are assigned to the commodity component. The shift from United to modified fixed variable for classification, allocation, and rate design moves cost responsibility between classes of customers dramatically. One way to soften this effect is to use Seaboard for classification and allocation but then to use modified fixed variable for rate design.

The various cost classification formulas are illustrated in Table 12-1. As previously discussed, Seaboard balances the volumetric and peak responsibility methods. United skews costs toward the volumetric classification and allocation method. The impact of these alternatives on the jurisdictional cost of service and revenue requirements is highlighted by the "boxes" shown in Line 11 of Table 12-1. In brief, the choice of cost-of-service method can influence the relative cost burdens of various customer groups.

The allocation factors are the same regardless of the particular cost-classification method. In other words, demand-related costs would be allocated by peak-day or peak-period demands while commodity costs would be allocated by annual deliveries. The Atlantic Seaboard decision, which established the principles of classification of costs, also set forth the principles for deriving the factors for allocating the demand and commodity costs. The demand costs are allocated in proportion to the average of the class (jurisdictional and nonjurisdictional) coincidental demands during a three-day continuous peak period on the pipeline system. The commodity costs are allocated in proportion to the applicable annual volumes. Annual volume factors have been accepted for the allocation of commodity costs. Schemes other than system peak-period factors have been suggested for the allocation of the demand costs. These include a single peak day, contract demand, firm service peak day, and others. The three-day peak factor has been used almost universally by the FERC. The three-day factor was not changed by the United decision or in the modified fixed-variable settlements.

Another frequently contested feature of a pipeline's costing and ratemaking presentation is the allocation of the jurisdictional cost of service among rate zones. On this point, the FPC noted that:

TABLE 12-1
Impact of Various Cost Classification Methods on Jurisdictional Cost of Service and Revenue Requirements

Line No.	Functionalized Cost	Total	Peak Responsibility Demand	Peak Responsibility Commodity	Peak Responsibility Total	Modified Fixed Variable Demand	Modified Fixed Variable Commodity	Modified Fixed Variable Total	Atlantic Seaboard Demand	Atlantic Seaboard Commodity	Atlantic Seaboard Total	United Demand	United Commodity	United Total	Volumetric Demand	Volumetric Commodity	Volumetric Total
1	Production	$ 1,000	$1,000	$1,000	$ 1,000	$1,000	$1,000	$ 1,000	$1,000	$1,000	$ 1,000	$1,000	$1,000	$ 1,000		$ 1,000	$ 1,000
2	Purchased Gas-Demand	1,000			1,000			1,000			1,000			1,000		1,000	1,000
3	Purchased Gas-Commodity	1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000
4	Transmission	700	700		700	700		700	700		700	700		700	700		700
5	O&M-Variable	1,000			1,000			1,000			1,000			1,000			1,000
6	O&M-Fixed	1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000
7	Depreciation	300	300		300	300		300	300		300	300		300	300		300
8	Other Taxes	1,000	1,000		1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000
9	Income Taxes	1,000	1,000		1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000
10	Return	1,000	1,000		1,000		1,000	1,000		1,000	1,000		1,000	1,000		1,000	1,000
11	Allocation of Total Cost of Service to Classes of Customers	$10,000	$5,300	$4,700	$10,000	$3,900	$4,100	$10,000	$3,150	$6,850	$10,000	$2,075	$7,925	$10,000		$10,000	$10,000
12	Jurisdictional Cost of Service		$4,770	$3,995	$8,765	$2,510	$5,185	$7,695	$2,215	$5,821	$8,037	$1,867	$6,736	$8,603	$8,500		$8,500
13	Nonjurisdictional Cost of Service		530	705	1,235	390	915	1,305	315	1,029	1,343	208	1,189	1,397		1,500	1,500
14	Total Cost of Service		$5,300	$4,700	$10,000	$2,900	$6,100	$10,000	$2,530	$6,850	$10,000	$2,075	$7,925	$10,000		$10,000	$10,000

Derivation of Allocation Factors

	Peak Period Service Mcf	Peak Period Service Allocation Factor	Annual Service Mcmcf	Annual Service Allocation Factor
Jurisdictional	20,000	67%	1,000,000	81%
Nonjurisdictional	3,000	10%	230,000	19%
Total	23,000	100%	[illegible]	

> In theory, the ideal, nondiscriminatory, and nonpreferential rate structure would be one designed to assess each point of sale and delivery with the total of the various cost components incurred in the rendering of service to each point. But any attempt to arrive at such perfection would be not only delusory, but also impractical and infeasible from both the management and regulatory point of view.[15]

A pipeline uses rate zones to recognize the variation in its costs as the distance from its sources of supply increases and its transportation costs rise. Determining the number of zones is a particular problem. The FPC explained that:

> We believe that zones should include as large an area of service as may be consistent with equitable treatment to all customers.[16]

No general rule for establishing zones can be stated. In many cases, zone boundaries are arbitrarily established at a compressor station or at a state or county line. Factors that may be considered in establishing zones are: the distance of required transmission, load distribution, volume of gas sales, diversity of sales, load factor, and the history of company operations.

In some instances, the construction of a pipeline would not have been justified economically except for the existence of one or several specific markets. A zoning procedure that has an adverse impact on these markets to the advantage of other smaller markets located closer to the source of supply might be inappropriate. In such circumstances, uniform systemwide rates might apply (i.e., the rate structure is not zoned).

If desirable and if their limits have been set, the allocation of jurisdictional cost of service to such zones is the next order of business. Numerous methods have been used in an attempt to recognize mileage and, in some instances, pipe size. One frequently used method is the Mcf-mile. This approach recognizes that costs vary in proportion to the distance that gas is moved. Under this approach, an analyst calculates the weighted average transmission miles to move purchased and produced gas from the various sources of supply to a common point on the system, usually the last input point. Next, the number of transmission miles from that common point to each sales delivery point is computed. Thus, the total miles of haul consists of two parts:

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[15] Northern Natural Gas Company, Docket No. G-2217, Opinion No. 281; 14 FPC 11 (1955); affirmed, Interstate Power Company vs. FPC, 236 F.2d 372 (1956).

[16] Northern Natural Gas Company, 14 FPC 11 (1955)

the weighted average distance to the common point (a constant factor) and the distance from the common point to the point of delivery.

The analyst multiplies the total haul distance to each delivery point by the deliveries at such point during the peak period to obtain "demand miles." Similarly, commodity miles are calculated by multiplying the mileage to each delivery point by the annual deliveries to that point during the test period. These data are grouped by zones and used to allocate transmission costs among zones. A unit cost of service per Mcf-mile is obtained by dividing the transmission cost of service classified between demand and commodity by the total system Mcf-demand miles and the total system Mcf-commodity miles, respectively. This unit cost can be multiplied by the Mcf-miles determined for each zone to produce a total transmission cost of service for each zone. Production costs, except for demand costs, are allocated to all sales in proportion to the volume of annual sales during the test period. Customer costs are assigned to zones according to the number of delivery points, sometimes weighted for the type and size of meter as well as the frequency of reading.

A second approach of zone allocation is the "transfer of cost," "zone-gate," or "zone-by-zone" method. Under this method, transmission costs occurring within a zone are charged in proportion to the volume of sales made within that zone and to the volume passing from that zone to the next downstream zone. The costs transferred to the second zone are added to the cost of service within that zone. These costs are distributed to the sales made within the second zone and the volume passing from that zone to the third zone. This procedure is continued until all of the transmission costs have been distributed.

With this zone-by-zone method, the analyst must segregate the facility and operating costs of each zone as if each were a separate, independent transmission entity. Production costs are allocated to sales in proportion to the volume of annual sales during the test period. This method, however, has been used in very few pipeline rate cases. Cost analysts object to the method because of its underlying assumption that each zone be treated as an individual operating entity unrelated to other segments of the system. This contradiction with actual operating conditions explains the limited applicability of the "transfer of cost" method.

In addition to the Mcf-mile or "transfer-of-cost" approaches, numerous refinements to and combinations of these methods have been used. For example, the historical zone revenue pattern of a pipeline could be used to apportion costs to zones.

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RATEMAKING

The process of cost classification and allocation is separate from the process of rate design. Cost analysis is used to determine revenue requirements from jurisdictional and nonjurisdictional segments of the pipeline. It also is used to design rate levels and schedules for different classes of service and zones. Certainly, all capacity costs so classified because of their behavior are not indiscriminately included in the demand element of the rate merely because they are "constant" or "fixed." The cost analysis, however, does provide information to be considered in establishing rate levels.

Once a pipeline's total revenue requirements have been determined, the level and form of rates for different classes of service can be fixed at the discretion of management but subject, of course, to regulatory review. Differences in value of service, increased use of facilities, an indicated reduced cost of service per unit, or other considerations may dictate a departure from the allocated cost of service.

Ratemaking should be flexible but kept within the limits fixed by overall revenue requirements. Moreover, ratemaking should not be cast into a rigid mold by an uncritical use of the results of any method of cost classification and allocation. In the Atlantic Seaboard case, the FPC recognized that classified and allocated costs are "not necessarily controlling in the fixing of the precise level of demand and commodity" components of rates, but rather, such unit costs would provide "in the absence of other mitigating circumstances, a reasonably accurate guide as to the appropriate level for the demand charge and the commodity charge."[17] Subsequently, the Commission permitted adjustments to Seaboard-derived costs to account for special market or competitive conditions (e.g., incentives for load factor improvement and the development of storage facilities).[18] In practice, the FPC made pragmatic adjustments in the process of rate design.[19] Historical rate levels, zone differentials, and other items are important elements in the rate design process. It is seldom feasible to make a direct translation of cost analysis results to a rate level.

[17] (11 FPC 62).

[18] Southern Natural Gas Company (29 FPC 323).

[19] Similiar approaches (e.g., the "tilting" of rate structures in the direction of the demand component) were taken by the Commission in Midwestern Gas Transmission (21 FPC 653), Natural Gas Pipeline Company of America (28 FPC 731), American Louisiana Pipe Line (29 FPC 932), United Gas Pipe Line (31 FPC 1180) and United Fuel Gas (31 FPC 1342).

PIPELINE RATES

In its design of pipeline rates, the company's objectives parallel those of a distribution utility. Rates must be established at levels to recover the total costs of rendering service. Such rates must be free from unreasonable discrimination and preference. Moreover, they must meet the test of distributor and regulatory agency acceptance.

Pipeline companies, like gas distributors, are in business to sell energy and must, therefore, watch the price relationships among various forms of energy. Thus, pipeline analysts must give constant attention to current and prospective market conditions to avoid distributor opposition, ultimate end-use customer defection, and public relations difficulties. With the cost of gas comprising most of the rate to the consumer, a close coordination on pricing is a primary concern of both the pipeline and the distribution companies it serves.

The gas supply shortages of the 1970s led, in part, to innovations in rate design as well as cost classification and allocation approaches. For example, part of the rationale for the United cost classification method was to derive high unit commodity costs. These were converted into high commodity rates to discourage industrial sales or at least encourage more efficient industrial uses of gas.

After 1978, and with the passage of the NGPA, gas prices increased as did production, and shortages became a surplus. During that period, gas became unmarketable to many industrial customers. More recently, innovations in rate design as well as in costing methods (e.g., the modified fixed-variable method) reflect attempts by pipelines to encourage industrial sales by lowering the commodity rate. Stripping fixed costs from the commodity rate gives distribution utilities some flexibility in designing their rates for industrial customers given the competition of alternative energy sources.

Such shifts in regulatory policy arguably are at odds with traditional costing and ratemaking precedents but reflect a pragmatic acceptance of marketplace realities. One departure from precedent links discrete supply sources and facilities with specific categories of end-use or classes of service.[20] Because the impact among utilities and classes of service of such ratemaking schemes will be significant, resolving these and other ratemaking issues will be controversial.

For example, pipelines usually sell firm gas to distributors under demand-commodity rates. For each of these two price components, a

[20] Although the current terminology is neither clear nor consistent, some of these approaches are broadly designed as "incremental pricing" or "end-use ratemaking."

straight-line rate is used. In a demand-commodity rate, the minimum monthly charge is the demand charge multiplied by the contract demand or a percentage of it. In addition, some pipelines have take-or-pay provisions on commodity (i.e., gas volumes) that may require payment for certain volumes of gas during a month or a year whether used or not. In the mid-1980s, take-or-pay provisions have been at the same time renegotiated, ignored, and respected by differing pipelines, depending, of course, on specific circumstances, particularly the increasingly competitive energy marketplace.

Some pipeline companies use a straight volumetric rate for firm service. This type of rate is used frequently for nonfirm service and for optional small-volume rate schedules to distributors whose services are not very extensive either in quantity or diversity.

In the past, pipelines have offered interruptible service to distributors under two types of schedules. One covers service sold to a distributor for general use above its firm requirements. The other, not very frequently used, is for service to specific large industrial customers of the distributor.

A "summer-winter" rate is also used by pipelines but infrequently. Base-load gas is priced at a low level. A higher price is charged for gas taken in excess of base loads or average daily deliveries as established during the summer period. A summer-winter rate can be designed to have an overall impact roughly comparable to that of a demand-commodity rate. The demand charge equivalent is collected only during the winter months rather than throughout the year. A pipeline, however, could lose some revenue stability by not recovering its fixed costs through a demand charge.

Rates for transportation service are frequently found in the tariffs of large pipeline companies. Various transportation services may be available to distributors, to other pipelines, or to direct industrial customers. Transportation rates are designed to recover the cost of rendering that service. Such rates may be one-part (volumetric) or two-part (demand-commodity).

Pipelines sometimes make sales or provide transportation and other services to affiliates or others on a cost-of-service rate schedule.[21] In rare cases, this type of rate has been used in pricing gas sold to a distribution company.

Many pipeline companies make sales directly to industrial customers using rate forms similar to those of gas distribution companies.

[21] In a cost-of-service rate form, the monthly or annual charge is not based on a unit charge, but consists of the actual cost of service computed in a conventional manner.

These rates are beyond the jurisdiction of the FERC. The service obligations and other provisions reflect arm's length bargaining.

In addition to interruptible service, pipelines offer special services, including storage and emergency services. Under a "seller's option" storage service agreement, a distribution company with storage facilities will purchase for storage a certain annual quantity of gas at a rate lower than that for firm service. The pipeline decides when the gas is delivered. Thus, both parties can benefit from this kind of transaction.

In another type of storage service, the pipeline stores the gas *for* the distributor during the summer and makes deliveries during the winter heating season. The distributor buys the gas under its regular firm contract and requests the pipeline to place specified volumes into storage for the distributor's account. Rates for storage service may include a demand charge to reflect the carrying charges on the storage facilities, a small commodity charge or transmission charge, and an in-and-out charge for the costs incurred injecting and withdrawing the gas.

Another storage service is predicated on the use of liquefied natural gas. Under this approach, a pipeline can store large volumes of gas at critical points on its system for peak-day deliveries.[23] This procedure is economical because one cubic foot of LNG expands to approximately 600 cubic feet of gas in vapor form. For this type of service, rates are based on segregated costs.

In addition, pipelines may offer rates for emergency or auxiliary service to distribution companies. Although included in a number of tariffs, sales volumes under this type of class rate are generally small.

[23] Some distribution utilities have LNG storage of their own.

Chapter 16
The Rate Department

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RESPONSIBILITIES

In a gas utility, the rate department has broad responsibilities. To meet these challenges, rate people work with the staffs of most of the other departments of a gas company, particularly legal, accounting, marketing, gas supply, and engineering, as well as with representatives of the pipelines that supply the distribution company. In addition, the rate department people may call upon specialists or consultants from outside service organizations. This occurs particularly in smaller utilities where special assignments could create an unmanageable work load for the regular staff. A group of utilities may ask consultants to examine a subject of common interest to avoid duplication of effort and to draw on unique expertise.

The rate department's most important responsibility is to design rates that will yield adequate revenues from the sale of the company's gas services. To achieve this objective, a company's rate structure should:

- Recover the full cost of service, including a reasonable return on the company's investment, under present and foreseeable future load conditions
- Apportion the company's total costs equitably among the various classes of customers
- Reflect other ratemaking considerations (e.g., avoiding undue discrimination, respecting regulatory practices, recognizing historical continuity, etc.)
- Encourage an efficient use of gas service (e.g., pricing in a way that discourages the wasteful use of gas but allows stimulation of cost-justified usage)
- Provide flexibility to recognize the impact of competitive pressures

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To design appropriate rates, rate personnel must know the elements of cost involved in supplying each class of service, the amount of revenue required from each class, the trend of future costs, sales and revenues, and the effects of various alternative rate programs.

MONITORING CURRENT RATE AND ECONOMIC ISSUES

A rate department must keep the company's executives informed on current rate and economic matters, both local and nationally. This includes making studies of rate filings and proposals of other companies, and following significant rate and rulemaking proceedings of other regulatory commissions. Comparisons of other utilities' rates are made to keep abreast of costing and rate design methods for comparable service elsewhere. Such information can help a company answer its customers' inquiries. Differences among utilities in the conditions and costs of supplying service must be explained. In addition, participating in the activities of various industrial or trade associations can broaden the knowledge of rate department people.

THE RATE CASE

The rate manager is usually the company's technical contact with the regulatory commission on matters involving the utility's tariff. In a rate case, the manager is responsible for the preparation and presentation of information about rate form, rate level, and terms and conditions of service. Beyond those traditional responsibilities, the rate manager will also work with other department heads and with legal counsel in the conduct of the company's rate case. The rate manager is often a principal company witness.

RATE ADMINISTRATION

Rate administration is the application of the utility's rates. This involves preparing information and materials on rate matters for employees, investors, the public and the regulatory commission. Further, it includes ensuring that the rate structure is applied as intended. This is necessary to permit the utility to collect adequate revenues and to avoid discriminatory practices. To help guide the marketing, customer service, and customer accounting department staffs, rate people must interpret the details of rate provisions, availability, and applicability clauses. Other phases of rate administration include:

- Participating in the negotiations of major contracts for the supply and extension of service
- Preparing reports to regulatory commissions

- Answering customers' inquiries
- Calculating automatic rate adjustments
- Implementing and interpreting curtailment plans

FUNCTIONS

The principal functions of a rate department include:

- Load studies
- Cost of service studies
- Analysis of the effects of changes in rates on revenues
- Research on rate design
- Research on pricing and regulation
- Impact studies of local and national economic trends
- Collection and maintenance of basic statistics on billing data
- Preparation and presentation of rate cases
- Preparation of data for cases before state regulatory commis sions and the Federal Energy Regulatory Commission
- Preparation of revenue, sales, gas supply and curtailmen forecasts
- Preparation of contracts.

Although many rate departments are concerned mainly with th types of issues described above, some gas utilities have combined rat activities with other related management services. For instance, th talents required for rate work also can be used for economic an market research. In practice, the dividing line between such activitie is blurred. Table 16–1 summarizes these major and ancillary duties

ORGANIZATION

In a typical gas company, the rate function has the status of a department. The rate department manager generally reports directly to a senior or executive vice president. According to a 1983 A.G.A. survey, the average rate department had 19 employees. Rarely are there as many as fifty employees and sometimes there are less than five. This wide variation may be attributed to five factors:

- The greater the amount of detail handled by functions within a rate department, the number of employees, of course, is greater.
- In rate departments, the analysis of gas usage across customers requires the compilation of extensive bill tabulations. In many companies, such studies are a by-product of the billing system. The bulk of this work is done either by a company's computer services department or by an outside agency. If located within the rate department, this analysis would add to personnel requirements. In some instances, these studies can be done by the

Chapter 17
The Rate Case

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IMPORTANCE OF A RATE CASE

Rate filings sustain the financial integrity of a regulated gas company. In addition, the rate-application process brings the utility's people into contact with regulators. Over time, the rate cases influence this relationship and vice versa. Each filing affects future cases through the procedures used, the facts established, and the decisions made. The company tries to obtain a timely decision, one that appropriately adjusts the utility's rates. Nevertheless, ineffective presentations on the issues or untimely filings by the company as well as regulatory lag can adversely affect the financial health of the utility. Because of the fundamental importance of a rate filing, each case should be prepared and presented under the assumption that it could go to a court on appeal.

To make an effective case before a regulatory body, a utility should assess that particular commission's posture on the relevant issues, the resources of the commission staff, and its predisposition on each issue. The company should appraise intervenors' positions as well. With so much at stake in a rate case, a poor reading of the regulatory climate could result in an ineffective effort to obtain rate relief.

PLANNING THE RATE CASE

After a company determines that it must file a rate case, a detailed plan for doing so should be prepared and submitted to top management for approval. The plan should describe the rationale for an increase or decrease in rates and identify the witness responsible for making that presentation, as well as other witnesses. The plan and the filing itself

will reflect two aspects of the real world. First, utility regulation receives great attention by news media. Second, commission decisions are politically sensitive. Because utility managers know this, the company's plan as well as the rate case will anticipate both factors. As a practical matter, the rate case will involve an extensive use of internal accounting data. Assembling this information can influence the timing of a rate case. Moreover, the need for specific data (e.g., income taxes, expenses, wages, etc.) places limitations on the accounting periods used.

The company can anticipate the issues in a particular rate case. Each potential issue should be delineated, including those proffered by the company and those identified by other parties. Each issue should be ranked by its importance to the company. Supporting material and testimony should be prepared and filed reflecting those priorities. On the rate-of-return issue, for example, a quarter of a percent could be worth several million dollars to the company while another issue (e.g., allowing institutional advertising as an operating expense) might be worth only a few hundred thousand dollars. Some *judgmental* ranking of issues not readily measurable in dollars should also be made. Given these rankings, the company can focus its efforts and properly allocate its resources in the preparation of the case to each issue.

If a utility enters a rate case without a strategy, company witnesses might be put on the defensive, which could be a disadvantage procedurally. For example, a utility might not anticipate that billing practices would be raised as an issue by intervenors. Forced into an extended exchange of viewpoints in the hearing, this could result in delays, particularly if the company is required to furnish supporting data, allow the intervenors time to analyze the data and then take more time to rebut the company position.

In the often heated discourse of a hearing, issues such as executive salaries, subsidiary investments, etc. can take up time. Debating such topics has little value compared to the loss in revenues if the decision is delayed. A well-defined strategy and a pretrial brief can help apportion time and effort such that substantive issues are addressed in a timely way.

In demonstrating the company's financial position and needs, a test period is used. In selecting one, a utility may have several options. When inflation is minimal, companies may prefer to use historical test periods. Moreover, because comprehensive year-end reports and data are desired, a calendar year is preferred. This makes it easy for commissions to perform audits quickly and with less burden on company personnel. Some utilities find it desirable to use the most recent 12-month period for which data are available. While preparing such information may be more complex, this approach retains the advantage

of using a historical period (i.e., the parties have a record of actual experience). In some cases, companies make *pro forma* adjustments to the historical test period data to reflect future conditions. This technique has been accepted by many regulators and intervenors. Such adjustments could include negotiated wage increases, announced property tax increases, contractually established future cost increases in purchased supplies, etc.

Regulatory lag can adversely affect earnings. To relieve this attrition, some companies use a test year that is part historical and part forecast (e.g., six months of data from actual operations and six months of projected data). This approach can complicate a rate case because forecasts require judgment, expertise and extensive supporting data. Moreover, the forecasting methodology *per se* must be reviewed, while the underlying judgmental assumptions about inflation, conservation, supply costs, weather, etc. invite challenges. These inevitably extend the hearing and could delay a rate decision.

As the use of the partial forecast test period spread, the idea of a totally forecast test period emerged. Because the problems of forecasting were already being encountered, a total forecast test period did not seem to present further complications, particularly if such an approach was acceptable to the commissioners. Today, some utilities use test periods of a future calendar year. But, because of the lead time to prepare exhibits and testimony, a future test period may require forecasts of 18 months or more. During inflationary periods, the use of a forecast test period helps a company achieve its authorized rate of return. In the mid 1980s, with inflation abated, this argument has lost some of its force.

If rate cases are frequent (as they were in the 1970s), the rate-related activities of a utility's various departments can be made routine and simplified. Nevertheless, as new issues develop or new evidentiary requirements arise, other departments or individuals may become involved in the preparation of the rate filing. In either case, making specific assignments for the preparation of a rate case is desirable. To use company people and resources efficiently, coordination is essential. Specifically, the use of conflicting data in prepared testimony or exhibits could compromise the company's witnesses.

The need for outside expert witnesses should be established as early as possible. This facilitates gathering information for the witness. For example, an expert witness on cost-of-service allocations must have a substantial background in the operations and policies of the company. For cases requiring extensive data and involving numerous issues and witnesses, schedules and flow charts are necessary.

APPLICATIONS FOR RATE INCREASES

A rate application could be a brief document that provides only cu sory information about the company's need for rate relief. Such limited filing is submitted just to establish a position on a commission calendar. More commonly, a utility will file a comprehensive docume setting forth in detail the company's position on major issues. Commi sions require that before the hearing, the company inform all cu tomers as well as public agencies of the proposed rate increase.

In some jurisdictions, the complete affirmative case of the com pany is submitted with the application. This includes written testi mony and exhibits (so called "canned testimony") plus supporting dat or work sheets where necessary. Each regulatory agency has a writte filing procedure. Different approaches for submitting an applicatio may be acceptable.

LEGAL SETTING

Most rate cases are heard in a quasi-judicial proceeding. Commissioners, hearing examiners or administrative law judges conduct the proceedings, hear the testimony, and receive the evidence into the record. To present its position on any or all issues, each party can submit evidence. While a company may claim that it urgently needs a rate increase to remain financially healthy, the utility has the burden of proof to demonstrate that need and to present the rate changes necessary to obtain relief. An intervenor with an opposing viewpoint or different approach toward establishing the level of need may also submit an affirmative case. That party would also bear a burden of proof.

Rate hearings are conducted in a manner similar to a judicial proceeding (e.g., the rules of evidence are followed). Often, individual customers or inexperienced persons representing small groups intervene in rate cases. Thus, there is some latitude in procedures if these parties appear without legal counsel. Also in contrast to strict judicial procedure, hearsay testimony from expert witnesses may be admitted. Nevertheless, rate proceedings are adversarial in character (e.g., the direct testimony of a witness is followed by cross examination). Because of the technical nature of much of the testimony and exhibits, there is more latitude in cross examination than is allowed in a judicial hearing.

HEARING PROCEDURE

A hearing, for example, could start with routine procedural matters, continue with opening statements (if desired) by all participants, and proceed with the submission of the direct case of the company followed by an adjournment. The cross examination of company witnesses would come next. The direct case of any intervenor and the commission staff and the cross examination of the witnesses of these parties would follow. If rebuttal were necessary, it would come next. After the cross examination of the rebuttal is completed, the hearing is closed and a briefing schedule established. During the hearing, intervenors may obtain delays (over the objection of the company) by citing due process to allow the intervenors reasonable time and opportunity to challenge or rebut the company's evidence.

The hearing officer may allow the filing of legal briefs and, subsequently, reply briefs. This can prolong the case. When briefs are in, the case is ready for decision by the commission. In some jurisdictions, the hearing officer writes the decision or order and submits it to the commission and the parties. Each party can file exceptions to the examiner's decision.

EXHIBITS AND TESTIMONY

Witnesses submit evidence through testimony and exhibits that become part of the written record of the case. Later, under cross examination, a witness may shorten or elaborate on an explanation. A witness should be conscious of making a record. This will be read later or, perhaps, used as evidence in a court case if the commission's decision is appealed. A witness may be tempted to respond quickly to a question and have a limited exchange of words with the cross-examiner. When these exchanges are later read from the transcript, the inflection, volume and emphasis of the expert are difficult to judge. A pause to think of an answer does not appear in a transcipt but may result in a more effective response under cross examination. Because the rules of evidence are followed, witnesses should be told by legal counsel which comments, exhibits, or data might be ruled as irrelevant or hearsay and not allowed as evidence.

Exhibits can be invaluable instruments for presenting evidence or they can detract from the testimony. In some jurisdictions, hearing procedures may prevent a witness from repeating in testimony the data presented in exhibits unless needed for clarification. An exhibit should be able to stand alone. Thus, a complex exhibit may have less impact than a simple presentation of data with its logical conclusions

readily apparent. Simple graphs can complement testimony and influence a commission's decision. Conversely, if technical exhibits are numerous and detailed, they may receive cursory examination during the decision-making process. Thus, judgment must be exercised in using exhibits. Some might be included for clarity or impact while others might be needed to make an adequate evidentiary record upon which an informed decision can legally be made.

The testimony of outside experts receives mixed response. Some commissions give considerable weight to the opinions of the experts. Other regulators view consultants as mercenaries who say what they are paid to say. The credibility of expert witnesses and the respect they might command from a commission should be evaluated before using consultants in a hearing.

THE COMPANY'S DIRECT CASE

There are many ways to present the utility's affirmative case. Some companies use several witnesses, each an expert in a specific area, while a few utilities may use one executive to address all issues. Most companies choose a middleground. Relying on one person to cover all issues may reduce the extent of cross examination, but that witness could be exposed to cross examination on ancillary topics as well as rather remote issues. Nevertheless, a well informed company officer can shorten the process. That witness, of course, must be able to deal with cross examination and not succumb to challenges of his or her expertise. Alternatively, the use of numerous witnesses who are experts in specific areas usually can meet challenges on judgment and expertise.

The presentation of the company's evidence follows a logical sequence. In an introductory statement, legal counsel will indicate how the case will be presented, who will testify, and the thrust of the testimony of each witness. The testimony must establish the need for a rate increase. If the case deals only with rate design, the initial presentation might indicate that no increased return on investment would result from the proposed rate changes. More often, both rate levels and rate design are at issue.

A case might begin with a financial witness describing the company's capitalization and the utility's cost of capital (i.e., cost of debt and equity). These are key issues and require considerable expertise, particularly about the rate of return on equity capital and, recently,

the appropriate capital structure of the company.[1] The expert must use facts and figures to establish the level of return necessary to assure confidence in the financial integrity of the company, to maintain its credit, and to attract capital (e.g., a rate of return comparable to that earned by businesses with similar risks). The evidence presented may include comparisons with other utilities, industrial companies, groups of companies, and groups of utilities. In addition, historical financial data may be presented along with evidence of the company's current relative financial status. Such comparisons attempt to demonstrate the need for the requested rate increase.

Establishing the cost of debt capital is straightforward unless there is a future test period. A witness can compare bond ratings for various utilities and industrial companies to show the relative position of the company in the bond market. A utility's capitalization is a more complicated issue (i.e., most utilities have increased the portion of equity in their capital structure). Given the capital structure and the costs of equity and debt, a witness can derive the rate of return on rate base. In their decisions, most commissions usually make an explicit finding that establishes the rate of return allowed on rate base.

The rate base (i.e., the net value of the utility's investment) is the earning asset that realizes a fair and reasonable rate of return. Each regulatory body has a preferred method for calculating the rate base (i.e., plant investment at original cost,[2] plus working capital and inventories, less accumulated depreciation, depletion, amortization, reserves for deferred taxes, and contributions). Some jurisdictions allow all or part of the utility's investment in construction work in progress (CWIP) to be included in rate base. Other commissions use the concept of an allowance for funds used during construction (AFUDC).

Some witnesses show historic trends of rate base to demonstrate growth rates, to support a forecast period, or to offer arguments for a year-end rate base. Using a year-end rate base may offset the attrition of earnings caused by inflation. Such a rate base may be justified if it is close to the date when the new rates will be implemented. After the rate base and a rate of return are established, a calculation of total return to be included in the revenue requirement is made.

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[1] There is an extensive body of technical literature and legal precedent on the issue of rate of return. See for example, Bluefield (262 U.S.679), Hope (320 U.S.591) and Permian Basin (390 U.S.747).

[2] Some states use fair value for rate base measurement. In those jurisdictions, the allowed rate of return is usually lower but yields virtually an equivalent return on equity as compared to the original cost method. This is sometimes referred to as "paying lip service to fair value."

Company witnesses present evidence on operating costs. For a historical test period, such costs are easily established and simple to present (e.g., an income statement). A combination utility must show revenues, expenses, and allocated general expenses for the gas operations of the company as distinct from the financial data for electric operations. A commission and intervenors may question the company's inclusion of certain items in operating expenses (e.g., contributions, advertising, taxes, salaries, etc.). A utility should avoid pursuing minor issues if the costs of any resulting delay in the case exceed the value gained from a successful effort on those issues.

Together, the company's annual capital cost and operational costs constitute the utility's total revenue requirement. This is also called the cost of service (i.e., the total cost borne by ratepayers to receive service). In some cases, a utility may develop through testimony and exhibits only the increase in the cost of service (i.e., additional revenue requirements). A company may use this approach if the utility is not seeking an increase in its rate of return but only a "make-whole" or "offset" rate increase. The company asks for increased revenues to offset exactly a specific increase in expense, thus making the compai whole but not changing the rate of return the utility would earn.

JURISDICTIONAL SEPARATION

Many utilities must make some separation of costs between variou jurisdictions (i.e., among states, FERC, or subsidiary utilities). Th simplest separation would involve recovering a percentage of the tota revenue requirement from each jurisdiction based on sales in eac jurisdiction. More typically, some separation of the utility's in vestments and costs is made to establish a revenue requirement fo each jurisdiction.

Complications can arise if the methodology for establishing revenue requirements is different between jurisdictions. Some of the cost of service may "fall in the crack" (i.e., the sum of the revenue re quirements from each jurisdiction may be less than the company's tota revenue requirement). Nonutility subsidiary operations can cause fur ther problems. In some jurisdictions, the capital structure of the nonutility operation may be deemed different from that of the utility as a whole.

After a utility demonstrates its required overall revenue increase, the company must then explain the share each class of service must contribute to recovering the increase. Some commissions require a so-called "fully allocated" cost-of-service study to justify the proposed rate changes. Frequently, each party to a case will argue that other

customer classes should carry a greater share of the cost increases. Cost-of-service studies can indicate inequities or subsidies between classes.

Marginal cost studies focus on incremental unit costs. When multiplied by sales quantities, revenues for each class of service can be calculated. Marginal costs can be measured for different types of service (e.g., firm, interruptible, seasonal, etc.).

Regulators recognize that judgment is needed to design rates that recognize various considerations. Hence, witnesses often present testimony and exhibits that quantify impacts by class of service. Where value of service considerations are recognized, data showing the relative cost of gas versus other commodities and income are often useful.

In the past, industrial intervenors maintained a low profile during the revenue requirement phase of a rate case but became active when the increased rate burden was being apportioned among the classes of service. To make rate increases as innocuous as possible, some proposals raise rates by a fixed percentage for all classes. Other rate increases call for a uniform increase per unit of energy for all classes. In some cases, the rate level may be the only issue because a company may not want to risk a long delay over rate design issues that might hold up the increase in revenue requirements.

Redesigning rates is an opportunity to change the rules and regulations that govern service. Caution must be exercised, however, to preclude the rule changes from becoming issues that cause delay. Informal discussions with a commission's staff may reveal the best course of action. If a utility proposes a rule change (e.g., the prohibition of master metering), intervenors may become active and delays could be substantial. To avoid this, a utility can ask that the rule changes be separated from the rate case.

Because adjustment clauses can be a very significant revenue item, careful planning is necessary if changes are contemplated. The best method for changing may be a simple exhibit showing that the company is not overcollecting through the adjustment procedure. Intervenors attack adjustment clauses claiming that they guarantee the utility a rate of return and result in ratemaking without a hearing.

CROSS EXAMINATION AND REBUTTAL

During a rate-case hearing, witnesses must be available for cross examination by other parties. Cross examination usually attempts:

- To compromise the argument or results of

- To discredit the witness as an expert qualified to make judgments in a particular area
- To make a case contrary to that of the company by having the witness testify to certain facts, figures, and judgments which would be used by the intervenor

After cross examination, witnesses and their attorneys may decide that "redirect" is needed on certain points covered during cross. In addition, new testimony may be submitted through rebuttal evidence. This is presented in a manner similar to direct evidence. Rebuttal testimony is limited to issues raised in the direct case of the other party or during cross examination. Rebuttal may be followed by surrebuttal.

INTERVENORS

Rate cases typically involve other parties—the intervenors—besides the utility and the commission. For example, the staff of the commission may make a major showing as an alternative to the approach presented by the utility. Commissioners may place considerable weight on staff testimony because it may reflect the commissioners' own thinking. In preparing its case, the staff relies on the utility to furnish data. Here, the company should provide adequate and accurate data to the staff to earn its confidence. Loss of credibility with the staff can be damaging. Care should be exercised, however, in communicating with the staff during the case because other intervenors may challenge any *ex parte* activities. Actions that might compromise the staff's integrity could impair the company's efforts to obtain a timely decision. Nevertheless, *between* rate cases, communication with staff members is desirable because they are influenced by activities in other states or jurisdictions. Knowing the staff's position on a concept or anticipating a change in their thinking is invaluable in planning and presenting future testimony.

Industrial intervenors can be unpredictable and, potentially, difficult. Frequently such intervenors have the financial resources to bring in expert witnesses and to retain experienced legal counsel. Utilities may find it desirable to communicate with potential industrial intervenors if only to explain the company's position and possibly to mitigate opposition in the hearing.

Special interest groups have actively and effectively participated in rate cases. These include environmentalists, welfare activists, local government, and consumer advocates. Individuals can intervene and could complicate a case. A utility should not underestimate the ability and tenacity of special interest groups.

ORDERS AND DECISIONS

Following a rate case, the final decision or order may be delayed if the commission must struggle with complex evidence or intractable issues. In such instances, the commission may ask its staff to digest the testimony and exhibits. The person asked to explain a particular issue may have testified on that issue in the case (perhaps contrary to the position of the company). A company can help commissioners make a timely decision by presenting testimony and exhibits clearly and by writing briefs succinctly. In some jurisdictions, a commission will decide its position on each issue and request its staff to draft an order reflecting those positions.

Knowledgeable staff members can draft orders that specify rates, rules, and regulations in a way that makes prompt implementation of the new rates possible. This can obviate modifications of the commission's original order. This process can be facilitated by appraising the commission staff of implementation difficulties or peculiarities of the company's operations.

Commission rate orders usually link the revenues authorized in a case to judgment rather than to a specific formula. Some decisions based on a formula have been successfully challenged by showing that the formula was inappropriate. In contrast, the use of informed judgment is difficult to challenge. A party of standing in a case can appeal a decision for rehearing by the commission. This step is usually a prerequisite to exercising the full remedy—i.e., making an appeal to the courts. This would follow a denial of the rehearing of an application or reaffirming an order following a rehearing. A successful appeal to a court can result in a commission's decision being remanded to the commission to address a specific issue. Some court decisions can reverse or change a commission order on a certain issue.

PUBLIC RELATIONS

Public relations are particularly important when a company is involved in a rate proceeding. Working closely with the rate and customer-services departments, the public information department may carry out a consistent, long-range program of publicity and advertising to explain the cost of providing utility service and the company's rates. Such a program can create a climate of public acceptance that should facilitate a broad understanding of a particular rate application.

In planning for the rate filing, the utility's rate people must explain the essential purpose of the application to the public relations staff. A written summary of this purpose could be the basic document for the

preparation of all communications. Rate-related public relations activities should deal with:

- Preparing the rate story in a consistent manner while presenting management's point of view
- Communicating the story to various groups of people
- Scheduling the release of information
- Neutralizing incorrect information made public by other parties

Manipulating the timing of the rate filing and the release of information to the news media to minimize news play is not advisable. Such a tactic risks incurring an adverse reaction from the media. Rather the public information department should establish a reputation for honesty and forthrightness. In addition, employees should be informed through publications and meetings so they can answer the public's questions. Depending on the nature of the filing and the local attitude toward the company, other contacts should include:

- The utility commission and staff—by counsel or liaison
- City, county, and state officials—by personal contact
- Newspaper editors and broadcast news director—same as above
- Large industrial customers—by personal contact
- Employees—through district meetings, handbooks, and other publications
- Customers and the general public—by news releases for publication and broadcast simultaneously with the filing of the application, and by follow-up advertising
- Stockholders—by general letter

Prior to the scheduled public hearings on the rate application, the public information department may summarize the information from each exhibit for news media use. These summaries can help newspeople interpret the testimony of each company witness. Because of the lapse of time between the rate filing and the actual hearings, a second news release may be prepared for distribution at the opening of the hearings. The regulatory agency will announce the opening of hearings. A member of the utility's public relations staff should be assigned to the hearings to help newspeople obtain desired information on the spot.

FERC RATE CASE PECULIARITIES

Many utilities are under the jurisdiction of more than one commission. Frequently this includes the Federal Energy Regulatory Commission (FERC), which has procedures of its own that are prescriptive and unique. When a pipeline company files an application with the FERC for a rate increase, there are numerous statements and exhibits that

must be submitted. The company then has 15 days after the date of filing to submit proposed testimony.

Because of the rather protracted rate cases, many proposed rate changes become effective subject to refund prior to hearing if the filing is complete. FERC has statutory authority to suspend the collections of rate changes for a period of up to 5 months, after which the proposed rates become effective subject to refund should they be judged unjust and unreasonable in the final decision of the case. With this rather automatic implementation of rates, the test periods and cost studies can be based on established time intervals.

Under current procedures, the FERC staff will prepare "top sheets" (i.e., a brief position paper on the issues, based on a preliminary review of the application, filed data, and FERC records) approximately 90 days after suspension of the application. A settlement conference is usually convened about 10 days thereafter to attempt a reconciliation of differences and thereby shorten the duration of the case. Agreement may be reached on all issues or on some issues while others may be reserved for hearing.

In the past, settlement conferences were only incidental to the proceeding. Today, they are a primary and a dominant factor in obtaining a decision in a rate case. With few exceptions, all hearings and conferences are held at the FERC's Washington, D.C., offices. Other than the settlement conferences, oral presentations by technical witnesses are generally limited to cross examination in hearings.

The current settlement procedure is resulting in cases being completed within one year if settlement is reached and within two years if partial or nonsettlement is reached. Many companies appeal FERC decisions with the result that many of these cases may extend well beyond the one- or two-year period.

GLOSSARY OF UTILITY INDUSTRY TERMS

RESOURCE

An Encyclopedia of Utility Industry Terms

PG and E

Rate Advisory Program

January 1985

Allowance for Funds Used During Construction (AFUDC)

See also: **Construction Work in Progress (CWIP); Return on Common Equity; Used and Useful.**

The costs of financing the construction of new facilities before the facilities are included in rate base.

Construction of a new utility plant requires a great deal of time and an enormous amount of funds, or capital. The funds used for construction come from PG&E's sources of capital: short- and long-term debt, and preferred and common stock. These funds—which can range from millions of dollars for a small project, such as PG&E's Kerckhoff hydroelectric facility, to billions for a large one, such as the Diablo Canyon Nuclear Power Plant—are tied up for the construction project's duration. All funds used for construction projects are accumulated in an account known as Construction Work in Progress (CWIP).

The California Public Utilities Commission (CPUC) does not allow PG&E to include any CWIP in rate base, believing that the utility, not ratepayers, should bear the full burden of project construction costs until the project is operative. This is termed the "used and useful" standard. PG&E, therefore, earns no return on its investment until the plant is brought on-line and included in rate base.

When utilities are not allowed to earn a return to cover their financing costs during the construction period (because CWIP is not included in rate base), they are allowed to accumulate these costs for future recovery through AFUDC.

AFUDC includes both a debt component for borrowed funds (interest paid on bonds and short-term debt) and an equity component for common and preferred equity funds used to support a project's construction.

During the construction period, the utility reports the equity return portion of AFUDC below the operating income entry (below the line) on the income statement. The interest component for borrowed funds is shown as a reduction in interest expense, also below the line. The total of the equity and debt portions is added to the CWIP account on the balance sheet. Thus, the utility's income statement represents only the results of utility operations.

Cash inflows from both the debt and equity components of AFUDC do not occur until construction is completed and the plant is included in rate base. Even though it is reported as current income, AFUDC actually represents future cash flows.

Inclusion of AFUDC in the income statement increases net income, which in turn increases the return on common equity. However, AFUDC is not cash and cannot be used to pay interest expense or dividends. A company with an extensive construction program may be required to raise additional capital to meet its interest and dividend obligations. Such companies may have seemingly high net income, yet, in reality, may be experiencing severe cash-flow problems. Not surprisingly, if AFUDC is eliminated in the net income calculation, the return on common equity can drop quite significantly.

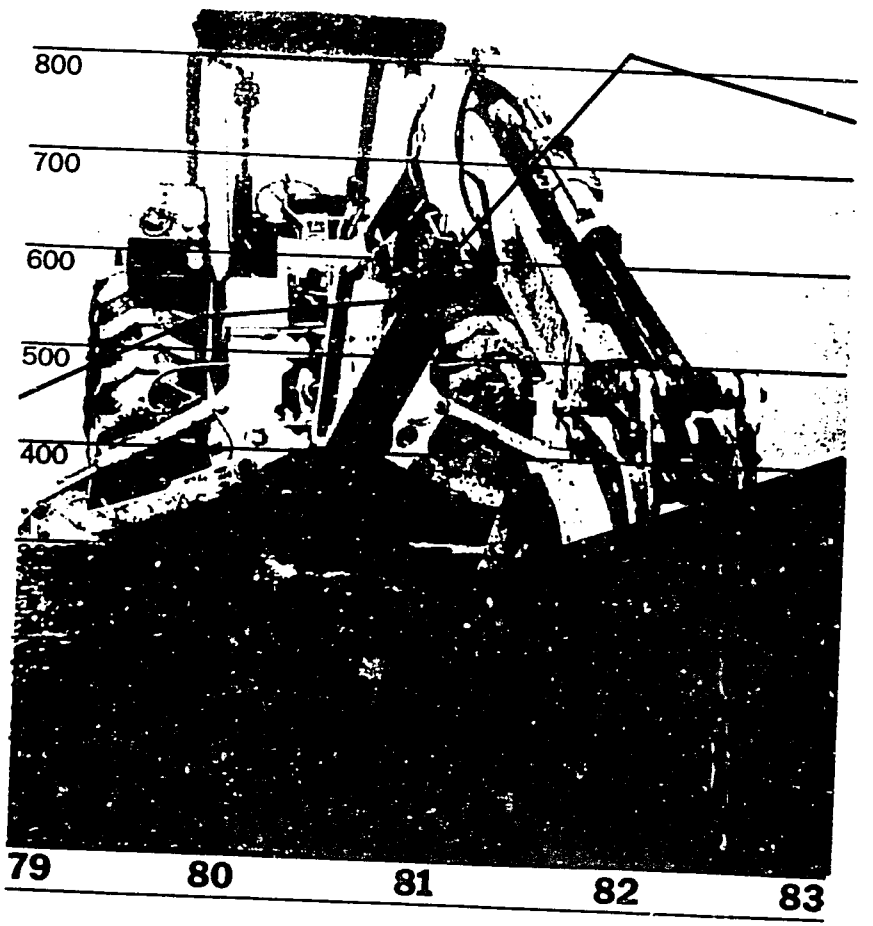
AFUDC is developed by calculating a rate, consisting of debt and equity components, and multiplying this rate by an applicable average CWIP amount. Although the Federal Energy Regulatory Commission Uniform System of Accounts for Public Utilities provides for an annual rate, the CPUC authorized PG&E to calculate a monthly rate. The rate components are weighted to determine the overall cost of capital and include the following:

- SHORT-TERM DEBT: a weighted average of the short-term debt and balancing account interest rates.
- LONG-TERM DEBT: the long-term debt embedded cost rate (including mortgage bonds issued by PG&E and Pacific Gas and Electric Finance Company N.V., and those issued for pollution control facilities).
- PREFERRED STOCK: the preferred stock embedded cost rate.
- COMMON EQUITY: the return on common equity authorized by the CPUC.

In the 1950's and 1960's, the ratio of AFUDC to net income was approximately 5 percent for the average electric utility. This was prior to the tremendous surges in inflation and construction costs and the extended construction periods required of projects like nuclear power plants. As costs soared, AFUDC changed from an insignificant accounting item to a large component of net income and a potential area of financial weakness. The ratio of AFUDC to net income now averages more that 50 percent, with a few utilities reporting all their net income from AFUDC.

RESOURCE

AFUDC Component of Net Income, 1979-1983



Total net income

AFUDC

As of December 31, 1983, PG&E's AFUDC was $430 million, or approximately 55 percent of net income.

Source: *PG&E Annual Report*, 1983, p. 22.

Utilities with large amounts of AFUDC tend to have lower bond ratings and higher capital costs, because financial analysts consider AFUDC to be low-quality income. The ratio of AFUDC to net income has therefore become a critical factor in evaluating the financial strength of a utility.

As of December 31, 1983, PG&E's AFUDC was $430 million, or approximately 55 percent of net income. While this represents a significant portion of net income, it is not unusual—PG&E had two large long-term construction projects nearing completion.

PG&E

Capital Structure

C

See also: **Capitalization Ratio; Cost of Capital; Long-Term Financing; Rate of Return.**

The composition of financing that meets a firm's investment needs.

The components of a capital structure are long-term debt (bonds), preferred stock, and stockholders' equity (common stock and reinvested earnings). By contrast, a firm's financial structure refers to the capital structure plus its current liabilities.

In establishing the optimal capital structure, the firm must examine the costs involved with each type of financing. Long-term debt, or bonds, carries with it periodic interest obligations to investors. Dividends must be paid annually to preferred stockholders. There is no required payment for common stockholders, yet a certain rate of return is expected or investors may not be attracted.

Considering these costs, as well as financial risk, investment requirements, and other factors, the firm seeks to establish a target

PG&E's capital structure is authorized by the CPUC in general rate case decisions.

PG&E's Adopted Rate of Return Test Year 1984, Attrition Year 1985

Component	*Capital Ratio (%)*		*Average Cost of Capital (%)*		*Weighted Cost (%)*
Average Year 1984					
Long-Term Debt	44.00	×	10.22[1]	=	4.50
Preferred Stock	13.75		9.44[1]		1.30
Common Stock Equity	42.25		15.75[2]		6.65
Total	**100.00%**				**12.45%[3]**
Average Year 1985					
Long-Term Debt	44.00	×	10.37[1]	=	4.56
Preferred Stock	13.75		9.57[1]		1.32
Common Stock Equity	42.25		15.75[2]		6.65
Total	**100.00%**				**12.53%[3]**

1. Assumes long-term debt cost of 12.5 percent and preferred stock cost of 12.25 percent in 1984 and 1985 and actual 1983 debt and preferred stock costs.

2. Authorized rate of return on common equity.

3. Authorized rate of return on rate base.

Source: *PG&E 1984 General Rate Case Decision*, p. 28h.

capital structure. The firm then uses this target structure as a goal for future financing.

Unique to public utilities within their capital structures is the relatively large amount of long-term debt. A utility has a more stable earnings base and is therefore more likely to earn sufficient funds to cover interest payments. Other industries must be more concerned with interest payments, for their annual earnings can fluctuate widely.

PG&E's capital structure is scrutinized by the California Public Utilities Commission (CPUC) during general rate case proceedings. Through this process, the CPUC staff and intervenors suggest alternatives to PG&E's proposed capital structure and rates of return on rate base and common equity.

Coincident Demand

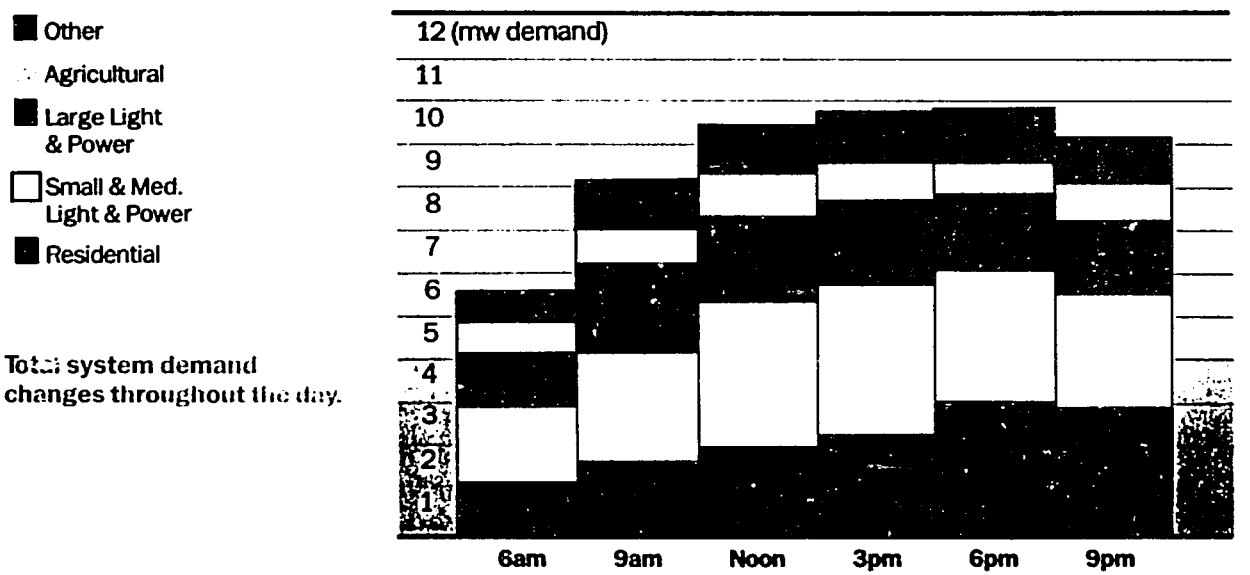
See also: **Coincidence Factor; Demand; Noncoincident Demand; Time-of-Use.**

A customer or class demand, in kilowatts or megawatts (mw), at the time of a utility's system peak demand. It is the demand that coincides with the system peak and is often used in cost allocation.

In a broader sense, coincident demand can be individual or class demands occurring in any specified demand interval. For example, industrial customers' demands at the time of the industrial class peak demand could also be considered coincident demands, even though they may not be coincident with the system peak.

In the accompanying illustration, the various customer groupings have the noted demands at three-hour time intervals from 6 A.M. to 9 P.M. The system peak demand is at 6 P.M., when the combined demand equals 9.8 mw. However, nonresidential classes do not experience maximum demand at the same time as the utility's peak load: small, medium, and large light and power all reach maximum demand at about 3 P.M. Only residential peak load is coincident with the system peak at about 6 P.M.

PG&E Coincident Demand



Total system demand changes throughout the day.

Cost of Service

C

See also: **Average Cost; Coincident Demand; Customer Classes; Marginal Cost; Noncoincident Demand; Rate Design; Value of Service.**

A method of using utility costs in rate design.

A cost-of-service study measures the utility's costs incurred in serving each customer class, including a reasonable return on investment. Utilities do not measure the exact cost of serving any one customer, or even a particular class of customers, but rather measure the cost relationships among various customer classes. These studies are an initial step in setting reasonable rates.

A cost-of-service study determines a utility's total costs for a specified period of time—generally one year. The first step in the study is to functionalize the costs; that is, to identify the equipment costs used in providing different services. Costs are functionalized into generation-, transmission-, and distribution-related costs. Further cost breakdowns may be made between the transmission, and primary and secondary distribution functions. Natural gas costs are broken into the following functional categories: production, transmission, underground storage, distribution, and general.

The second step is to classify the functionalized costs into categories that reflect their cost-incurrence. These categories are generally demand, energy or commodity, and customer costs:

- DEMAND COSTS: vary in proportion to the level of demand placed on the system, usually at the time of system peak. These costs include the majority of generation, transmission, and distribution plant investment, as well as the portion of the distribution system required to provide loads above a nominal level. Demand costs are closely related to the highest level of demand placed on the system, because the system must be able to accommodate that level, even if it is only for a relatively short period of time.

- ENERGY OR COMMODITY COSTS: generally vary with the number of kilowatt-hours (kwh) or therms produced and consist of costs for fuel burned, gas purchased, and part of the purchased power costs (some purchased power costs are fixed over a period of time).

- CUSTOMER COSTS: generally vary in proportion to the number

of customers being served and include the portion of the distribution system and related property required to establish basic service for a customer, as well as metering, accounting, and billing costs.

Once the costs have been functionalized and classified, they are then allocated to the customer classes. Demand-related costs may be assigned in many different ways. One approach is to allocate the demand costs only to those customer classes which contribute to the peak demand for which a facility is designed. Under this method, known as coincident-demand pricing, a customer class with only off-peak demand (noncoincident demand) would not be allocated any of the demand costs. Noncoincident demands can also be used to allocate demand costs. With this method, customer classes are allocated a portion of demand costs in relation to their individual peak demand, regardless of when their peak occurs in relation to the system peak.

Energy costs are a function of the number of kilowatt-hours or therms produced and can be allocated to the customer classes based on the kilowatt-hours or therms consumed by each class. Customer costs may be allocated to the customer classes based on the total demand and the number of customers in each class.

Cost of service is one of several approaches that can be used to design rates; others include marginal costs and value of service. Whether or not the cost-of-service study is used as the basis for setting rates, it is a very useful device for analyzing the costs incurred by a utility.

Customer Charge

C

See also: Customer Costs; Demand Charge; Energy Charge; Fixed Costs; Minimum Charge; Service Charge.

One component of a customer's bill, along with the demand charge and the energy charge. This charge recovers some of the fixed costs that are directly attributable to serving an individual customer.

These fixed costs are recovered through a flat charge per customer, regardless of the amount of energy used in a month. The customer charge does not include any costs for demand, kilowatt-hours, or therms consumed; these costs are collected by demand and energy charges.

Even if the customer uses no gas or electricity during the billing period, these customer costs must be recovered. The charge provides a price signal to the customer that there are costs associated with serving him, independent of his demand for or consumption of energy.

As of January 1, 1984, PG&E replaced customer charges with minimum bill provisions.

As of January 1, 1984, PG&E replaced customer charges with minimum bill provisions.

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 7787-E
Canceling Revised Cal. P.U.C. Sheet No. 7729-E

Schedule No. A-18B

INTERRUPTIBLE SERVICE — TIME METERED

APPLICABILITY

This schedule is applicable to three-phase alternating current service for customers with at least 500 kw of interruptible demand at standard voltages of 60,000 volts or higher except as may be provided in Special Condition 14 below. Service under this schedule is supplied if, in the Utility's sole judgment, there exists sufficient generation reserve and transmission margin.

TERRITORY

The entire territory served.

RATES

	Per Meter Per Month	
	Period A	Period B
Customer Charge:	$715.00	$715.00
Energy Charge:		
All kilowatt hours, per kwhr	$ .01298	$ .01298

Adjustments:

The above base rates are subject to possible adjustment for voltage and/or power factor. In addition, bills for service will include adjustments, as specified in Parts B, D and E of the Preliminary Statement, as follows:

	$ Per Kwhr		
	On Peak	Partial Peak	Off Peak
Period A			
Energy Cost Adjustment	$ .03830	$ .03630	$ .03430
Solar Financing Adjustment	.00002	.00002	.00002
Electric Revenue Adjustment	.00000	.00000	.00000
Total	$ .03832	$ .03632	$ .03432
Period B			
Energy Cost Adjustment	$ .03830	$ .03630	$ .03430
Solar Financing Adjustment	.00002	.00002	.00002
Electric Revenue Adjustment	.00000	.00000	.00000
Total	$ .03832	$ .03632	$ .03432

Customer C

See also: Agricul Commercial and Class; Cost of Se Resale Class; Re Class; Ultimate

- Residential
- Commercial[1]
- Industrial[2]
- Agricultural
- Resale
- Street Lighting

*Total includes mis and other accounts totaling $48,240,00

†Total includes mis accounts not show $5,469,000.

1. Includes railway departmental, med commercial.

2. Includes firm an accounts.

Source: *PG&E Fin Statistical Report,* 17, 20 & 21.

RESOURCE

C

For reporting purposes, these three classes are often grouped into commercial and industrial categories. Gas customers are grouped into residential, commercial-industrial, and resale categories.

The accompanying tables compare PG&E's customer classes in terms of 1983 sales, revenue, and number of customers.

Customer Costs

See also: Cost of Service; Customer Charge; Demand Charge; Energy Charge; Fixed Costs; Minimum Charge; Service Charge.

Costs relating to and varying with the number of customers. Customer costs are not related to the customer's demand or consumption but are fixed costs directly attributable to serving a customer.

Because these costs are relatively stable, they are often recovered through a flat monthly charge per customer or in a minimum bill. Even if the customer uses no gas or electricity during the billing period, there are costs associated with serving that customer. The customer's meter must still be read, the information processed, and a billing statement rendered. PG&E must also recover carrying charges and operating expenses associated with the secondary distribution system and the customer's meter.

PG&E

Depreciation

See also: Amortization; Flow-Through Accounting; Normalization Accounting; Taxes.

An accounting mechanism in which the cost of a fixed asset (such as a building or a piece of machinery) is allocated to the periods of the asset's useful life, or the periods in which services are received from it.

Depreciation is a recognized cost of doing business and is recorded as an operating expense on the company's income statement.

A utility's physical assets do not last indefinitely. Although there are some exceptions, such as land or natural gas reserves, most assets deteriorate over time. Equipment can physically break down from normal use; it also can become damaged, obsolete, or inadequate to perform its functions. Depreciation, in a sense, represents this decline in value.

There are several different methods of calculating the annual depreciation charge. The simplest approach is the straight-line method. An estimate of the net cost to retire the plant or equipment from service, the net salvage value, is deducted from its original cost. The result is then divided by the asset's estimated life. This amount is collected annually through rates as an above the line cost-of-service item. The straight-line method can be adjusted to allow for unanticipated changes in the asset's estimated useful life—such as regulatory or operating requirement changes. Annual collections for depreciation are accumulated in the Depreciation Reserve accounts, which are deducted from rate base.

Another approach to determining depreciation is accelerated depreciation, which is used primarily for income tax purposes. In this method, larger depreciation amounts are allocated in the early years when a plant is new rather than in later years, when the plant is presumably producing less efficiently. This method substantially reduces a utility's income taxes during an asset's early years.

There are other forms of depreciation, such as the sinking fund, sum-of-the-years digits, equal life groups, and unit-of-production methods, each with a specific set of calculations to arrive at different charges over the life of the asset.

RESOURCE

PG&E uses the straight-line remaining life method for its income statement and various other methods of accelerated depreciation for income tax purposes in accordance with state and federal tax laws. Since 1981, PG&E has been required by federal law for ratemaking purposes to make periodic allocations of the benefits resulting from accelerated tax depreciation for assets added after 1980.

PG&E

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Elasticity of Demand

See also: **Load Management; Time-of-Use.**

The ratio or degree to which consumers change their demand for products and services in response to a change in price.

The elasticity of demand ratio is determined by dividing the percentage change in the quantity purchased by the percentage change in the price of the product. Elastic demand exists when quantity changes by a larger percentage than price (elasticity ratio of greater than one). Inelastic demand is represented by a larger percentage change in price than in demand (elasticity ratio of less than one).

Until recently, utility services were thought to be relatively inelastic, since the products involved were essential to the public. Therefore, it was assumed that the public would consume roughly constant levels of electricity and gas, regardless of changes in price. However, the recent years of rising fuel prices have proved this theory wrong. As utility rates have increased to cover rising energy costs, people have significantly reduced their consumption and demand in response to those changes. For example, demand for utility services has become more elastic. Meanwhile, those services remain essential to the public's well-being and economic growth.

Utilities have turned to innovative load management programs and rate structures to take advantage of, and to further encourage, this elasticity of demand. Customers continue to use the products supplied by the utility, but their consumption increases when prices fall and decreases when prices rise. Load management programs and time-of-use rates encourage efficient energy use and minimize the effect of rising energy prices on the consumer.

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Embedded Cost

See also: **Marginal Cost; Rate Design; Revenue Requirement.**

An historical cost, or a cost that was incurred in the past.

The costs associated with financing and depreciating current plant are embedded costs, in that they have already been incurred and cannot be varied. The embedded cost of service includes the capital cost of existing capacity, including plants built years ago as well as the most recent capacity additions.

Embedded costs are associated with current capacity, while marginal costs consider only the cost of producing an additional unit of output. For instance, the capital costs of an existing plant are not relevant to a marginal cost study. However, these costs must be considered in setting a utility's revenue requirement. The consideration of different elements for determining marginal and embedded costs makes it clear that marginal cost-based rates can vary significantly from rates based on embedded costs.

Embedded costs are also known as accounting costs.

Energy Charge

E

See also: Customer Charge; Customer Costs; Demand Charge; Variable Costs.

One component of a customer's energy bill, along with the customer charge and the demand charge.

This charge recovers operating costs, including the costs of fuel used to generate electricity or the costs of gas purchased for delivery to customers. It varies with the number of kilowatt-hours or therms consumed.

Energy charges are also known as commodity charges.

The energy charge is one component of a customer's energy bill.

Pacific Gas and Electric Company
San Francisco, California

Revised Cal. P.U.C. Sheet No. 8597-E
Cancelling Revised Cal. P.U.C. Sheet No. 8486-E, 8487-E

SCHEDULE NO. D-1 -- RESIDENTIAL SERVICE

APPLICABILITY: This schedule is applicable to single-phase residential service in single-family dwellings and in flats and apartments separately metered by the Utility; to single-phase service in common areas in a multi-family complex; and to all single-phase farm service on the premises operated by the person whose residence is supplied through the same meter.

TERRITORY: The entire territory served.

RATES:

		Per Meter Per Month
ENERGY CHARGE:		
TIER I	BASELINE QUANTITIES, per kWh	$.05458
TIER II	TIER II QUANTITIES, per kWh	$.07102
TIER III	EXCESS, per kWh	$.09174

MINIMUM CHARGE: $2.00.

SPECIAL CONDITIONS:
1. ANNUAL CONTRACT: For customers who use service for only part of the year this schedule is applicable only on an annual contract.
2. BASELINE RATES: Baseline rates are applicable only to separately metered residential usage. The Utility may require the customer to complete and file with it a Declaration of Eligibility for Baseline Quantities for Residential Rates.
3. TIER I (BASELINE) AND TIER II QUANTITIES: The following quantities of electricity are to be billed at the rates for baseline and Tier II usage (see Rule No. 19 for additional quantities for medical needs):

BASELINE AND TIER II QUANTITIES (kWh PER MONTH)

Baseline Territory*	Code B - Basic Quantities				Code H - All Electric Quantities**			
	Summer		Winter		Summer		Winter	
	Tier I	Tier II	Tier I	Tier II	Tier I	Tier II	Tier I	Tier II
R	520	400	350	250	740	510	1,200	700
S	440	300	350	230	660	420	1,200	700
T	220	150	250	170	390	310	850	540
V	290	190	340	210	540	340	1,100	650
W	540	460	320	210	800	650	1,000	660
X	310	210	330	210	400	360	1,000	640
Y	350	250	360	250	480	310	1,200	790
Z	250	230	400	300	400	320	1,400	880

*The applicable baseline territory is described in Part A of the Preliminary Statement.
**Permanently installed electric heating as primary heat source.

4. Summer and winter Tier I (baseline) and Tier II quantities will normally be billed without seasonal proration for six consecutive billing periods beginning in the middle of the May and November billing cycles as described in Rule No. 9.
5. STANDARD MEDICAL QUANTITIES (Code M - Basic Plus Medical Quantities, Code S - All Electric Plus Medical Quantities): Additional medical quantities are available as provided in Rule No. 19.

Marginal Cost

See also: **Average Cost; Cost of Service; Embedded Cost; Incremental Cost; Rate Design; Revenue Requirement; Time-of-Use.**

From an economic perspective, the cost of producing an additional unit of goods or services.

In the utility industry, marginal costs are the change in total costs due to the production of one additional kilowatt (kw), kilowatt-hour (kwh), or therm. As a simple example, assume an electric utility produces 100 kw of power at a total cost of $500. If the utility produces another kilowatt, total costs of production rise to $512. The added cost to the utility of the marginal kilowatt is $12. This contrasts with the average cost which, at $512 for 101 kw, is $5.07 per kilowatt.

Marginal costs are important because they provide a measure of economic value used in making consumption choices and in motivating efficient resource allocation. In purchasing energy, the customer should be aware of the cost required to produce the energy. If the price in the above example is set above or below the $12 per kilowatt marginal cost, customers are not charged the true cost of producing the power. Only if price is equal to marginal cost are customers paying the actual costs of the increased demand they put on the system.

Marginal costs exclude expenditures that have already been made. Since it is the cost of an additional unit of output, marginal cost incorporates only the difference between total cost at the current level of output and total cost at an increased level of output. Present or future expenditures are not marginal costs unless they are associated with the production of the marginal unit. In the example cited above, the cost of producing the original 100 kw is not the marginal cost; the only cost considered is the $12 associated with producing the 101st or marginal kilowatt.

Marginal costs are "forward-looking" because they ignore historical or embedded costs. Since revenue requirements are based on embedded costs, the revenues collected with marginal-cost-based pricing will equal the revenue requirement only by coincidence. In the example, the utility's total revenue requirement will equal the total cost of producing all 101 kw ($512). However, if all 101 kw were priced at the marginal cost of $12 per kilowatt, the total reve-

nue collected would be $1,212, or $700 above the average-cost-based revenue requirement. If marginal cost is below average cost, revenue collected will be less than the revenue requirement.

This excess or deficiency of revenue must be returned to or collected from the customers with some form of revenue reconciliation. In the process of revenue reconciliation, the utility attempts to recover only the authorized revenue while retaining as much of the economic efficiency of marginal costs as possible. Possible methods of revenue reconciliation include:

- Refunding the revenue above the revenue requirement to customers in lump-sum payments.
- Reducing the rate charged for low-usage blocks of energy.
- Setting rates for each schedule based on the proportion of total marginal cost for which customers on that schedule are responsible.
- Adjusting rates above or below marginal cost for each class by a uniform amount per kilowatt-hour or therm.

While these adjustments detract from the economic efficiency of full marginal cost pricing, they are reasonable ways to balance the needs of economic efficiency, fairness to all customers, and the regulatory structure.

Utility marginal generating costs vary by season and time of day. Adding a unit of output during an off-peak period requires only additional fuel and other operating expenses. Additions to peak period production (unless the utility has excess capacity) ultimately require additional generation and transmission capacity. Time-of-use rates, which recognize the higher cost of production during peak periods, are consistent with marginal costs. Using marginal costs to set rates will yield higher rates (marginal costs) during peak periods; alternately, the peak period can be determined through marginal cost analysis. While time-of-use rates are consistent with marginal costs, they need not be based on actual marginal costs. Time-of-use rates can be created without studying true marginal costs at all; all that is required is a higher price for peak periods.

Electric marginal costs are used to design rates, evaluate conservation and load management programs, guide system resource planning, and set prices paid to cogenerators and small-power producers. Gas marginal costs are used in rate design, program

evaluation, fuel acquisition, and system planning. The California Public Utilities Commission (CPUC) established a marginal cost methodology in September 1979. Since then, PG&E has worked to improve the electric and gas marginal-cost methodologies.

Electric Marginal Costs

PG&E calculates the following marginal-cost components of electric service: generation, transmission, and distribution. PG&E makes no distinction between long-run and short-run marginal costs. Generation-related marginal costs are composed of a marginal cost of capacity (shortage cost) and a marginal energy (or operating) cost.

The marginal cost of capacity (shortage cost) measures the marginal value of system reliability to PG&E's customers. As a proxy for shortage costs, the CPUC has accepted the cost of building a gas turbine to meet loads when a potential shortage of capacity could be experienced. The cost of the gas turbine is adjusted by annual Energy Reliability Index (ERI) factors, to reflect year-to-year variations in system reliability.

The marginal energy (or operating) cost is the sum of the variable fuel and operation and maintenance (O&M) expenses of the marginal generating unit (the unit used to meet the last kilowatt of demand) at any time. PG&E computer models calculate the probability that any particular generating unit will be the marginal unit and apply that probability to forecasted fuel and O&M expenses.

Transmission marginal costs are based on a statistical analysis of the relationship between transmission system peak load, adjusted for geographic diversity, and changes in total transmission system costs over a 15-year planning period. Distribution marginal costs are based on both the cost of adding another customer to the distribution system and the increased distribution cost of a change in demand. The method for obtaining demand-related distribution costs is similar to that used for transmission.

The results of the marginal cost calculations are a set of marginal costs segmented into generation, transmission, and distribution categories, and broken down by voltage level within each category. These costs are then assigned to time periods: summer, winter, on-peak, or off-peak.

Gas Marginal Costs

The use of marginal costs in gas ratemaking is less elaborate than in electricity pricing. In calculating gas marginal costs, two types of costs are considered:

- The utility's operating costs, which may increase to meet additional demand.
- Customers' shortage costs, which may increase if additional demand either increases the risk of a shortage occurring or leads to actual service interruptions.

Thus, the marginal cost of gas service may be expressed as the sum of marginal operating cost plus shortage cost.

The marginal operating cost of delivering gas equals the sum of the marginal cost of gas purchases and the marginal cost of transmission from PG&E's marginal gas sources. The gas shortage cost is the cost of the risk of unscheduled interruptions occurring. The shortage cost is limited by industrial fuel-switching capabilities, which implies that the gross cost of a gas shortage can never exceed the cost of alternate fuel.

When the prices of alternative fuels are low in relation to natural gas, the marginal cost of gas can be below the average cost.

Monopoly

See also: **California Public Utilities Commission (CPUC); Economies of Scale; Federal Energy Regulatory Commission (FERC); Holding Company; Public Interest; Public Utility; Regulation.**

The situation of an individual or corporation owning or controlling so large a part of the market supply or output of a given commodity or service that competition is stifled and freedom of commerce restricted, giving the monopolist control over prices. To prevent the abuses that may result from this concentration of economic power, monopolies are generally forbidden by law.

Utilities, including railroads, telephone companies, and power companies, tend to gravitate naturally toward a monopolistic structure. This is why they are natural monopolies—enterprises that can, through economies of scale, produce more of a particular product or service at a lower cost by operating near full capacity on a large scale. Because economies of scale allow public utilities to provide economic advantages to society, the utilities' natural monopolies are permitted to exist subject to strict governmental regulation. PG&E is considered a natural monopoly, serving electricity to 82 percent of all households in Northern and Central California.

Electric and gas utilities require large investments of capital to build, maintain, and operate their generating and delivery systems. If two or more utilities were to compete in the same area for the opportunity to serve the same customers, expensive and duplicative systems would have to be built. Society has determined that it is most practical and least expensive to have only one utility providing service in a given service territory.

The history of public utility development in the U.S. aptly illustrates this point. In the late 1800's, the utility business grew rapidly, and entrepreneurs entering the industry frequently lost out to more aggressive competitors. Investors and consumers alike suffered as these new businesses failed, and the Supreme Court ultimately ruled to allow regulation of industries "affected with public interest." This legal decision (*Munn v. Illinois*, 1877) attempted to curb the abuses of power evident in the utility industry and eliminated competition that might threaten efficient production of a product or service.

Regulation is meant to control utilities. Through regulation,

society ensures that good, safe, and reliable services are provided to all customers at reasonable, nondiscriminatory prices. Regulators—in PG&E's case, the California Public Utilities Commission and the Federal Energy Regulatory Commission—determine a reasonable cost of doing business, including a reasonable return on investment, and set rates designed to recover those costs. Utilities are not guaranteed the rate of return found reasonable by their regulatory commissions. Rather, they must keep their expenditures within the allowances provided by these commissions if they are to have a reasonable opportunity to earn that return.

Thus, through regulation, society captures the economic efficiencies associated with natural monopolies but avoids the problems of monopolistic and discriminatory pricing.

Noncoincident Demand

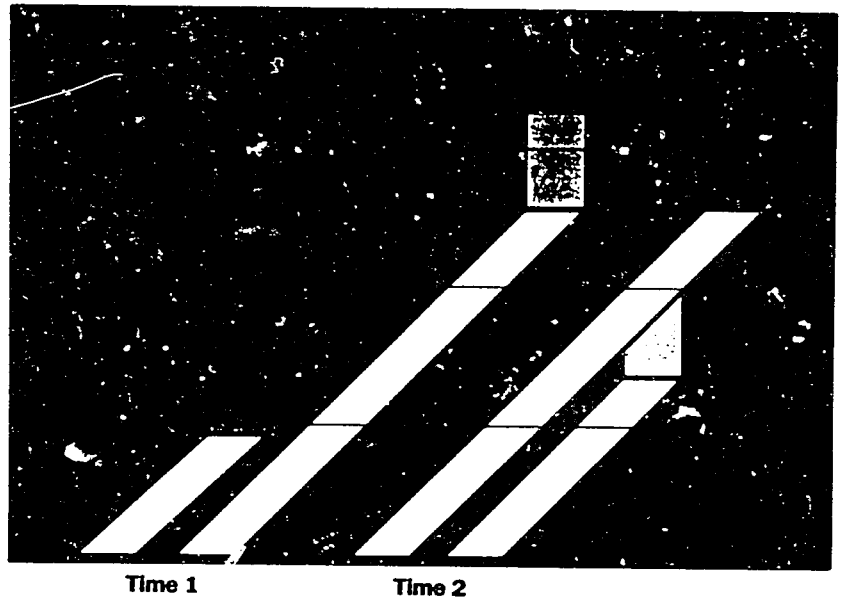
See also: **Coincidence Factor; Coincident Demand; Demand; Demand Charge.**

Maximum demand of a customer, or customer class, regardless of when it occurs. Generally, the noncoincident demand is used as the basis for calculating the demand charge.

The sum of the noncoincident demands in the accompanying example is 700 kilowatts (kw). This total is obtained by adding the maximum demand of 350 kw for Company A occurring at time period 2 and the maximum demand of 350 kw of Company B occurring at time period 1.

The maximum demand on a utility is not the sum of the noncoincident peak demands of its customers. This would only occur in the unlikely event that all customers experienced peak demand at the same time.

Noncoincident Demand



Company A's noncoincident demand occurs at Time 2; Company B's occurs at Time 1.

N

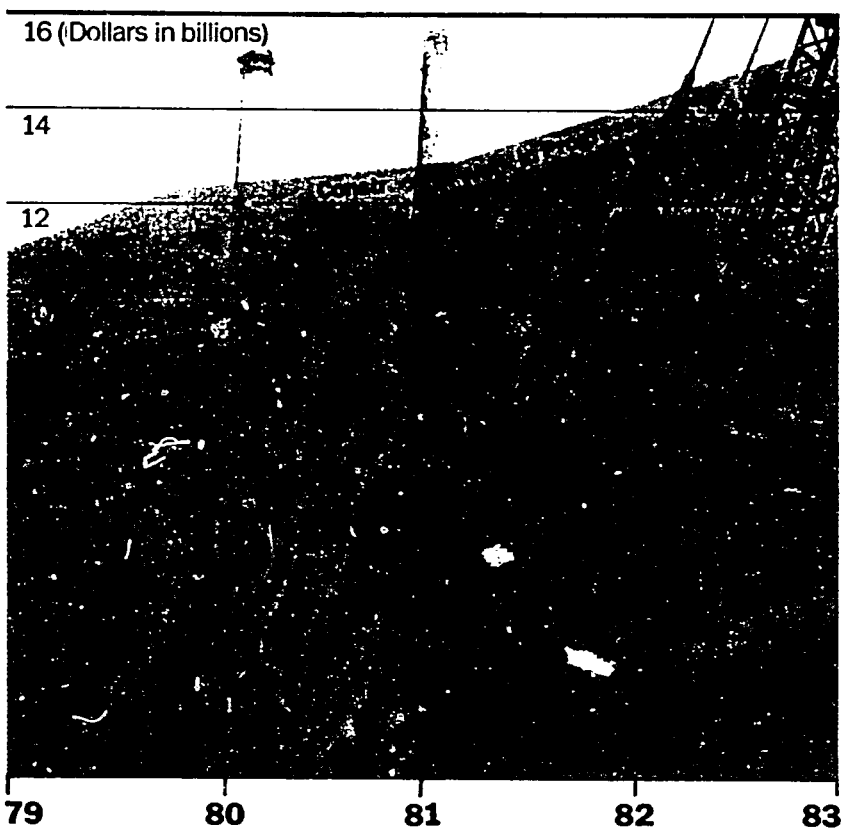
Plant in Service

See also: Balance Sheet; Construction Work in Progress (CWIP); Depreciation; Rate Base; Utility Plant.

Land, buildings, and equipment that have an economic life of over one year and are considered relevant to a company's current operations. Plant in Service does not include Construction Work in Progress (CWIP). When project construction is complete, the item of plant is transferred from CWIP to Plant in Service. Plant in Service is the largest component of rate base.

As of December 31, 1983, PG&E had $10.7 billion recorded on its balance sheet as Plant in Service before adjusting for accumulated depreciation.

PG&E Plant in Service & Construction Work in Progress, 1979–1983



Source: *PG&E Annual Report*, 1983, p. 23.

Rate Base

See *also:* Allowance for Funds Used During Construction (AFUDC); Capital Structure; Construction Work in Progress (CWIP); Depreciation; Rate of Return.

The accumulated capital cost of facilities purchased or installed to serve the company's customers and on which the utility is allowed to earn a return.

The three major components of rate base are:

- INTANGIBLE PLANT: includes the cost of all fees paid to various levels of government for the privilege of incorporation and for franchises, consents, patent rights, licenses, and other government-granted privileges. It also includes the corporation's organizational costs and costs associated with other intangible property rights necessary or valuable, not chargeable to any other capital account.
- TANGIBLE PLANT: includes the historical cost of all the land, equipment, plants, structures, and other physical facilities used by the utility to serve customers, less accrued depreciation. It also contains "Plant Held for Future Use," which consists primarily of land and land rights that have been acquired in advance of the

time they will be needed for construction of utility service facilities. These advance acquisitions are made to ensure availability of the properties at the time of need, and to avoid excessive cost-escalation because of urban expansion or saturation of the service area.

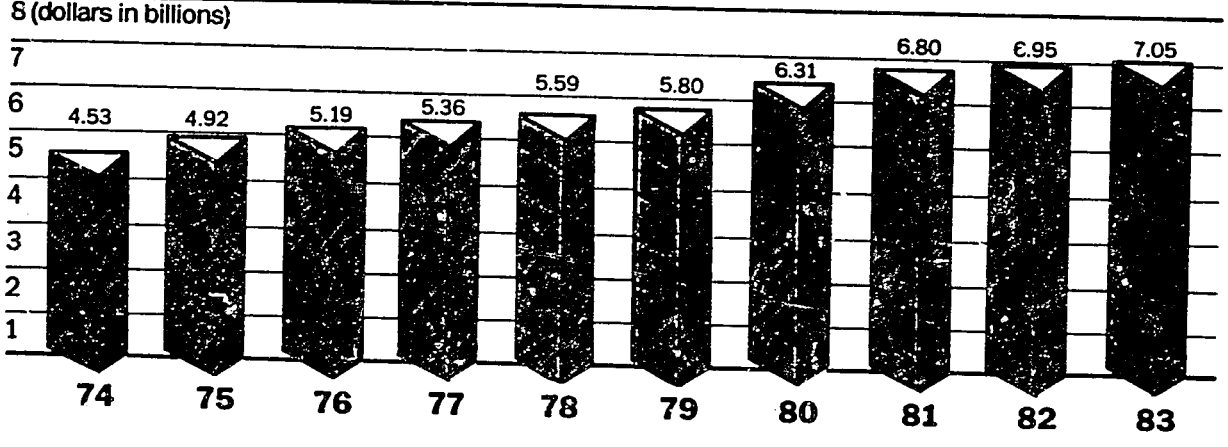
- WORKING CAPITAL: comprises investment in materials and supplies, current gas in underground storage, gas-line pack, prepaid gas, gas exploration funds to be capitalized, and an allowance for working cash. Working cash is included in rate base to compensate investors for the day-to-day cash funds they supply, enabling PG&E to operate efficiently and economically, and for which they would not otherwise be compensated, since cash is not classified as plant.

Facilities under construction are not included in rate base; thus, they neither affect rates nor earn cash income.

To arrive at total rate base, certain subtractions must be made from the amounts shown on the company's books. These adjustments are necessary because utility plant investments are recorded on the books at their actual construction cost, without regard to the sources of capital funds used to build them. Adjustments are made for the following circumstances:

- When contribution or advances to aid construction are provided by customers, these funds are deducted from plant investment because they do not represent funds supplied by the company's investors.

PG&E Weighted Average Rate Base, 1974–1983



Source: PG&E Revenue Requirements Department, Capital and Capital Recovery.

- Short-term company investments of temporarily available cash are not included in rate base because such capital is earning interest, and investors are already being compensated.
- Certain deferred taxes are also deducted from recorded plant, as they represent the company's previous tax earnings resulting from plant ownership.

Accrued depreciation—the accumulation of annual depreciation expense charged to customers in past periods—is also deducted. Since accrued depreciation represents capital already recovered, it must be subtracted to prevent rates from recovering capital costs twice. The remaining total is referred to as depreciated rate base, or simply rate base. It is this amount of investment on which the company is allowed to earn a rate of return.

Although PG&E develops its rate base for general rate case applications, the actual dollar value of rate base on which PG&E is allowed to earn a rate of return is established by the California Public Utilities Commission (CPUC) during general rate case proceedings. In rate base determinations, the CPUC sets an amount for each of the previously mentioned rate base components. In the 1984 General Rate Case decision, the CPUC authorized a $5,335,404,000 rate base.

Once the dollar amount of rate base has been determined, the utility is then allowed a rate of return on total rate base.

Rate Base (RB) multiplied by Rate of Return (ROR) equals Return (R):

$$RB \times ROR = R$$

PG&E's 1984 authorized return (or net operating income) is $664,257,798.

$$RB\ (\$5,335,404,000) \times ROR\ (12.45\%) = R\ (\$664,257,798)$$

In establishing both a rate base and a rate of return that are fair and reasonable, the CPUC attempts to strike a balance between the interests of the utility's investors, customers, and employees as well as the interests of the general public.

Tariff Schedule

T

See also: Advice Letter; Rate Design.

A document filed with the California Public Utilities Commission (CPUC) specifying lawful rates, charges, rules, and conditions under which the utility provides service to the public. Individual pages of the tariff schedule are referred to as tariff sheets.

The CPUC's General Order No. 96-A specifies the general format of tariff schedules and sets the procedures to be followed in filing and publishing them. As specified in General Order No. 96-A, a tariff schedule must contain certain items:

- PRELIMINARY STATEMENT: describes the territory served, types and classes of service rendered, and general conditions under which the service is rendered.
- RATE SCHEDULE: includes class of service, applicability, territory, rates, and special conditions.
- RULES: cover the application of all rates, charges, and service when such applicability is not fully set forth in the rate schedules. Some of the subjects covered in the rules are definitions, applications of service, contracts, establishment of credit, deposits, temporary service, and line extensions.

Sample forms, a list of contracts and deviations, service area maps, and the table of contents complete the tariff schedules.

Tariff schedules can only be changed after CPUC authorization, either through application or advice letter filing. For example, if PG&E has submitted an application for a rate increase, the tariff schedules cannot be filed, nor rates changed, until after the CPUC has announced its decision.

On the other hand, when the company has filed an advice letter and its associated tariff sheets, the CPUC staff has been delegated the authority to place the revised tariff sheets in the tariff schedule. In these cases, a formal application is not required. There can be a delay between the time the changes are proposed and the rates actually go into effect—a delay that can be as short as a few days or as long as several months.

Test Year

T

See also: Attrition; General Rate Case Application; Rate Design; Revenue Requirement.

A concept used in rate regulation where a 12-month operating period is used to evaluate the cost of service and adequacy of present or proposed rates.

Generally, the test year becomes the basis for general rate case calculations. There are two basic types of test years in use: historical test periods; and forecast or future test periods, which are used in California. Forecast test periods attempt to account for inflation and the resulting higher utility costs. They are useful in situations where the rate case is filed well in advance of the date when proposed rates will themselves be implemented, for they allow a utility to project future earnings and expenses and to design rates with these data in mind.

PG&E, for instance, is restricted by the California Public Utilities Commission (CPUC) from filing general rate case applications more frequently than once every two years. However, the volume of information in a general rate case application is immense, and the CPUC is required to review virtually all of it. Consequently, PG&E must submit its application 15 months before the proposed rate increase goes into effect, estimating its future needs a year and a half in advance. Using test years to project the necessary revenue requirement is a vital step in the ratemaking process if the requested rate change is to reflect the company's needs accurately.

Used and Useful

See also: Common Utility Plant; Construction Work in Progress (CWIP); Utility Plant.

A regulatory specification typically used to determine whether an item or plant may be included in a utility's rate base.

In Decision No. 83-12-068, the California Public Utilities Commission said, in part:

*Under these [used and useful] principles, ratepayers are required to bear only the reasonable costs of those projects which provide direct and ongoing benefits, or are used and useful in providing adequate and reasonable service, to the ratepayers.**

The used and useful concept excludes Construction Work in Progress from the rate base because these projects are not currently used to perform a service for the benefit of ratepayers.

*Source: *PG&E 1984 General Rate Case Decision*, p.46.

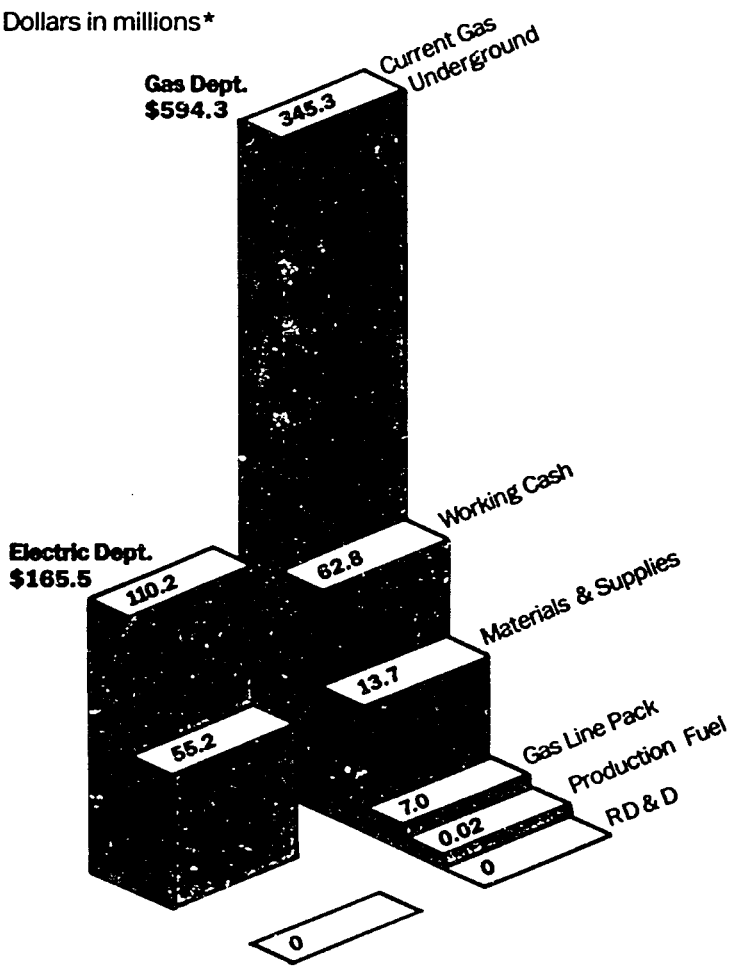
Working Capital

See also: Balance Sheet; Working Cash.

The funds representing necessary inventories of materials and supplies, and the cash required to meet current bills and maintain bank balances. Working capital is included in the rate base to compensate investors for the capital they supply to the company.

PG&E Working Capital, Test Year 1984

Dollars in millions*



In the 1984 General Rate Case Decision, PG&E's total working capital allowances were $760 million.

*These are relative numbers for comparative purposes only.

Source: PG&E 1984 *General Rate Case Decision*, pp. 203a & 259.

tories of materials and sup-
rent bills and maintain
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pply to the company.

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ing Cash

Materials & Supplies

Gas Line Pack
Production Fuel
RD & D

The amount of working capital required depends on several factors, especially the company's billing and purchasing methods. If purchases are made on credit, or customer payments are required in advance or at the time service is rendered, working capital requirements may be small. However, if payments for supplies must be made in advance, business is seasonal, or customers are billed monthly, quarterly, or semiannually, working capital needs may be large.

Included in PG&E's total working capital are: Materials and Supplies; Working Cash; Research, Development and Demonstration Feasibility Studies; Production Fuel (Gas Department); Current Gas Underground; and Gas-Line Pack.

The accompanying illustration shows PG&E's working capital allowances adopted for the General Rate Case Test Year 1984.

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