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INTRODUCTION

by

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The M.I.T. project on international gas trade is examining the forces affecting natural gas trade in the three major markets: North America, East Asia, and Western Europe. This report is on the North American unit, and has been divided into six elements: policy/regulation, supply, demand, contract issues, a small model used to simulate key factors, and a technical speculation on new uses for natural gas. The six background papers that follow deal with these elements. This introduction summarizes but also synthesizes the first four papers.

MARKETS IN TRANSITION

Canadian and U.S. natural gas markets are undergoing a significant transition. The suddenness of the change away from a highly structured, regulated system in both countries has caught many market participants by surprise. They therefore tend to be preoccupied with present conditions, which (as in any transition) are subject to twists and turns that frequently obscure the direction of change.

Our study must of course deal with the transition, but we have also tried to look beyond the current scene to understand how future markets for natural gas will operate. Some haze still hides the details, but we think those markets will be competitive and interconnected on a regional, national, and even continental level. Interfuel and "gas-to-gas" choices will turn on price and other contract terms between private parties, not on the outcomes of lengthy regulatory proceedings. This is both bad and good news for market participants. Gone will be the certainty of regulatory decisions and the familiarity of jousting in Washington or Ottawa to turn those decisions to one's advantage. But gone also will be the caprice and delays associated with the joust. Participants will have more control over their own fates--but those fates will depend more on market forces, including the fluctuations of world oil prices. There will be new business risks, but markets are far better at pricing and assigning risks than bureaucrats.

But as these markets are emerging from the transition, Canadian gas exporters still face soft demand and increased competition from declining oil prices and excess U.S. gas deliverability. Significant price cutting has halted the slide in export volumes and even turned it back up--though still below sales levels, of 6-8 years ago, and approximately one-half of <u>authorized</u> export volumes. Because of the price reductions, increased exports have yielded revenues little higher than those at the depressed 1983-84 levels. This price-volume-revenue relationship is a crucial one for producers, who must make decisions both on current production and on future investments in exploration and production. For policy makers, production royalty and income taxation revenues are greatly affected by changes in the price-volume nexus. Thus, a representative set of questions faced by Canadian exporters and policy makers might be:

1. How much must prices be reduced to retain, regain, or expand Canadian export sales?

2. Is the U.S. excess gas deliverability a temporary phenomenon, and if so, how long will it persist?

3. What is the prospect that the seeming long-term slide in oil prices will be reversed, thus lessening competitive pressures from fuel oil?

4. Because of these uncertainties, is it preferable to forego meeting price competition, and wait to see if demand and price increase in the future?

5. If that course of action is taken, how long will it be necessary to wait?

Unfortunately, there is no simple or certain answer to any of these questions. The effects of policies on both sides of the border have deranged the data for many years, so past experience cannot be used as a certain gauge to the future.

Nevertheless, these data are suggestive, and thus of some value. The body of analysis that follows makes good use of this history, and brings critical judgment to bear on characteristics and trends of the future. This brief report summarizes these papers, and highlights their conclusions.

POLICY IN A MARKET-CLEARING WORLD

Because we are in a period of transition, there is a tendency for regulators and policy makers in both the United States and Canada to be preoccupied with finding ways to avoid the pain of adjustment. Commendably, most now seem to be following the optimal solution, which is to try to stay out of the way.

Unfortunately, U.S. legislation has frozen many rigidities into place, so even regulatory attempts to loosen them are of limited efficacy. This creates both problems and opportunities for Canadian producers, but the opportunities are likely more abundant. Because Canada has a very large block of shut-in gas which is readily producible (perhaps 8 Tcf at low investment levels with another 5 Tcf requiring larger additional investment), entry into new markets is relatively easy for them. For example, low-cost Canadian production may provide a real advantage over the higher cost and structurally more rigid U.S. gas supply in competition for the California Enhanced Oil Recovery Market.

Since our analysis indicates that market clearing prices are declining while still sorting out, rigidities in policy which set minimum prices for gas trade may be keeping Canadian participation below that which would otherwise occur. Such matters as a single Alberta border price, Toronto city gate price, or no sales below competitive fuel prices, all inhibit markets from clearing--and may prevent a substantial amount of Canadian production from moving into profitable opportunities.

Because Canadian reserves appear ample to at least double current export levels for the forseeable future and because eastern Canadian market demand looks flat for the same period, provincial and federal 25-year reserve tests based on current year domestic use are anachronisms no longer serving original purposes. The carrying costs of a 25-year inventory are punitive.

Similarly, a single Alberta border price or a minimum Canadian export price are relics of earlier policy eras, and serve now primarily as rigidities slowing down the process of adjustment to market realignments both in Canadian domestic markets and in cross-border trade. While National Energy Board export pricing criteria have shifted toward increased flexibility in an admirable fashion, maintaining rules about such matters as competing fuel price tests substitutes regulatory judgment for market judgment. Clearly, a severing of the artificial connection between any domestic sales price and export prices will permit natural gas to find market-clearing levels in all markets. This price will move up and down over time as market circumstances change, and such flexibility is important in permitting gas to be a competitive fuel.

U.S. regulatory actions have also moved increasingly in the direction of letting markets operate more freely. Import rules by the Economic Regulatory

Administration are models of avoidance of tampering with commercial transactions. The Federal Energy Regulatory Commission (FERC) is also moving haltingly to disengage from a history of greater involvement. The May 1985 Notice of Proposed Rulemaking gives a clear signal, especially through the self-certifying provisions, of interest in less direct involvement in most contracts.

A lingering problem is that portion of U.S. gas supply left forever under price controls by the Natural Gas Policy Act. This low-priced gas is unevenly distributed among interstate pipelines, and those who have it are understandably reluctant to give up the subsidy bestowed. This price-controlled, old gas created distortions of all sorts, and the FERC has frequently been inclined to create off-setting distortions. To producers of this old gas, the incentive for increasing or prolonging production is also distorted. Unfortunately, change would involve legislative action, and the danger of mischief is so high that the potential benefits must be heavily discounted for that risk.

The excess deliverability in U.S. production finds a parallel in the take-or-pay backlog in Canada. Special Marketing Programs (SMPs), spot markets, and other devices are sorting this out in the United States. But the Canadian glut may result in more serious disincentives north of the border. Some mixture of permissive and coercive regulatory action may be required either (a) to clear the backlog or (b) to keep that backlog from quenching new exploration, development, and sales by those not now involved in the historic take-or-pay settlement arrangements.

Finally, Canadian policy is also showing increased flexibility in royalty and taxation treatment of production. In a world of falling energy prices, there are simply fewer economic rents to go around. It is quite possible that further reductions may be necessary to avoid discouragement of investment in gas resource exploration and development.

In conclusion, the analysis of policy structure suggests that while none may not be best, less and simpler is certainly better. With markets in transition, those market actors who must live with the riskiness of outcomes are probably best suited to deal with the uncertainty.

SUPPLY COSTS

Our analysis indicates the following broad characteristics about the Canadian and U.S. supply picture. The data in recent years are very erratic and show no clear trajectory for either supply cost or reserve additions. In light of the events described during the period of strong regulation and transition away from that, erratic behavior by producers is not surprising--and that behavior is what creates the data.

In spite of the noise and uncertainty of these data, certain conclusions can be reached with some confidence:

1. Canadian costs of exploration and development in Western basins are likely slightly inflated now, and will come down some before beginning a longer-term increase that reflects development of lower-quality (higher-cost) reserves;

2. Canadian reserves appear abundant through the next 20 years at the exploration and development costs indicated, even at production levels 2-3 times that currently underway;

3. Exports are not physically constrained by pipeline capacity in the short run, but a tripling of annual volumes would require capacity expansion;

4. U.S. supply costs are higher than Canadian, but also declining more rapidly in the near term. The same longer-run increase is to be expected, but with Canada's costs perhaps one-third lower (an advantage partially offset by transportation costs incurred in reaching some U.S. markets); and

5. Reserve additions in the U.S. lower 48 states have been erratic, but surprisingly robust. On average, they have remained constant. Declining consumption has had an impact on the reserves/production ratio, but there is no reason to think that this picture will change sharply up or down for the next decade or more.

In addition to historic data, one must also examine current behavior of producers. Since producers operate in an economic environment, they behave with an implicit (or explicit) discount rate. Thus, if producers or other investors expect U.S. gas supply additions to fall, or oil prices to rise--either or both circumstances tending to push gas prices higher--one would expect a falloff in development activity. This would indicate that future profitability is expected to be higher than in current conditions, <u>when adjusted by the discount rate</u>.

The fact is that 1984 development drilling reached record levels, and indications are that 1985 has been higher still (with increased efficiency). This suggests strongly that U.S. producers believe it is more profitable to develop and produce natural gas now at $2.25-2.75 (a representative range of new gas contracts) than to wait for the possibility of future price increases. If one assumes a 10% real discount rate (a reasonably robust assumption), then it appears that current developers do not expect the price to rise above $3.00 before 1987--otherwise, they would not be developing the production.

Since Canada is selling natural gas into the U.S. market, policy and behavior must take into account what is happening to U.S. supply price. Our analysis indicates that at a 10% real discount rate, gas held in the ground is a risky asset. Therefore, a Canadian decision to wait to produce for sales in the United States is inherently a risky strategy. If there were an expectation that by 1990-95 U.S. natural gas prices would increase dramatically (due to higher oil prices or other factors such as increased U.S. supply costs), then Canadian export prices would also be higher. However, if one has a unit of reserve that is now profitable at a price of $3.00 per Mcf (and costs to develop are $1.00 per Mcf), by 1990 the price necessary to achieve the same discounted value of revenues would be nearly $4.00 (in 1985$). By 1995, the price required for the same unit volume to yield an equivalent return to a sale today would be over $5.40 (in 1985$).

For Canadian decision-makers, both public and private, the question is: How likely is it that those prices will occur? When reviewing U.S. supply additions, directions in the oil market, and behavior of U.S. producers, one must conclude it is unlikely.

Of course, the nature of demand for natural gas in the U.S. market is also a factor, and we now turn to reporting conclusions of that analysis.

U.S. NATURAL GAS DEMAND

The same perplexities of transition from a regulated market to an economic market pervade any attempt to analyze natural gas demand. Because regulation kept the price below market clearing levels, behavioral data from the past offer little reliability for predicting the future. Thus, our analysis examines the forces affecting that demand, and will review plausible alternatives through the rest of the century. Demand scenarios can be done with greater precision, but whether the result is more reliable is open to question. The basic demand uncertainty derives from the following multiples of uncertainty of the forces affecting demand.

The first uncertainty is the nature of structural change, which may have occurred in large gas-using industries. There is increasing evidence that a large segment of U.S. industrial capital stock that is now idle will not be coming back. Instead of cyclical effects pushing natural gas use down, it may well be that the business cycle is operating from a permanently smaller industrial base, which is demanding less natural gas. After two years of very robust recovery, gas sales basically have only stopped their downward slide. If the economy weakens, gas demand will likely again drop in the short term. New industrial structures, equipment, and processes will continue to replace less efficient stock, and longer-term demand will reflect this change.

This structural effect on industrial load has a parallel in the residential market. Except for New England, the residential stock is relatively saturated. As a mature demographic unit, U.S. population growth will not increase demand. In addition, new housing stock is smaller, better insulated, technically more efficient, and continuing to be located in warmer climates, all of which appear to yield flat or declining demand. The commercial building stock is more widely distributed geographically, but still with a slight tilt to warmer climates. The same technology and efficiency changes described for residental stock also will affect the commercial sector.

The second uncertainty affecting demand in all sectors is the oil price. This is the most pronounced in the industrial sector, where perhaps one-half the large boiler stock has fuel switching capacity between gas and high- or low-sulfur residual fuel oil (and sometimes even with coal), depending on location. Indications are that nearly all new boilers are dual fuel capable, even while using less fuel per unit of output. In addition to the crude oil price itself, the price of residual fuel oil is sensitive both to world refinery operations and utilization rates of residual upgraders.

A third uncertainty is the broader interfuel competition in all sectors. While Clean Air Act changes may affect coal use, that fuel continues to keep a surprisingly large share in both the industrial and electric utility sectors. The latter in turn feeds into fuel choice in new residential and commercial units. In more southern locations, air conditioning becomes more important and heating less so, resulting in electricity becoming more attractive for space conditioning. Also, efficiency and reliability advances in electric heat pumps have resulted in a spread northward for this technology. In industrial use, electro-processing and steel mini-mills are growing even while integrated U.S. steel production is falling.

Finally, feedstock use of natural gas will more likely decrease than go up. New U.S. petrochemical plants are not commercially feasible, and old ones will become more efficient or shut down in the longer run as competitors in the Persian Gulf or Latin America come on-stream.

All of the above factors suggest, at current delivered price levels, a declining demand for natural gas for the next several years, and even for the rest of this century. The upside potential depends on more speculative outcomes. First, the U.S. economy would have to have not only continued recovery, but sustained growth at a level that would call back idle, less efficient plants now unlikely to be utilized. Second, the oil price would have to increase both substantially and suddenly, causing existing users to switch to gas if resid prices jumped. Third, some form of air quality emergency might require a quick switch to gas. Otherwise, any change in the clean air legislation would likely have a several years phase-in, with only a gradual impact on demand for gas. (A more probable outcome in the region affected would be a greater call on imports of electricity from Quebec and other eastern Canadian points.)

One possible increase in natural gas demand could be the electric utility sector. Use of combined-cycle turbines for modest capacity expansion has shown theoretical attractiveness. Even in that case, a combination of technology development, utility decision making and some lifting of the FUA prohibition against natural gas use in new large boilers would be required to effect this new potential demand.

The results of this analysis would suggest a plausible range of U.S. natural gas demand by 1995 or 2000 of 15-18 Tcf per year. The lower end of the range would be caused by rigidities in regulatory systems, and other events that cause gas prices to be higher than market-clearing levels--resulting in successful competition by oil and coal. The higher end would see gas markets clearing, but prices following a declining demand curve, plus new markets such as cogeneration.

Thus Canadian producers are facing a U.S. natural gas demand that certainly is shrinking per unit of total GNP, and perhaps is declining absolutely. Price reductions will likely be necessary to hold current gas markets, and will certainly be required to increase sales. The extent of those price reductions will directly affect the size of demand, especially in new market segments such as cogeneration. These new prospects occur intermittently, and if not responded to will decide on other sources of gas or other fuels. The implication is that while a producer strategy of delay is inherently risky, as we have discussed, it is especially so when a new market sector appears.

DISCOUNT RATES, PROJECT TIMING, AND LONG-TERM CONTRACTS

In this part of the analysis, we examine why discount rates are important, how they are derived, and how to distinguish them from estimates of mean revenue streams.

Because the timing of the development of a natural gas project is a central question, it is necessary to calculate the present value of revenues flowing from that decision. The discount rate allows one to compare the present values of differing streams of future revenue. The risk-adjusted discount rate allows one to accomodate the riskiness of those revenues flows.

Reviewing other literature done on the riskiness of Canadian oil and gas assets, a 10% risk-adjusted discount rate (in real terms) was derived (though thought to be on the low side). Because lower inflation has moved the measured riskless rate from less than 1% toward 3 or 4%, it may be that a 12.5% real discount rate is more appropriate, although in our judgment this change is not warranted.

Because the real discounted rate is compounded, it already incorporates the view that later revenue streams are less certain (more risky). It should be noted that for Alberta, the discount rate may need to be even higher. Because this province is so dependent on oil and gas revenues, their exposure to risks of market losses is greater than Canada at large. Thus, calculating the cost of delaying a gas project in Alberta should arguably have a higher discount rate to reflect this risk. However, for this analysis, we continued to use the 10% real rate.

In considering the question of timing for production or investments in productive capacity, alternative cases from the demand analysis paper were utilized. Based on these options, and assuming a relatively flat demand curve, delay in production of developed gas reserves would require substantial future price increases to offset the effect of the discount rate. If new investment is required, pressure on net profits at the margin increases the attractiveness of postponement. Finally, if the demand curve is steep at lower price levels, a Canadian policy that could ensure higher future prices would obviously suggest a delay in investments (or even some production) to a future point; a flat demand curve would argue against delay.

The one certain circumstance to decide to delay production is when current profitability is uncertain. Therefore, a decision not to invest now preserves the option to do so in the future if conditions change to indicate a profitable investment can be made.

Finally, new modes of contract formats are explored, including front-loading take-or-pay arrangements. The analysis shows alternative ways of structuring a project that requires facilities to be paid for by revenues flowing from the project. In such cases, take-or-pay contracts ensure repayment, but shift much of the risk to the purchaser of the gas instead of on the producer--who is supposed to take the risk--especially in later years when price and demand are less certain. Front-loading of the take incorporates maximum revenue flow when the risk is at its lowest (assuming knowledge is greater about the next 3-5 years than that 15 or 20 years from now). Use of front-loading take-or-pay contracts will make possible the penetration of markets at higher prices than would be possible using traditional contracts.

CONCLUSIONS

Returning to the questions posed at the beginning of this essay section, we indicated that no certain answers could be quantified. However, as you read the following papers, the general answers become reasonably obvious.

1. Price Reductions. There is no single or simple answer, but Canadian gas prices will need to be at or below the price of fuel oil (both numbers 2 and 6) and U.S. gas supplies being offered in that market. To expand the market, Canadian gas will have to be priced below those prices, sometimes well below.

2. "Gas Bubble." Its persistence is a testimony to everyone's misestimations. It may be the new market for some years rather than a transient observation. See #4 and 5 below.

3. Oil Price Directions. This project did not analyze oil prices directly, but with new production capacity being added even as oil demand sags, any price recovery in oil markets is a long way off.

4. To Wait or Not? The analysis in the papers that follow suggests that waiting is a very risky strategy, unless a project is not profitable under current conditions. Observation of U.S. producer behavior in conditions of falling prices suggests that prices will not increase either dramatically or soon.

5. If to Wait, How Long? Holding proved reserves has carrying costs, which increase if production facilities are installed. Thus, waiting is not cheap, and real discount rates are stern masters. Avoiding competitive markets now does not help gain experience for the future.

I hope this summary will invite you to read the more detailed papers that follow.

A FINAL NOTE

To close this introduction, a brief word is offered on the final two papers included in our study.

A natural gas trade model was developed as a tool for public and private policy analysts, and its structure is described in the paper by Charles R. Blitzer. Time and resource constraints required that the model structure be kept simple, but the complexity of natural gas markets and policy required that it also be dynamic to reflect key issues raised in our analysis. We did not use this model as a forecasting device, and we believe its value is greatest as an analytic tool which forces rigor and consistency of assumptions.

The model does allow exploration of varying policy options based on alternative assumptions about exploration, development and production costs, U.S. and Canadian demand, transportation rates, discount rates, export volume restrictions, and other such matters. This feature is illustrated by Arthur Wright in Part II of the Model paper, where different demand and supply assessments, fiscal regimes, and behavioral assumptions are explored. John Parsons uses the model to explore how changes in the discount rate assumption might make an impact, and the effect on the value of revenue streams by decisions to delay production. He illustrates how the model can explore both producers' perspective on delay in a competitive market situation, and a Canadian government monopolist strategy of delaying exports to the benefit of that country, based on alternative assumptions given to the model. We hope this model will be a useful tool to be utilized by those who are involved in making decisions regarding North American gas trade.

The last paper is a look at how new technology might affect natural gas use. Technology change has had dramatic impact on natural gas supply, especially in offshore field development, and we thought it important to reflect on how scientific and engineering advances might alter the demand for natural gas. The demand paper noted how efficiency changes among others have reduced demand; the final chapter speculates on how demand might be increased through technology channels.

It is hoped this brief introduction will be a useful starting point in your reading of this report.

POLICIES, LAWS, AND OTHER COMPLICATIONS

by

Loren C. Cox

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INTRODUCTION

Other segments of this study analyze fundamental questions of supply costs and interfuel competition. Lamentably, natural gas markets in North America have, for a long period, been dominated by nonmarket, noneconomic factors. Indeed the history of natural gas markets is characterized by interventions from governments at all levels.

Such interventions have had several effects over time. The most striking impact is that they have rendered the concept of an open market almost without meaning. Normal economic signals affecting exploration, reserve additions, production, transportation and end-use competition have been blurred beyond recognition. Thus, natural gas markets have been subject to prevailing views of surplus, shortage, gas as a premium fuel to be allocated to premium uses, risk of damage to other fuels' competitiveness and so on.

However, the environment for natural gas has changed dramatically and suddenly over the past five years. Fundamental market forces have been reasserted, and gas is now in an unprecedented struggle to remain competitive in interfuel markets. Participants at all levels of the supply system are forced to act and react in unfamiliar ways. Producers, transporters and distributors in the United States and Canada are faced with the need to go out and <u>sell</u> natural gas[1]. It is a drastic change from the order-taking seller's market that characterized most of the previous two decades.

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[1]Mexico has of this date ceased sales to the United States. The future of Mexican exports of natural gas is at least uncertain and probably unlikely.

The basic market forces now at work are sending new signals throughout the system, and we observe willing sellers and willing buyers talking to one another. Unfortunately, effecting transactions is proving difficult and elusive, largely because of the residuum of laws and regulatory practices remaining in place from earlier times. Though regulation is also changing, the pace of that change is painfully slow, and frequently appears to be the most prevalent impediment to market activities.

This section will identify some of the most striking and obvious interventionist elements still affecting natural gas markets. Both U.S. and Canadian factors will be identified, with a special attention to those which affect transactions across the border in both directions.

The analysis will be normative, because it is most difficult to estimate quantitative effects with real precision. However, the model we use in the analysis can illustrate at least order-of-magnitude impacts or the present value foregone if regulatory action reduces sales that otherwise might occur.

Important U.S. Regulatory Milestones

Natural gas has been sold into nearby local U.S. markets from shallow wells discoveries since late in the 19th century. Because manufactured gas (town gas) was well established east of the Mississippi River, gas from these eastern fields (Appalachian) was readily accommodated into the supply system.

The great central fields in Oklahoma were discovered and made ready for market by the 1930s. Because the shallow eastern deposits were declining, long distance pipelines were laid to connect eastern and midwestern consuming areas from the new fields.

Initially, disputes arose primarily concerning access to this gas supply, and because the pipelines crossed state boundaries, state regulatory authorities were unable to resolve the conflicts. This gave rise to the Natural Gas Act of 1938, which extended federal jurisdiction over interstate gas pipelines. The central concern at this time was providing access to the pipelines.

Price matters did not arise at the federal level until the U.S. Supreme Court ruled in 1954 that federal regulatory authority for interstate natural gas sales extended to wellhead pricing (Phillips Decision of 1954). Under prevailing regulatory practice, this tended to mean that review was utility-like, with cost of discovery, rate of return and adjustment for inflation key factors in setting prices. A major result of this decision was a split market for locally produced gas. If a producer sold to an interstate pipeline, the price of the gas was regulated; if it were to an intrastate system, the price was set by local competition only.

While this bifurcation of markets had several effects, one of the most significant was the impetus for the establishment of new energy-intensive industries in gas producing areas. Shorter transport distances and multiple suppliers produced competitive prices and ample supply. This structural change became increasingly important in later legislative and regulatory battles, and foreshadowed more recent trends in Canada as well.

Robust intrastate demand and producers' unsurprising reluctance to commit production to interstate pipelines where price was controlled yielded a predictable shortage of cheap interstate gas. Thus, federal and state regulators were put into the difficult position of allocating those regulation-induced shortages among customers.

Allocation of supply was made more palatable if one could argue that there was actually a shortage of the resource itself. Assisted by the OPEC embargo and a general perception of resource scarcity in the 1970s, consumers looked to the cheap price-controlled gas to replace ever more expensive oil.

This, of course, exacerbated the demand for gas in interstate sales, with little increase in incentives for producers to contract for such markets. This in turn further increased the tension between inter- and intrastate markets.

By 1978, even the U.S. Congress recognized that control of gas prices (which produced shortages in the mid-1970s) was working no better than control of prices of domestically produced oil. Allocation of supply was proving politically embarrassing, and a new approach was clearly in order. The Natural Gas Policy Act of 1978 (NGPA) temporarily extended price controls to the intrastate market (in order to reintegrate the two) and set out a schedule permitting prices to rise to what was seen as market clearing levels. This involved decontrolling certain vintages of gas in January 1985, and immediately removing price restrictions on gas discovered below 15,000 feet (deep gas) or in certain tight formations. Altogether the legislation described over 20 categories of gas which were taxonomic relics of past regulatory actions.

The decision to exempt deep and tight sands gas was to have significant and continuing impact on interstate pipelines and markets. We will return to this matter shortly, since the reverberations of that decision are still affecting the current situation. Two other 1978 laws will be noted before that discussion.

Because of the perception that natural gas resources were dwindling, Congress passed the Power Plant and Industrial Fuel Use Act (FUA), which prohibited new large industrial and utility boilers from using natural gas. This fuel was seen as too "precious" for such applications, even though existing boilers could continue such use until 1990 when they were to switch to other fuels, especially coal. (This latter switching requirement was removed in 1980.) In view of the political force represented by residential natural gas customers in the United States, it is no surprise that lawmakers opted to "reserve" gas for such residential and commercial use.

However, the continued restriction against new large boiler use of natural gas is a distinct anomaly in today's glutted market. Improvements in technology for gas turbine, combined cycle electrical generation have made the "gas option" highly attractive to utilities. Faced with excess generation capacity, and uncertain electricity demand (and most of the uncertainties around peak demand), adding incremental generation capacity in relatively small units has obvious appeal, especially with the flexibility of combined cycle. Elsewhere in this paper we estimate a range of demand and costs which indicate why it may make sense to annul this legislation.

Just as FUA restricts natural gas markets, another 1978 relic creates artificial opportunities. The Public Utility Regulatory Policy Review Act (PURPA) was an attempt to nudge state regulatory practice into more uniformity, especially regarding incentives for energy conservation and fuel switching. However, the most striking impact was the incentive it gave for gas-fired cogeneration. PURPA required that electric utilities purchase cogenerated electricity--from whatever fuel--at the full avoided cost of expanding their own generation capacity. Because electric utilities were faced with capital and fuel costs for only three options--coal, oil or nuclear--the full avoided costs were high by almost any calculation (some were as high as $.14/kWh). Electric utilities are foreclosed by FUA from considering gas for new generation, and are largely prohibited from cogeneration ventures themselves, so nonutility cogenerators have the field to themselves.

The lingering set of restrictions against and incentives for natural gas use adds to a very complicated set of forces working on U.S. interstate pipelines. As mentioned earlier, deep gas was exempted from price controls in 1978, even while old gas prices were being allowed to increase under NGPA. The formula for increase was a specific percentage per year (based on gas category), plus an adjustment for inflation.

There was (and is) no uniformity of gas cost among interstate pipelines in the United States. Because they function in a purchase-for-resale mode, the average price of gas they deliver to local distribution companies is the sum of past contracting practices plus the distance of transportation, plus the age and size of their fixed assets. Because of past price controls, most intersates had found it difficult to keep their system full. Thus, when they had access to a supply source without price controls (deep gas), a spirited bidding war broke out. Since they were able to "roll in" the higher priced new supply into the cushion of price-controlled gas, it was thought the average delivered price would remain competitive. A quote from the Report of the House of Representatives when this legislation came to the floor shows the thinking of that time:

> An analogy may be useful to illustrate this point. Conceive of an interstate pipeline system as a tub of water. In the tub are many people representing the natural gas users served by the interstate pipeline. The temperature of the water in the tub is related to the price of natural gas. The pipeline desires to fill the tub as full as possible so long as no one gets out of the tub because the water is too hot. The first person to leave the tub is the user who is most temperature sensitive. Thus, the pipeline can add comparatively small quantities of hot water, representing higher priced new natural gas, to the cool water in the tub, representing the base of old price-regulated natural gas in the system, without raising the temperature of all the water in the tub to a level at which anyone gets out of the tub. In fact, if the quantities of new water added to the tub are sufficiently small, the temperature of the added water may be scalding hot but nonetheless would be rapidly diluted by the larger quantity of cooler water already in the tub.
>
> Under this analogy, it becomes clear that an interstate pipeline will be able to bid extremely high prices for new supplies of natural gas, which even deregulation proponents concede will be relatively small as compared to the volumes of presently flowing natural gas. The interstate pipelines, unlike the intrastate pipelines, are not constrained by a limited demand for natural gas. Using rolled-in pricing, interstate pipelines can bid the price of new supplies of natural gas to unprecedented levels of $5 per Mcf or more.[2]

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[2] National Energy Act, Committee on Interstate and Foreign Commerce, House Report 95-496 (Part I), p. 99.

Needless to say, the water in the tub did get too hot. The period 1978-1982 had unprecedented, high inflation rates, so the base price of the old gas contract cushion shot up. When combined with the $9-10/Mcf prices for deep gas, the average delivered price to distribution companies exceeded the price of competitive fuels. Large, price-sensitive industrial and commerical customers began switching to fuel oil and even coal. These defections by large end users threw fixed system costs onto a smaller customer base, further increasing delivered gas costs to those still in the system.

The response by interstate pipelines, after some confusion and delay, was to invoke "market out" clauses in contracts where allowed, and to declare *force majeur* where no such provision was in contracts. By setting new contract terms for deep gas at lower prices (first in the $5.50 range, then down to $3.50) pipelines struggled to bring their average costs down to prevent further customer losses--and eventually to regain some industrial load. Of course, with prices on the increase, there was a serious threat of price controls being reimposed under a provision of NGPA, and this provided a powerful incentive to pass price signals back to the producer--unilaterally if necessary.

At the same time as these events were occurring, Canadian energy policy was changing in ways that brought additional stress to the system. We now turn to that.

Canadian Policy

In certain ways, Canadian regulation and policy has been simpler because natural gas markets have been in existence for a shorter time (the largest major gas finds in Alberta were after 1947). But two other factors complicated matters. First, the constitution (British North American Act of 1867)[3] gave

[3] A most useful discussion of the history and functioning of Canadian regulation is found in *The North American Natural Gas Industry*, The Royal Bank of Canada, Global Energy and Minerals Group, 1984.

mineral rights to existing provinces, including direct taxation authority. Legislation in 1930 extended mineral rights to Alberta (except for pre-existing freeholdings--such as the Hudson Bay Company). This allocation of powers has remained a significant point of contention, especially in view of the second factor. The federal government controls both international and interprovincial trade, thus effectively regulating all gas moved out of a province. However, because the producing provinces (especially those with exportable surpluses--Alberta and British Columbia) are geographically distant from the major Canadian markets (Ontario and Quebec), this provincial-federal conflict assumed many aspects of the producer-consumer struggle in the United States. Thus, the separation of power and the separation of producers and consumers set the stage for development of Canadian regulatory actions.

Before the discovery after 1947 of large nonassociated gas fields in Alberta, provincial regulation there was designed primarily to ensure utilization of associated gas from oil production. After the new gas discoveries, Alberta was forced to deal with the federal government in order to sell gas outside the province. The first step was to affirm that it would have first access to its own production, thus laying the groundwork for the concept of "exportable surplus"--a concept that has dominated Canadian export policy at both provincial and federal levels. The legislative basis for this concept was established in 1956 by the "Alberta Gas Resources Preservation Act". The aptness of this title will be discussed later in this analysis.

Prior to the large Alberta discoveries, eastern Canada had imported natural gas from the United States; the Alberta reserves were so large that intraprovincial markets would be swamped, and nearby U.S. markets were not well developed. Thus both Alberta and federal interests converged on a domestic transportation route. With the completion of an Alberta-to-Toronto pipeline by

TransCanada PipeLines in 1958, western reserves were "committed" to eastern provinces.

With this west-to-east linkage, western producing policies on export volumes and prices became fully integrated in practice with federal decisions and policy. It is thus no surprise that eastern Canadian population centers and markets have dominated Canadian export decisions to the present.

The body responsible for regulatory action on interprovincial and export decisions is the National Energy Board (NEB), established in 1959. It has broad responsibilities both for regulation of electricity, oil and gas, and to advise the federal government on policies for development, conservation and use of energy resources--including export volumes and prices (and imports as well). We will return to the role of the NEB in North American markets from time to time in this discussion.

For now, we will examine the 1980 National Energy Program (NEP). The most striking quality is how the NEP was pervaded by so many of the same perspectives that characterized U.S. oil and natural gas policy actions through the 1970s. Principal concerns were about resource scarcity and securing national resources for domestic use (and federal access to revenues generated by non-federal resources). Preoccupied by the second sharp OPEC price increase in 1979, the NEP put a cap on Canadian oil prices. To keep stimulate interfuel competition (and to keep markets for gas), natural gas prices were allowed to rise over time--but not above 65% of the oil price at Toronto City Gate. (As in the United States, rising gas prices were in danger of exceeding oil prices, which by 1982 were on the way down.)

As a follow-up to the 1980 framework of NEP, a 1981 memorandum of agreement between the federal and Alberta governments produced a number of tax measures, two of which affected natural gas sales. The Petroleum and Gas

Revenues Tax (PGRT) was in economic effect a federal royalty (16%) on production; a subsequent federal/provincial agreement in 1985 phases out this tax. The Natural Gas and Gas Liquids Tax (NGGLT) was the mechanism used to achieve the 65% gas/oil price parity. The fall in oil prices and the 1985 agreement also removed this tax.

The above paragraph illustrates the federal/provincial entanglement on both policy and revenue. As such, it is not greatly different from the tensions between U.S. producing and consuming states. The element which is different is how this tension affects natural gas export decisions. The Alberta perspective[4] is that sale of its natural gas goes first to Alberta, then to exports to any other consumer--so long as exports from Alberta yield the same netback. The federal perspective is that natural gas is a Canadian resource, and assurance of national use, with a reasonable return to Alberta, should come before exports outside of Canada.

This federal perspective was embodied in the NEP initiative to switch end users from oil (considered to be oil imports) to "more plentiful Canadian energy sources" (NEP, p. 53). A set of grant and subsidy programs was established to convert away from oil, special low gas prices were established for large users, and extension of a pipeline to Quebec. These programs, together with the 65% gas price parity relationship with oil at Toronto, were designed to stimulate demand for Canadian gas in Eastern Canada. This stimulated demand became the critical measuring point for determining the 25-year reserve test, which in turn was the basis for determining the "exportable surplus" that allowed Alberta exports to the United States. We will return to the question of both Canadian demand and the exportable surplus later in this discussion.

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[4] In subsequent references to producing provinces, Alberta, which has 80% of the current reserve base in Canada, is the major actor. British Columbia is also an exporter, but will be identified separately in the discussion.

There is another important historical circumstance affecting the current situation. The completion in the late 1950s of the trans-Canada pipeline by TCPL, together with the priority Canadian use, put TCPL in a utility-like role with respect to gas purchases. In effect, TCPL had a monopoly on purchases for eastern Canadian use, and by 1982 held nearly 50% of all authorized contract volumes leaving Alberta. This represents a pool of gas contracted for, but not likely to be demanded in eastern Canada for the foreseeable future. This situation has a severe chilling effect on new exploration, since there is no obvious buyer for gas to be drilled and discovered in the near future.

With the only drilling for natural gas likely to be that required by lease and contractual agreements, there is the dangerous possibility that policymakers will look at current drilling and discovery rates and draw the erroneous conclusion that scarcity again looms. Alberta has a 25-year "exportable surplus" test that considers (1) existing contract commitments and (2) forecasted future requirements of use within Alberta.[5] This is determined by the amount by which known reserves and trend additions to reserves are in excess of those two factors. If a strong disincentive to drilling exists, it is easy to see future policy decisions being affected by how the remnants of past policy and practice impact on exploration/development decisions.

We conclude this section with a final word about the past pricing policy. In the 1960s, Alberta export prices were market related, so the province was concerned fundamentally with the export volume issue previously mentioned. A 1972 report by the Alberta Energy Resources Conservation Board (ERCB) expressed concern that field prices of gas were below the "commodity value" levels of other fuels.[6] With the first OPEC oil price shock, this disparity increased and

[5] The North American Natural Gas Industry, p. 117.
[6] Ibid., 121.

by 1975 the federal and Alberta governments agreed on a Toronto City Gate price of C$1.25/Mcf. This was established as the price base, and this price then was deemed to be 85% of the domestic oil price, thus also fixing the gas price linkage with oil. We have already noted that the 1980 NEP reduced the linkage to 65% to encourage use of Canadian gas in place of imported oil.

Interestingly, in 1977, the NEB proposed that gas exports to the United States be set at prices competitive with various fuels in separate U.S. markets. The U.S. government rejected this notion and asked for continuation of a uniform export price, arguing that differential prices "discriminated" among U.S. distributors. Thus began a uniform border pricing practice that was embodied in the majority of existing export contracts (even though renegotiations are now being permitted). It is simpler to quote the formula as issued than to explain it. Export prices are:

> . . . determined by taking the cost of imported oil at Montreal without the subsidy, adding the toll from Montreal to Toronto, deducting the cost of transmitting gas from Alberta to Toronto and adding on the average cost of transmitting Canadian gas to the international boundary. . .[7]

This concludes a review of some key historical determinants affecting current markets and ongoing policy debates. We now turn to consideration of those matters now affecting natural gas markets and international trade in gas. We will refer back to this section, for many of the complications are rooted in this history. Since the experience of the United States and Canada was different in the past, and the regulatory and policymaking process was different, ignoring it is a perilous course.

CURRENT POLICIES AND INTERACTIONS

In the last section we traced the separate histories of Canadian and U.S.

[7] Report to the Governor-in-Council in the Matter of the Pricing of Natural Gas Being Exported Under Existing Licenses, National Energy Board, Ottawa, Canada, January 1, 1980.

regulation and policy development. We now turn to the current situation and examine how the systems function and how they interact. Since regulatory events are moving rapidly in both countries, what is committed to paper may not be accurate in every detail six months from now--or even six weeks. However, the element in which we are especially interested is the perspective from which decisions are being made, and it is unlikely that this will change so quickly.

Since this project is concerned with the international trade of gas, those actions will be stressed. As noted earlier, Canadian policy also considers domestic demand requirements as a precondition to export (together with a current Toronto City Gate price), so we also must examine that current domestic policy situation.

The Current Market

In our historical review we mentioned the rapid changes occurring in natural gas markets over the past five years. The U.S. market is described as experiencing a "gas bubble," or a situation in which current deliverability is in excess of current end-use demand. Other parts of this report analyze the changes in demand that have occurred, and address potential future demand at alternative prices. Indeed, this is the crux of what has happened in the U.S. market: As delivered gas prices rose, they passed the point at which large users would switch to other fuels. These industrial and electric utility users are very price sensitive, and as fuel oil and other alternatives became cheaper, and the price tracks of the two fuels seemed to be diverging, these users switched.

Because residential demand is unlikely to grow nationally in the United States (though some shrinkage in one geographic area may be balanced by growth in another; see Table 1 and Figure 1), the only opportunity for substantially

TABLE 1

U.S. ENERGY CONSUMPTION BY THE RESIDENTIAL/COMMERCIAL SECTOR
(MARKET SHARE)

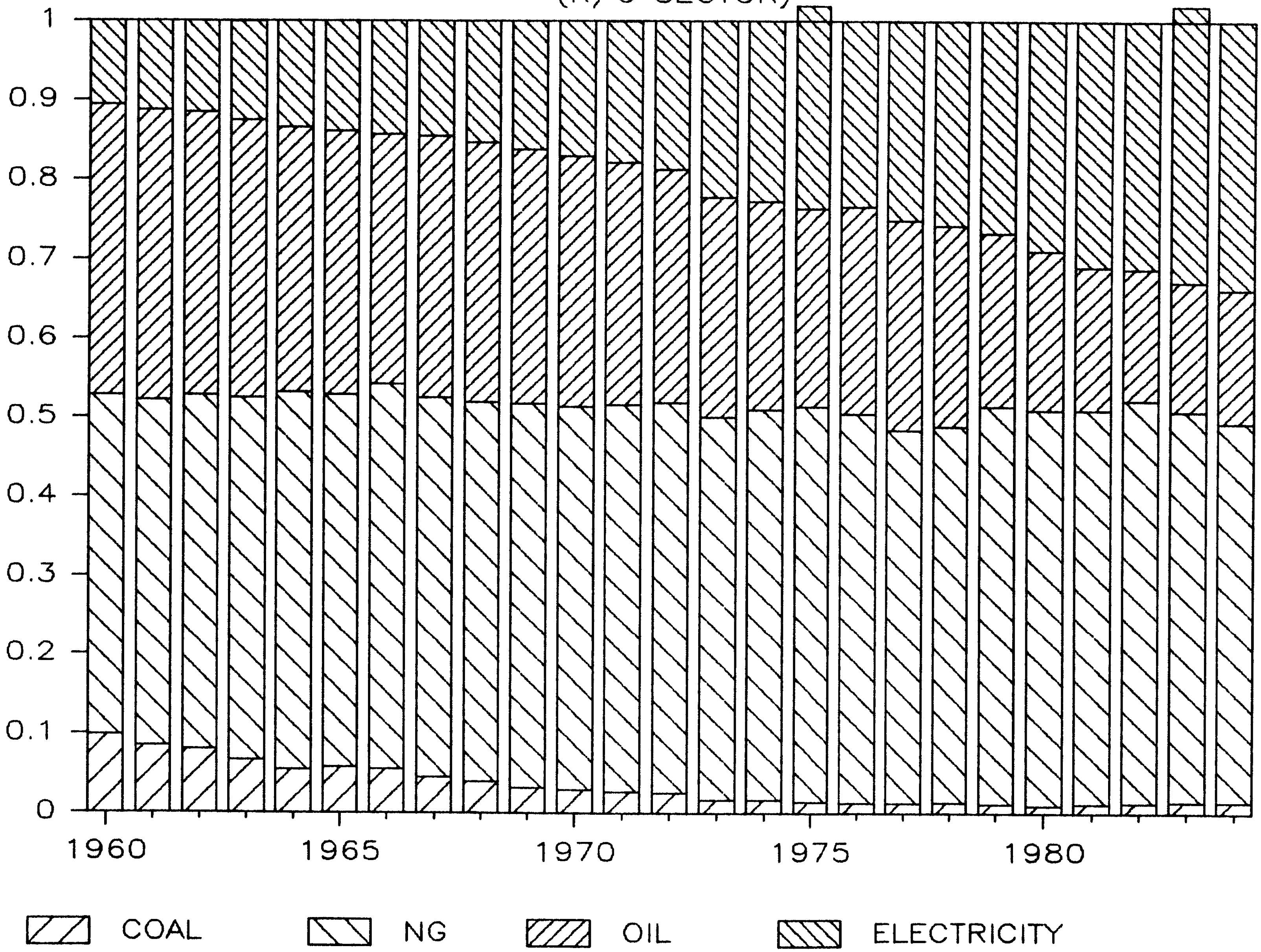
	Coal	Natural Gas	Petro-leum	Electric Sales	Total
1960	0.098	0.429	0.367	0.106	1.000
1961	0.085	0.437	0.365	0.113	1.000
1962	0.080	0.447	0.358	0.114	1.000
1963	0.067	0.459	0.350	0.125	1.000
1964	0.054	0.477	0.335	0.134	1.000
1965	0.058	0.471	0.332	0.139	1.000
1966	0.056	0.486	0.316	0.143	1.000
1967	0.045	0.479	0.331	0.145	1.000
1968	0.039	0.479	0.328	0.153	1.000
1969	0.032	0.485	0.321	0.162	1.000
1970	0.029	0.484	0.317	0.170	1.000
1971	0.027	0.489	0.306	0.178	1.000
1972	0.025	0.493	0.295	0.187	1.000
1973	0.016	0.484	0.278	0.222	1.000
1974	0.017	0.493	0.262	0.228	1.000
1975	0.014	0.499	0.251	0.237	1.000
1976	0.013	0.492	0.261	0.234	1.000
1977	0.013	0.471	0.266	0.250	1.000
1978	0.013	0.476	0.254	0.257	1.000
1979	0.012	0.502	0.220	0.266	1.000
1980	0.010	0.500	0.201	0.289	1.000
1981	0.012	0.498	0.181	0.309	1.000
1982	0.013	0.508	0.167	0.312	1.000
1983	0.014	0.494	0.163	0.329	1.000
1984	0.015	0.478	0.169	0.338	1.000

SOURCES: Federal Energy Administration, Project Independence Report, Nov. 1974; DOE/EIA, Monthly Energy Review, May 1982, January 1985.

FIGURE 1

US FUEL MARKET SHARE

(R/C SECTOR)



expanded gas sales is presented by large, price-sensitive customers. Some of these users experienced supply interruptions in the 1970s, and others switched from gas as prices rose in the late 1970s and early 1980s. Since these users have had unfavorable experiences with the uncertainties surrounding gas, both from policy intervention and from unresponsive pricing, a decision to use gas will be strongly discounted to offset these perceived problems. Decisions to return to gas use may be accompanied by demands for low prices, shorter contract terms to allow users to be "fuel opportunists," or other hedging devices.

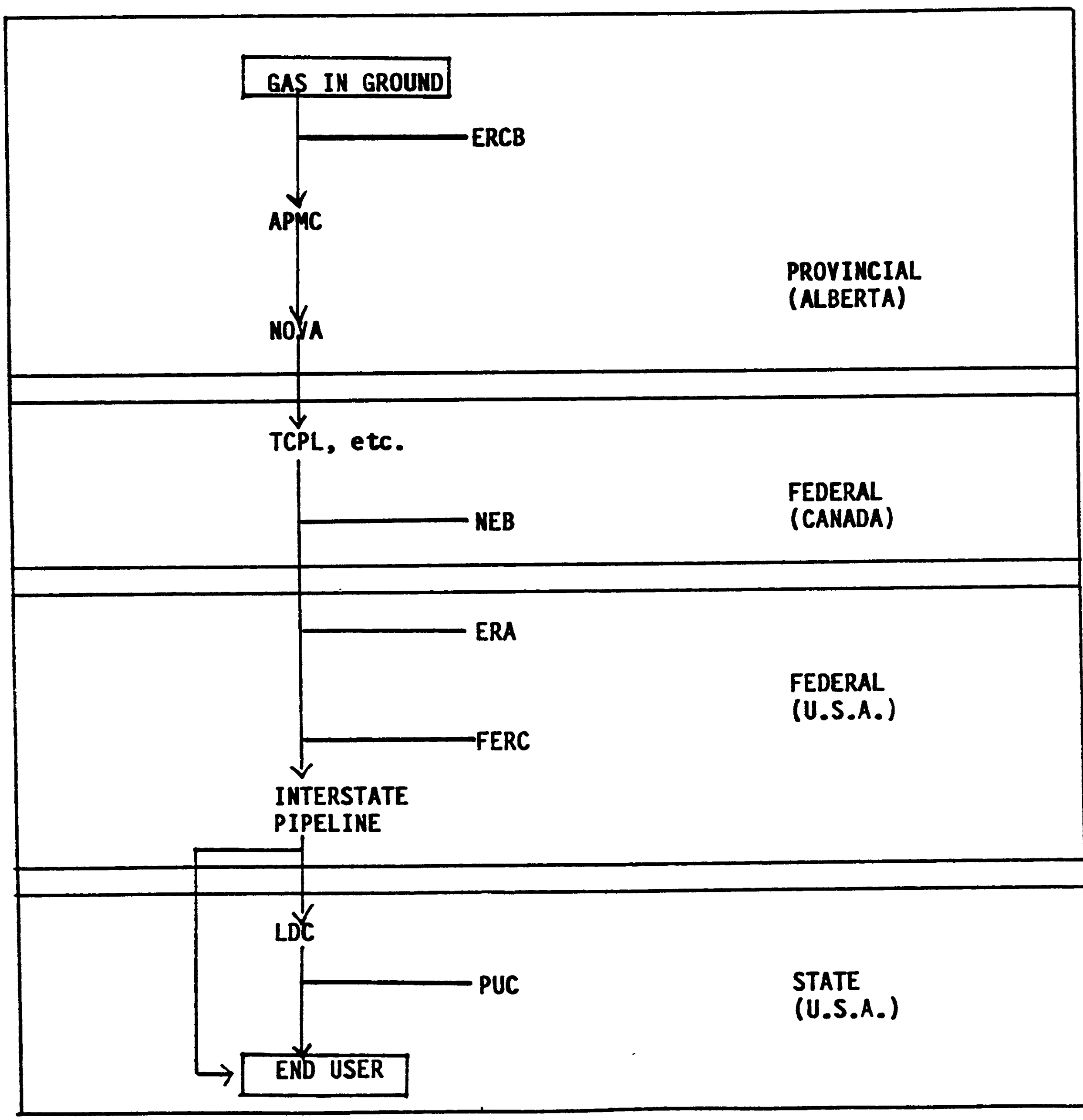
Whatever the strategy, there are certain steps that must be taken by anyone interested in selling natural gas, especially in the U.S. market. First, the gas must be available to be sold. Second, a way must be found to get the gas transported from the point of production to the buyer. Third, a set of regulatory approvals is likely to be required to actually consummate the sale and thus move the gas to the buyer. These three steps will provide the framework for our discussion of the current regulatory and policy environment in the market today. Figure 2 indicates both the physical movement of natural gas and the regulatory steps, which we will discuss in the following pages.

The question of gas availability is a nonissue in today's excess deliverability circumstances. Both U.S. and Canadian market-ready supply far exceeds reasonable expectations of early utilization at price levels with any resemblance to the past five years. For example, authorized Canadian export volumes are less than 50% utilized. Later, we will discuss how regulation on gas availability may in the future become a significant constraint on gas markets. For the immediate present, however, there is no binding constraint.

The second factor, finding a way to move gas to a buyer, is a slightly more complicated matter. Here, both the market structure and both countries' regulatory processes begin to play a role.

Figure 2

NATURAL GAS TRANSACTIONS AND MAJOR REGULATORY STEPS
(CANADIAN SALE TO UNITED STATES)



As noted earlier, U.S. market structure is one in which pipelines usually become the first purchasers of the gas, then resell it either to local distribution companies or directly to final users. Because pipelines were faced with differing opportunities, they have engaged in different contracting practices, some wise--some otherwise--each of them has a different average price of acquisition, which in turn affects the average weighted price they are able to offer to their customers. Because some pipelines have average gas purchase costs that are very high, they must offer a price for incremental supply well below their current average cost in order to secure new customers (or regain/retain them). Thus a gas seller with access to that pipeline may find the offering price unattractive. Other pipelines may have been astute in their purchasing practices, and so could afford to offer higher prices for incremental supplies--but may have little or no room in existing capacity.

Thus, potential sellers of gas may face structural problems in getting their gas to potential buyers in the United States, though it appears as though even a doubling of Canadian exports would not encounter actual, physical capacity constraints. This issue is examined in more detail in the supply portion of this study. While physical capacity may or may not be a problem, transportation regulation may be more of a problem.

The Federal Energy Regulatory Commission (FERC) sets the basic transportation rates for U.S. interstate pipelines through an application/hearing process by each pipeline. FERC considers several factors, but an attempt is made to encourage both competition and fulfillment of the obligation to serve the market(s) to which the gas is delivered. Contract terms come under scrutiny, including fixed (or demand) charges as well as commodity (gas cost) elements. Thus, FERC is a factor for sales in the U.S. market from both U.S. production and from imports. For example, FERC's order 380 excluded from minimum bill requirements all but incurred fixed costs for U.S. interstate pipelines. Though not specifying imports, the binding order on U.S. pipelines fed back through to Canadian export contracts. This order accelerated actions under way in Canada to end the uniform border price and the short-lived Volume Related Incentive Program (VRIP). The latter had been instituted to resuscitate export sales when U.S. pipeline purchases were reduced because the fixed U.S. $4.40/Mcf Canadian export price level was too high to market the gas in the U.S. market.

FERC has also played a role in dealing with the structural problem mentioned above where pipelines have an average gas cost that makes them noncompetitive, coupled with excess transportation capacity. FERC ruled that pipelines could have limited term authority to enter special marketing programs (SMPs). This allowed pipelines to approach gas sellers with a set of short-term delivered contract prices for a specific end-user; the pipeline then charged a transportation rate for carrying the gas. This arrangement helped cover the costs of unused capacity, while helping producers understand more clearly end-use market signals.

U.S. interstate pipelines sell much of their gas to local distribution companies (LDCs), which in turn sell to final users in the residential, commercial, electric utility and industrial sectors. Because distribution companies operate within single state boundaries, they are regulated by state regulatory commissions. Of course, federal regulatory actions on interstate pipelines feed through to the customers of the distribution company, but how such price and volume effects are allocated within the LDC is up to the state.

Until recently, state regulatory agencies were largely acquiescent in dealing with the consequences of federal actions. However, the successful Maryland Peoples Counsel suit against FERC-authorized SMPs may indicate a more activist potential, however infrequently exercised. Of course, California has always steered a unique course in the interventionist bent of its regulatory process.

Since the California market is important to U.S. and (especially) Canadian producers, the actions of that regulatory agency warrant separate mention. Indications are that the utility commission will remain opposed to special marketing programs by intrastate pipelines for industrial customers (including electric utilities). In part, the opposition derives from a rate structure that is "tilted" to favor residential users, and loads certain costs on industrial customers. Also, the commission sets industrial gas prices on the basis of low-sulfur fuel oil (the only competitive industrial fuel allowed due to high air quality standards). The resulting gas prices to industrial customers in California are among the highest in the United States. Not allowed to buy cheaper gas, industrial customers stay with fuel oil--or move to other states. Ironically, the only way around this paradox may be to bypass the CPUC by building a new interstate pipeline for private carriage to industrial and enhanced oil recovery customers. Thus, California represents very high market potential, but under existing regulatory trends there seems little likelihood that potential growth will be realized. (The potential California demand is analyzed elsewhere in this study.)

This example shows how state regulatory behavior can thwart gas sales. There is potential demand sensitive to price, pipeline capacity available to carry, and environmental rules that give longer-run stability to gas demand. However, with the current regulatory outlook (which seems to still be affected by a notion of gas shortage), the only way to sell incremental gas at lower prices necessary to cause fuel switching involves major capital expenditures for new pipelines.

Transportation of gas from producing provinces to eastern Canadian markets also has structural rigidities. The dominant (exclusive) carrier to eastern consuming provinces is TransCanada PipeLines (TCPL). Constructed to ensure Canadian use of Canadian resources, this pipeline system must move gas enormous distances before reaching a large customer base. High fixed and operating costs limit flexibility to transport for others (contract carriage) to eastern Canada at competitive rates.

The situation just described is additionally complicated by the fixed Alberta border price. An Alberta producer may find a buyer in eastern Canada, and pay a contract toll to TCPL. However, because the producer cannot reduce price at the Alberta border, no price incentive is possible. Similarly, TCPL's toll methodology places a demand charge on distributors for service that is rather insensitive to volume. Thus, an industrial user who approaches TCPL for transportation may be thwarted by the distribution company's unwillingness to be the final transport unit to the plant, since the distributor has lost load but still must pay TCPL the same toll.

This same perplexity will likely reduce the possibility of U.S. gas again moving into Canada. Eastern Canadian distributors have a strong incentive to stay with the TCPL "package" of gas and transport. Prices would have to be very low and volume increase great to offset the continuation of these demand charges on a smaller take from TCPL.

In summary, a combination of structural and regulatory matters complicate finding a way to transport gas from the point of production to the site of use--our second problem.

The third task in making a sale--obtaining various regulatory clearances--is potentially the most complicated, and provides the richest set of examples about how gas markets in the future may be jeopardized.

U.S. producers do not now require any regulatory approval to make a sale. Their task is either to find a pipeline willing to buy the gas at an attractive price, or to find an end-user who wants to buy and then get a pipeline to transport it for a fee. The only regulatory clearance is that which the pipeline (if interstate) may need from FERC, but even that is likely to be a generic ruling rather than one for the specific sale.

The Canadian situation is very different, and though some processes have been referred to previously, a review of the regulatory steps will show the complexity. Alberta will again serve as our example.

If a marketable gas discovery is made, any potential sale must be reviewed by the Energy Resources Conservation Board (ERCB), even if the sale is within Alberta. The ERCB review, which includes conservation, "public interest," and safety practices, is particularly concerned with a 25-year reserve test for removals from the province. This review covers both known reserves and the "trend" of additions (referred to earlier), and includes both Alberta gas requirements and productive capacity. If such requirements are met, then the ERCB issues a removal permit, which is in effect a production license.

If the proposed sale is within Alberta, then transportation must be arranged through NOVA, an Alberta Corporation. NOVA is the franchise transporter of gas within the Alberta border (to distribution companies and large end users), and delivers gas to export points at the borders. While no regulatory approval is required for NOVA carriage, disputes over its tariffs for carriage are resolved by the Public Utilities Board (PUB) through a hearing/decision process. The PUB does not currently set prices for sales within Alberta, though it has the authority to do so, if so directed by the Alberta government.

Contract terms are not subject to review for intra-Alberta sales, but a maximum price is set by the Alberta Petroleum Marketing Commission (APMC). This price formula is the Alberta border price (to which we will refer later) less a cost of service factor which is deemed to be those costs incurred within Alberta to get gas to the border. Producers may negotiate with intraprovincial distributors or other direct sale customers for a lower price, and indications are that almost 50% of such sales are below the price maximum--frequently far below. The reason for such discounting is obvious: without export market opportunities, producers have no real competitive outlets. This will be analyzed in greater detail later when we examine future policy options.

If the potential sale is for export from Alberta (whether to elsewhere in Canada or internationally), then the ERCB also determines if there is an "exportable surplus." The 25-year reserve test mentioned above is used, though we now understand that low gas prices in the de facto captive Alberta market have probably stimulated consumption, and discouraged development and reserve additions. These effects in turn feed back into the 25-year reserve test, which could over time become a binding constraint on exports from Alberta. Because of the low prices, additions to reserves will decline, and there will be an apparent shortage; the shortage will be only at those price levels.

Currently, there is no doubt about the exportable surplus, so the next step is sale of the gas. However, that sale is not to the customer (usually an exporting pipeline at the Alberta border, but also occasionally to an end user), but to the APMC. Because nearly 90% of gas production is from provincially owned mineral rights ("Crown lands"), the APMC functions as the province's royalty collection agency. Depending on geology, the royalties vary between 25 and 40%, and are frequently taken as production shares. The APMC resells the gas to an exporting pipeline and directs the royalty share into the provincial treasury. The price at the border is set under agreements negotiated with the federal government and thus not fully within provincial discretion. (It must be remembered that sales elsewhere in Canada require substantial transportation costs that the final user must pay. We will refer to the pipeline marketing role again later.)

If the gas were destined for sale outside Canada, the price would be higher than the APMC border price for interprovincial sales, and this sum was also collected by the AMPC for payment into a "flow-back" fund. Because these revenues are derived from an export price wedge, current Alberta policy disburses these funds to all provincial gas producers whether or not they are selling gas anywhere outside Alberta. The outbreak of competitive markets drove down the price differential between Canadian and U.S. sales, so the flow-back margin recently has dropped from in excess of $C1.00 to less than $0.20 per Mcf. The effects of this policy on incentives to market and on experience in marketing will be taken up later.

If the gas is destined for interprovincial Canadian markets, the transaction could now proceed, though it almost certainly would be a sale to TransCanada PipeLines.

However, if the proposed sale were to be an export from Canada, there are additional regulatory steps that must be taken. The first hurdle is Canadian, and then the U.S. process begins.

The Canadian step involves securing an export license or order from the NEB. Traditionally, the most important issue considered by the NEB has been its version of the exportable surplus test. (Recall that NEB would not be considering an application that had not already received an Alberta removal permit.) The NEB surplus test is made up of two parts (here greatly simplified): (1) a 25-year multiple of the current year Canadian demand, compared to current total proved reserves; and (2) a deliverability assessment that judges the gas system capacity to meet domestic and export obligations in the reasonably foreseeable future.

A new set of criteria was added to this surplus test in November 1984, when export pricing policy changed. Prior to this date, a uniform border price was in effect ($4.40/Mcf) adjusted only by the previously mentioned Volume Related Incentive Price program, which offered a discount to $3.40/Mcf for volumes equal to the lower of 50% of annual contract, or 1981-82 actual sales. The new export criteria may be summarized as follows:

1. The price must recover its share of incurred costs;
2. The price will not be less than that of the wholesale price at the Toronto City Gate under similar terms and conditions;
3. The price in the final U.S. market area must be at least equal to competing fuels;
4. Export contracts must be renegotiable to reflect market changes over the term of the contract;
5. Assurance must be given that contracted volumes will be taken;
6. Producers must endorse current and future terms of export contract; and
7. If a new contract is a renegotiation of a current contract, the exporter must demonstrate that the economic return to Canada is enhanced.

Though these elements indicate some movement away from a rigid border price, the Toronto City Gate restriction means it is far short of market-oriented pricing. These criteria do, however, represent a remarkable turnaround in Canadian regulatory perspective. When we later take up a discussion of future prospects, we will examine these criteria in more detail.

After this NEB review, the gas seller is free to remove the gas from Canada. However, in order for the gas to be imported into the United States, approval must first be secured from the Economic Regulatory Administration (ERA) of the U.S. Department of Energy. In the past year and a half, imports from Canada have received not only routine, but even expedited approvals. ERA's criteria for such approval are quite general, needing to be satisfied that the import is reasonably (competitively) priced and that the gas import supply is secure enough to be in the national interest. The ERA also approves gas exports from the United States, though there has been little call on that judgment in recent years. (It is an intereting question what role the ERA might have in future decisions to export Alaskan natural gas as LNG, to Asia or elsewhere.)

Finally, assuming ERA approval is secured, then the contract can be executed and the gas delivered into the U.S. market. The one exception would be if the delivery required new pipeline facilities in the United States. In that event, FERC approval of inclusion of the pipeline costs in the U.S. interstate pipeline's rate base must be secured. This point has relevance to certain Canadian sales options including the Venture field off Nova Scotia (discussed in more detail elsewhere in this study), Can-Am and NIPS. All these would require new U.S. facilities, and thus would come under FERC review.

All the foregoing has used a hypothetical Alberta seller. British Columbia also exports gas to the U.S. market, and thus is subject to the federal Canadian and U.S. regulatory regimes just described. The regulatory framework in British Columbia is similar to Alberta in practice, though the specifics differ. In general, the British Columia Petroleum Corporation functions in a similar way to the APMC, and the Ministry of Energy, Mines and Petroleum Resources has similar responsibilities to the ERCB plus AENR. The major difference is that Westcoast Transmission Company (WCT) has a monopoly on export transportation, though it functions in close concert with British Columbia policy. For example, WCT is an equity partner in the proposed Canadian LNG export project, and will manage incremental pipeline transportation facilities if that project goes ahead.

This then concludes our review of the three steps needed for a U.S. or Canadian seller to deliver natural gas to a customer. The recurrent miracle is that gas actually does flow through this thicket of institutional and regulatory barriers. The importance of change in the future is now addressed.

The Future: Costs and Benefits of Change

In another part of this project we indicate that a considerable amount of gas can be produced at low costs, especially in Canada. In the demand analysis, market prospects are identified, with some indication of the prices that would claim them. These are the obvious ingredients for a market both to exist and to grow. Unfortunately, it is not certain that the obvious will occur.

The foregoing pages have identified those policy and regulatory interventions that contributed to the rather ungainly structure that we call the North American natural gas market. Both past practice and current policy obstruct opportunities for positive gains. Unused production and transportation capacity lie fallow; potential markets go unserved while currently glutted markets are eagerly sought; real demand near producing regions is ignored while uncertain demand in distant potential markets is competed for; producible economic reserves lie unused while marginal new reserves are considered for subsidy.

For most economic decisions, present value benefits are a central consideration in deciding among alternatives. A comprehensive, integrated application of this approach seems somewhat alien in the natural gas industry, either by the participants or those whose policy decisions fundamentally affect industry actors. This is not to say the motives of policymakers are malicious--indeed, these are largely persons of good character placed in impossible decision-making situations where the outcome of their actions will only create a new set of distortions. These distortions will offend as many as are pleased.

Nor would we suggest that gas industry actors are incapable of participating in a real market, where gas must be actively sold and price, volume and other conditions negotiated without any real knowledge about future interfuel competitive developments. It is just that these participants have had so little opportunity to do those sorts of things which are so familiar in other competitive markets. Living in a regulated market did not breed these capabilities.

Any recollection or analysis of U.S. and Canadian policy actions over the past decade must identify one central perception that shaped these policies: that the world is facing an imminent shortage of energy, especially natural gas, and that future prices will certain rise. The corollary to this perception is that whatever resource base one's own nation has should be reserved for itself first, and only irrefutable surpluses be sold elsewhere (preferably at a price far above that fetched at home). In a policy environment driven by such an outlook, it is no wonder that discounted present value is a somewhat alien concept.

Yet, we would suggest that governments, as well as private sector participants, would do well to examine policies from an economic perspective. The small model we have assembled for this project provides some sense of the value of revenue streams at different points in time. While it does consider the resource base, it makes no prejudgment about scarcity except as a function of cost/price interactions. Our calculations are simple and our data heroic in both extent and detail, but that seemed best in order to make the sense of the analysis accessible to others.

As background for some of the issues for which this model and its analytic approach might be useful, we now turn to a set of policies (or policy processes) that are likely to be barriers to development of economic international natural gas trade in North America. No priority of wrong-headedness is implied by the order in which these are taken, nor is national preference intended. We simply follow gas from its reservoir to end-users.

BARRIERS TO CHANGE

1. Provincial 25-Year Reserve Tests. Born of the fear-of-scarcity era, this substitutes policy judgment for market incentives. Worse, it creates a pool of reserves that removes incentives to drill, develop and market gas. This may be especially damaging to small producers, and acts as a barrier to new entrants.

It also has the effect of increasing carrying costs, thus making locally producible, but nonexportable gas susceptible to distress sales within the province. While this is certainly bad for producers, it also creates the wrong signals for local gas consumers who risk dependency on this *de facto* subsidy by regulation.

While such a reserve test may have had a rational at one time for both the province and federal levels (to provide a supply inventory for pipeline finance, a requirement no longer necessary), the costs of carrying this inventory are now a burden for all.

2. Single Provincial Border Price. This practice is a relic of the single export price of times gone by. Its benefits are doubtful; its effects may even be perverse--especially with the flow-back feature which removed strong initiative to market gas. Because gas must compete with different fuels in different markets at different transportation distances from production, there is no such thing as a single gas price. Nurturing this fiction will cause

present value opportunities to be lost first--then whole markets could wither. The only use for this concept now seems to be administrative convenience to calculate royalties or other taxes. These seem unimportant when balanced against the potential adverse effects.

Realities of the future dictate that the concept of net-back price guarantees will not hold up. Some companies will not respond and will not survive the competition. But to cling to the concept will court disaster for the industry.

3. Single Federal Export Price. Though this now seems to be under critical review, its continuation has all of the ill effects cited above. Its identification as the "Toronto City Gate price" does not change its impact. Indeed such a basis only exacerbates federal/provincial and interprovincial tensions, which already complicate good policymaking far too much.

4. NEB 25-Year Reserve Test. Again this policy has all of the problems noted with the provincial concept, plus some others. Because it accumulates the drilling disincentives for every potential producing province, it runs the risk of a "guillotine" effect by falling with little warning on whatever unlucky applicant is there at the time of triggering.

In addition, interaction with a single toll rate for transport to Ontario and Quebec (also an NEB decision) makes flexible pricing for gas in those provinces almost impossible. The toll's insensitivity to market competitive prices is an effective barrier against U.S. gas entry or western Canadian production moving through a cheaper U.S. transportation routing. Distribution companies have little incentive to find cheaper gas if the toll charge on the more expensive gas does not diminish with smaller volume.

5. Take or Pay Backlogs. Though not directly a result of regulatory action, a major barrier to sales is the large backlog of gas contracted for but

not marketed. Estimates indicate that approximately 8 TCF of Western Canadian gas is in this category, and nearly one-quarter of this is under contract to TransCanada PipeLines. For producers with gas not covered under these contracts, this inventory backlog presents two problems. First, the pipelines and marketers who contracted for the gas will work off the old inventory before contracting for new gas, and this means the pipelines will resist price cutting that may be necessary to enter new markets. This in turn leads to the second problem, which is the disincentive to producers to develop and sell gas into the changed U.S. market.

Finding a solution to the backlog problem is not easy, especially since financial institutions have been involved in bridge financing to resolve TCPL's take-or-pay problems.[8] However, because gas markets will likely be glutted for some years, short-term sales of this backlog at lower prices is obviously in order. The SMPs in the United States showed that gas could regain markets if pricing were responsive to interfuel competition. Absent such action in Canada, exports may seriously lag behind potential. NEB might examine a blanket relaxation of export criteria for this backlog, and allow short-term sales to be consummated--if the gas came from take-or-pay backlogs. Otherwise, this situation may distort incentives and policy decisions for several more years.

6. ERA Criteria for Canadian Imports. ERA actions thus far have been exemplary and appear to give priority to the assumption that contracting parties know what risks are involved in the transaction. Thus, ERA approval is quick and apparently reliable.

Unfortunately, the ERA is implementing laws framed during U.S. fear-of-scarcity days, and therefore is susceptible to changes in attitudes.

[8] One study felt the TCPL problem was sufficiently severe that consideration should be given to splitting the company into a resource owner and a "contract carrier" transport company. See Connections, An Energy Strategy for the Future, Economic Council of Canada, Ottawa, Canada, 1985, pp. 66-68.

This is especially crucial in assessing one criteria, "Need for the Natural Gas." The current interpretation follows:

> The need for the imported gas will be addressed in terms of the marketability of the proposed import. Need for a gas supply is intrinsically related to its anticipated marketability. Thus if the imported gas is competitive in the proposed market area and, though its contract terms will remain competitive throughout the contract period, then the rebuttable presumption exists that the gas is needed in that market.[9]

This interpretation is as close to letting markets operate as any regulatory agency can make. However, if U.S. producers begin to be threatened by competitively priced Canadian supplies, this approval point could come under considerable pressure.

7. <u>FERC Actions to Protect U.S. Pipelines</u>. While realizing there is need for some adjustment period for pipelines emerging from an era of overcontrol, old habits are the hardest to quit. The experience of recent years indicates that the gas market was not prepared for the outbreak of competition. This lack of experience is being rectified, but not everyone will succeed in the new environment--and this includes some pipelines, at least configured as we know them. The recent mergers and acquisitions are likely to be only the beginning of a restructuring of this industry to deal with an entirely new competitive environment.

New rules regarding pipeline transportation are in the offing, and indications are toward a more competitive environment. A shift toward contract carriage is perceptible in the pipeline industry, and is being encouraged by the trend of new regulations. While the lingering uneven distribution among pipelines of old gas contracts remains a serious problem, new carriage arrangements will offer creative opportunities for gas marketing.

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[9] <u>New Policy Guidelines and Delegation Orders on the Regulation of Imported Natural Gas</u>, Economic Regulatory Administration, DOE, February 1984.

The FERC Commissioners do appear inclined toward encouraging competition and recognizing that risk in the gas transport industry cannot be avoided through regulation.

8. Canadian Royalty and Taxation Management. We have not discussed this matter previously, but it has relevance and importance to gas trade. Most current royalty and taxation regimes were established when prices were rising, and that trajectory looked as if it would continue for a long time. Arguably, 10 years is a long time, but that time is over.

It may well be that for Canadian gas to be competitive in international markets, some adjustment in fiscal regimes will be necessary. Unfortunately, revenue dependency has been built around these royalties and taxes. But the reality is that if Canadian gas is not competitive in the United States, in Asia, or even in eastern Canada, then it will not be sold. If the gas is not sold, there is no transaction for royalty or tax to be levied against.

Thus, Canadian policy making must decide if they prefer some smaller take of revenues on a large set of transactions but getting that take sooner, or if they prefer a large share of a smaller volume. The model in this project allows alternative calculations to be made in this regard, and we believe it important that alternative fiscal regimes be considered as serious possibilities--and that includes conventional gas, as well as frontier areas such as the Venture field.

9. New Ways of Contracting. This is not a specific policy item in either country, but contract reviews are woven throughout regulatory processes. In fact, contracts are sometimes slanted toward a regulatory bias that is known to exist.

In a world of greater competition, contracts will increasingly be used to allocate risks of all sorts. Contracts will have to adapt to less regulation (which protected some against risk), and are likely to be substantially different in both structure and even duration. Financial institutions will have to take more risk, as will producers, transporters, distributors and end-users. The future is simply riskier than it was.

But one of the greatest risks is that regulators and policymakers will be slow to recognize the need for new types of contracts and thus will add still another risk--discouragement of these necessary new arrangements.

This, then, concludes our examination of policy issues and processes that appear to be crucial to the development of more competitive North American natural gas markets. It is clear that waiting for the good old days to reappear is fruitless. Not only are gas markets competitive in themseleves, but gas is also locked in combat with two other significant contestants: (1) other fuels for existing facilities (including increasing ability for fuel switching); and (2) capital investment, that will not only make a long-lived fuel choice, but also will use less of whatever fuel is chosen.

These competitive realities cannot be denied, and to ignore them is a perilous course. Policymakers in both the public and private sector must realign their perspectives and their actions.

A Concluding Reflection

Any international transaction necessarily entangles at least two national governments, plus important variances of culture, language, custom and business practices between and even within each of the nations. In studying international natural gas trade, we give almost exclusive focus to economic market forces, and by definition therefore pay little attention to the differences just cited above. We hope that our single-mindedness makes a basic contribution to mutual understanding of the fundamental economic forces at work. Our detachment is intentional, and is meant to be beneficial.

In analyzing policy actions, heavy emphasis has been given to Canadian alternatives. This is not because we think their past decisions have been more deficient than those in the United States. Instead, we believe Canada has opportunities for action that are simply not possible in the United States. In the U.S. form of government, policy is an accretionary process built up by laws and their implementing regulations. Change of a basic sort requires changing fundamental law, and thus must undergo Congressional action--a process that makes both timing and outcome vastly uncertain. The Canadian system permits the majority government to put its program in place, and to change it if the political climate permits. We do not suggest policy changes are simple, easy, or without the need for consultation and compromise. But in a real sense, Canada can affect its future directly as a result of the decisions it takes. Indeed, current U.S. regulatory, legislative, and policy formulation shows room for improvement. There is a need to deal with the natural gas utilization prohibition in new electric generation facilities. If gas can compete in price and supply terms, then it should be given that chance. Cogeneration is an interesting prospect that may be of real economic interest to certain users in certain locations; however, the implicit subsidy in PURPA simply distorts investment decisions and creates cogeneration facilities that would not otherwise be built. Of course, changing political fashion in state regulatory agencies will be difficult to predict, but one hopes they will encourage new forms of marketing programs, price discrimination, or expansion of competition through new suppliers. FERC seems to be moving toward encouragement of competition among interstate pipelines, and it is hoped that this direction will continue.

The size of the U.S. natural gas market is so large that it represents a major sales opportunity for Canadian sellers. Over one-third of Canadian production now goes to the U.S. market. Because demand in eastern Canadian provinces is fairly stable, the incremental market for western Canadian production is the United States. While it could be (and has been) argued that Canada is in a price-setting position for U.S. incremental demand, our analysis indicates that a price limit is set by interfuel competition in the industrial and utility boiler market, and/or capital investment in energy-using equipment for alternative fuels (especially coal). Thus Canadian rent-taking opportunities exist principally below these alternative fuel price levels.

For the reasons stated above, Canadian decision makers should pay particular attention to gains that may be possible by competing strongly for large volume sales to U.S. industrial and electric utility customers. Since Canada currently has a supply cost advantage, such a course of action is both feasible and potentially profitable.

Of course, it could be argued (and frequently has been) that a better strategy is to wait until the U.S. excess deliverability is dissipated, then sell at the higher prices which would result from U.S. supply shortfalls. There are two risks with which this strategy must deal. First, there is considerable uncertainty about how long it will be for such a prospect to materialize. Even at a low discount rate (say, 10% real), a delay of ten years would require sales in the mid-1990s that yield revenues over 150% higher than currently may be available. This would be necessary to gain the present value benefits forfeited by waiting, and brings us to the second risk. If supply is constrained and prices appear likely to increase, U.S. industrial and electric utility markets will switch to other fuels again. Thus, there is a risk that neither volume opportunities nor price levels can be combined in the future to offset the value of revenue foregone by not competing strongly in the market today.

In view of the above risks, it would seem advantageous for Canada to engage this market opportunity. It therefore follows that both provincial and federal interests would be best served by removing current policy barriers that prevent such opportunities from being realized. It also follows that U.S. policy and regulation should give both permission and encouragement to such market developments.

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SUPPLY ASPECTS OF NORTH AMERICAN GAS TRADE

by

M.A. Adelman and Michael C. Lynch

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with the assistance of Kenichi Ohashi

"Many Soviet planners were not convinced that such a valuable nonrenewable resource as gas should be sold to the capitalists."[1]

SUMMARY

The supply of U. S. natural gas, from the producing industry's perspective, **appears** to be stable. The price has changed little in the past three years, and may be declining in real terms. At the current price level, which is much higher than in the past, reserves are being maintained, with gross reserve additions about equal to production. Falling factor costs and increased efficiency suggest that supplies will continue to be adequate through the end of the decade, and the high level of drilling activity indicates that, even in the current weak market, natural gas discovery, development and production remains profitable. But data are lacking to indicate whether this can long continue, or whether real production costs must turn strongly upward, bringing prices up with them--unless there are substantially higher imports from Canada. If the U.S. industry has overshot downward the long-run supply curve, due to the current glut of drilling rigs, etc., then domestic supplies may tighten in the next decade.

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[1] Thane Gustafson, **Soviet Negotiating Strategy: the East-West Pipeline Deal, 1980-84** (Rand Corp. R-3220, February 1985).

However, Canadian imports could displace substantial U. S. production, because Canadian gas is generally cheaper. Moreover, increased output would, within limits, probably lower Canadian development and operating costs.

By the criteria of relative cost, the Venture field is marginal at best. More expensive production, e.g., in the Northwest Territories, cannot be sold in the United States for years, even if world crude oil prices rise. But the prediction of rising oil prices is itself debatable.

At current prices, then, we see adequate supplies for some time to come. Lower prices, due to falling oil prices, could see some reduction in U.S. supplies, after a lag time of several years, and an increase in Canadian exports, if the government will allow it. If not, then a loss of market share to oil would occur.

INTRODUCTION

Our analysis deals with the prospects of larger Canadian natural gas exports to the United States. Yet both Canada and the United States appear to have a gas surplus at this moment, which would mean: no scope for trade. We believe that this appearance is somewhat deceptive.

Stability in the U. S. Market. In the United States, as one oilman recently put it, we are in the fifth year of an 18-month gas "bubble." In fact, the market has been stable, something not seen for decades. Since about 1982, the highest allowed **contract** price for "new" (but not "new new") gas has been \$3.27 per Mcf, but with no actual contracts being written, which suggests that the market-clearing price on term contracts would be something like \$3.

A short-term, usually mislabeled "spot", market has emerged, and since late 1983 the "spot" price has, after a period of stability, fallen to the neighborhood of $2.10 in October 1985.[2] The spot prices published by the U.S. Natural Gas Clearinghouse include transactions under contracts between one and six months.

The "spot" price is usually downgraded, as being of only momentary significance, and related only to bare operating costs, not the return on needed investment. This is mistaken. The owner of a gas reserve knows that the unit sold today cannot be sold tomorrow. Therefore, he will not sell it off for less than the total of operating cost **plus** the present value of (a) the expected future net profit, or (b) the expected future cost of finding and developing an additional unit. The lesser of (a) or (b) is the opportunity cost of selling off the unit today.

Therefore, even a short-term price reflects the total cost of replacing reserves. But the shorter the contract term, the less is the effect. Figure 1 shows the relation between the term of the contract and its departure from the long-term price.

If a price is really "spot", i.e., an isolated transaction today, it may depart widely from the long-term equilibrium price. But we would expect it to fluctuate both ways. A price which extends over several months, and does not change much, is an indication that the long run supply price cannot be very much higher than the recent average.

If we suppose that the long-run supply price is around $3 and the discount rate is 10 percent, then a price of $2.60 is consistent with an

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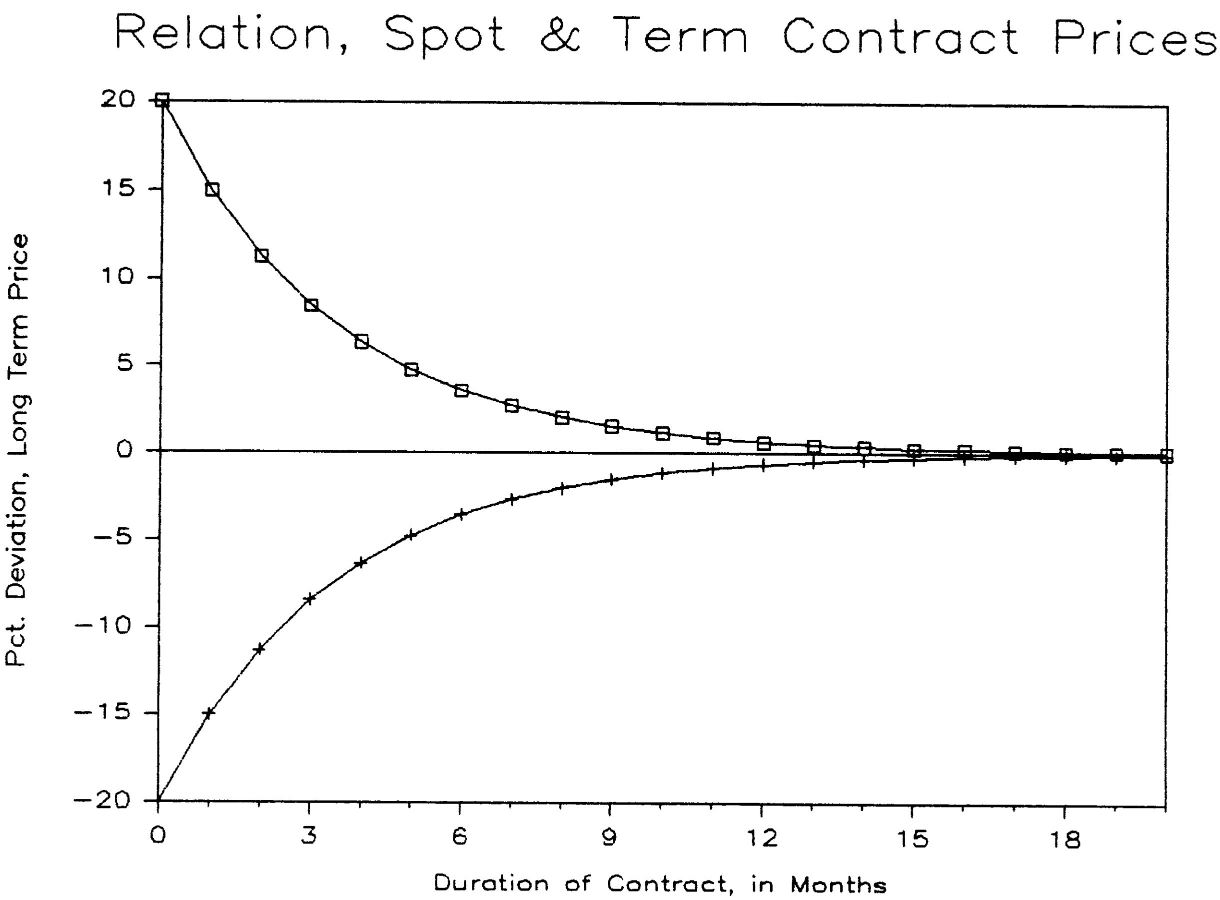
[2]The source is the Natural Gas Clearinghous, cited in **Oil & Gas Journal**, 10/21/85, p. 25.

Figure 1



Relation, Spot & Term Contract Prices
20
15
10
5
0
-5
-10
-15
-20
Pct. Deviation, Long Term Price
0
3
6
9
12
15
18
Duration of Contract, in Months

implicit prediction that if not sold today the asset would have to be held for 18 months. (That is, $\$2.60 \times (1.1)^{1.5} = \$3.00$.) A lower spot price implies a shorter waiting period, a higher discount rate, or a lower long-run supply price.

Getting accustomed to stability. Stability has caught the U.S. gas market by surprise. For about 30 years, the actors in the U.S. gas market have grown up and been schooled by an atmosphere of **shortage**. Gas prices at the burner tip have been constrained, by rate-of-return regulation, below market clearing levels, creating a built-in shortage. Since the mid-1950s, field prices have also been constrained.

At every stage, more gas could always be sold, at higher than current prices, if only the regulatory authority would permit it. And of course the oil price explosions boosted the demand for gas while general inflation raised costs. Pre-NGPA price ceilings became an even more powerful disincentive to discovery and development of additional reserves. Thus the perceived shortage fed upon itself. The mythical "energy crisis" and the belief in \$100/barrel oil strengthened the belief that gas was permanently scarce.

Higher prices have reduced demand and increased supply to create at least a momentary balance. The question for our purposes is: Where does the market go from here, and will larger Canadian exports be a factor in it?

There is no question of a large surplus of **capacity to deliver** in the United States, but it is not clear how much of a surplus of **producing** capacity there is.[3] A canvas in Texas during 1982-83 proved, if nothing else, that statistics relied upon might be right in a qualitative sense, but had no precision. More importantly, there seems to be no overhang of gas reserves that it would pay to deplete immediately. The question, indeed, is whether the stock of reserves can even be maintained at the current price for new gas. If not, there will be a real long-term shortage, in the sense of the long-run supply price to maintain the reserves being above the current price for new gas.

The statistics on U.S. natural gas reserves are consistent with temporary stability, but do not furnish much of a clue as to the longer term.

Table 1 excludes Alaska. The great bulk of its gas "reserves" consists of the gas cap at Prudhoe Bay, which is not a developed reserve. It may or may not be developed in the future. As far as the U.S. market is concerned, Alaska should really be considered as an outlying part of the Canadian Northwest, with the attendant transportation costs.

Total end-1983 reserves were 166 Tcf, the same as end-1980. Since production has decreased, the depletion rate has decreased. But the reduction has resulted from the sharp rise in gas prices up to late 1982. It may be too recent to draw any conclusions, but so far, at least, the higher prices have not elicited more supply. The **gross additions to non-associated reserves** record the response of investment to higher gas prices. Additions to associated-dissolved gas record chiefly the response to oil prices.

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[3]**Natural Gas Monthly**, DOE, 7/85, p. 14, estimates that 1.7 Tcf of surplus gas is available for the second half of 1985, although this includes some double-counting. The American Gas Association puts excess productive capacity at 2.9 Tcf/yr. in 1985, down from 3.2 Tcf/yr. in 1984. See **Oil & Gas Journal**, 9/2/85, p. NL 2.

TABLE 1. SALIENT STATISTICS OF NATURAL GAS SUPPLY
(Trillion cubic feet)

A. U.S.: excluding Alaska

Year	Proved Reserves (Year-end)	Production	P/R	Gross Reserve-additions	
				Total	NonAssociated
1977	175.2	18.8	0.107	13.2	9.5
1978	176.0	18.8	0.107	19.6	12.3
1979	168.7	19.2	0.114	11.5	11.6
1980	165.6	18.7	0.113	16.1	11.4
1981	168.7	18.7	0.111	21.8	19.9
1982	166.5	17.5	0.105	16.5	14.3
1983	165.9	15.8	0.095	16.9	13.4
1984				17.5	

SOURCES: DOE/EIA, U. S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 1981-1983.
1984 reserve additions estimated by AGA.

B. CANADA

Year	Established Reserves (Year-end)	Production	P/R	Gross Reserve Additions
1977	76	2.5	0.032	4.8
1978	79	2.3	0.030	4.8
1979	82	2.6	0.032	5.6
1980	88	2.5	0.028	8.8
1981	88	2.4	0.027	2.3
1982	90	2.5	0.027	4.9
1983	91	2.2	0.024	3.4

Source: Canadian Petroleum Association, Statistical Handbook. Note that "Established" Reserves are about 30% higher than "Proved" Reserves.

Non-associated reserve additions have fluctuated too much to establish a trend. At best, they seem a little higher after 1980 than earlier.

An optimistic interpretation is that the stability in non-associated reserve additions has come about despite the very high level of real interest rates, which mandates lower inventories of all kinds. Putting this aside, we have to admit that we do not know whether the stability in reserves, and the lesser pressure on the producing industry, is lasting or not.

Assume that reserves-added will shrink. Then either prices must rise or there must be larger imports of Canadian gas. Assume, contrariwise, that reserves-added will be stable. Then Canadian gas can flow in at prices somewhat lower than today's. If private parties are left free to make the best bargains they can, the price level depends on: Canadian costs compared with United States, on the total increment to supply, and on the elasticity of demand.

On both sides of the border, gas producers must make decisions about how much to produce and when.

The optimal depletion rate. The basic supply problem is: What rate of depletion of gas deposits is optimal? There is an obvious major difference between the two countries: The U. S. average depletion rate is around 10 percent; the Canadian rate less than a third of this. We show below that this indicates great potential for profitable expansion in Canada, providing there is a U.S. market at prevailing prices. But the question remains whether Canadian interests are served by faster depletion.

In the United States, the individual owner makes the depletion decision, subject to the constraints of supply price, market price, and government.

In Canada, at least for export shipments, the provincial and national governments must permit output to be expanded, and will only do so if they judge that an interpretation of a collective interest is being served. However, they face the same problems.

Consider an Mcf of natural gas that could have been sold in 1981 for US$4.94. Had it been sold, and the proceeds invested in riskless securities, it would today be worth approximately $7.50. But the gas can be sold today for no more than about $3. Hence the loss of value of the asset has been 60 percent. Even if the gas had been sold as incremental quantities for only $3/Mcf in 1981, the value today would be $4.51. The loss in value versus a $3 sale today would still be one third. If the example were more realistic, by subtracting incremental costs, the result would be even more dramatic.

This does not prove that the decision to withhold gas was wrong. Perhaps the price of gas may rise in the future. The real question is whether the price of gas can ever rise high enough, soon enough, to have made it worth holding back in 1981. It seems unlikely.

By the same token, anyone who thinks it is right for Canada to sell off gas today at US$3 (or less) must believe the price will never rise high and fast enough to make it worth holding back.

Obviously, a decision depends on the expected price trajectory of natural gas, and on the rate at which future receipts must be discounted. The example of the 60 percent loss on gas withheld in 1981 proves only one limited proposition: **Natural gas in the ground is a risky asset.** We need to ask why this risk exists. Then, with some specific measure of risk in hand, we can talk about the wisdom of a specific decision.

The nature of mineral price risk To regard natural gas as risky runs counter to the assumption, which was stated in the National Energy Program of 1980 (but is held even when it is not stated), that oil and gas prices must keep rising, except for some temporary limited interruptions. As we noted above, many in the Soviet Union hold this opinion, and there is probably not a single mineral- exporting nation in which this sentiment is not echoed. The reason for this deep-rooted belief is valid: **diminishing returns**. It applies to all minerals at all times, not just oil and natural gas. The biggest deposits are found first, because they are most likely to be found even by chance. (Draw circles on a board, of varying sizes. Blindfold somebody, who then throws darts at the board. The bigger the circle, the more likely it is to be hit.) Moreover, the best and cheapest deposits are exploited first. Therefore, on average, mineral exploitation is always going from good to bad to worse, and real prices should have been rising since time immemorial.

But over twenty years ago, the fact had to be faced: Most real minerals prices not only did not rise in real terms over the long term, but with very few exceptions they actually fell. The price of any mineral is actually the uncertain, fluctuating, and ultimately unpredictable result of two opposing forces: diminishing returns **versus** increasing knowledge. Hence the irremovable element of price risk in any mineral operation. Recent oil and gas prices are only the latest, though not the most spectacular, example. In the 1970s, the price of uranium (another mineral important to Canada) soared like a rocket and dropped like a stone, partly because of collapsing delusions about demand, but also because of unexpected new supply coming in.

Thus the problem for an owner of Canadian gas, public or private, becomes: What will happen to the price at which gas reserves can be sold to the United States, and what will happen to the cost of finding-developing-extracting it?

Depletion and government policy. The government of Alberta, or of Canada, is not a profit-maximizing private company. It is like the trustee of a university, or a hospital, or a church. Such a trustee should in good conscience try to maximize the value of the assets he holds in trust. Thus, there is no difference between the objectives of public and private management. Nor is there any reason why they should use different discount rates. The uncertainty of future earnings is the same no matter who expects them. The diversification of the income or portfolio of the owner does not differ much between the whole equities market, on the one side, and the incomes of all Canadians, on the other. The incomes of Albertans are not as diversified as the equities market, so Alberta should if anything use a higher discount rate. These problems will be addressed in another section. The only reason for mentioning them here is to show that the government-private ownership dichotomy does not exist in the real world.

However, it is widely believed that government must take a wider view of depletion policy than seeing it in terms merely of present and future costs, prices, and incomes. It has a more important mission than maximizing the value of its constituents' assets. There is genuine fear of running out of oil and gas, and having Canadians or Americans freeze in the dark, or being thrown out of work. To stave off the future hardship, keep the gas in the ground. (A milder form of this fear is that high prices will impede development of the domestic Canadian market.)

This is mythical. In fact, there will always be unlimited amounts of oil or gas or anything else available to any American or Canadian buyer, **at the then-current market price.** The only danger or hardship is that this price may be cruelly high. But that is just another way of saying the same thing: The expected future high price makes it that much more valuable, either to use or to sell. The high future price, discounted down to the present, is an opportunity cost right now.

Future Natural Gas Prices

Probably the most important single factor in future natural gas price changes is the future world price of crude oil. This is **not** because the free market or unregulated price of gas is some proportion of the price of crude oil. A gas-saturated economy (like Alberta, or Louisiana-Texas) will under competitive conditions price gas far below crude-equivalent. A gas-poor economy (like New England) will normally price it higher. Moreover, the relation can change drastically over time. During a period of complete freedom for gas prices, the ratio of the price of gas on new long-term contracts as a percentage of the current price of crude oil varied between a low of 11% and a high of 60% with an unmistakable tendency to rise.[4]

But in any given place, a change in the price of crude oil will change natural gas prices at least in the same direction. The price of crude oil, as we have recently seen, is mighty uncertain. Not only is it subject to the general price uncertainty of any mineral; it is set by a cartel that has only

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[4]The period of 1945 to 1958. See M. Adelman, The Supply and Price of Natural Gas (Basil Blackwell: Oxford, 1962).

a limited knowledge of supply, demand, and its own power and cohesion. The OPEC nations in concert (not the organization OPEC, which is not important) raised the price by a factor of about 5 from 1973 to 1974, lost very little exports, and thereby reaped huge gains. A few years later, they returned to the charge and more than doubled the price from 1978 to 1981. In hindsight, that was a grave mistake. They lost more than half of their exports, they have been unable to keep the real price from dropping back by about a third, and in fact are earning no more, in real terms, than they did in 1978, before the great boost of 1979-81.

In these circumstances, nobody can prove it is wrong to expect world oil prices to rise again in the 1990s. That is the current consensus, voiced by many governmental bodies and by oil companies. Some governments expect the world oil price to increase by 1.94 percent per year in real terms through 2000 A.D., while the U.S. Department of Energy takes off at 5.94 percent per year.[5]

We have some doubts about this forecast, but they are not important. What matters is that the forecast has very little if any effect on what oil companies and other investors are actually doing. If they really expected the price to surge in the relevant future, they would be withdrawing at least some proved or semi-proved acreage from development, even when it would be profitable to develop it at today's prices, because it would be even more profitable in later years. Development drilling should be sharply down. In fact, it reached record levels in 1984, both for oil and for gas.[6] This was accomplished with many fewer drilling rigs than in 1981, as the

[5] **Oil & Gas Journal**, June 17, 1985, p. 60.

[6] **Oil & Gas Journal, March 8, 1985, pp. 171-72** (original source A.P.I.)

gross inefficiencies were removed, and the deep gas bubble burst. Deep gas had only been sought because of a now-vanished extravagant bonus conferred by regulation. So far in 1985, total gas wells (both exploration and development) are above the same period in 1984.[7]

A compendium by the **Oil & Gas Journal** shows that 20 oil companies will decrease exploration-production budgets this year, but only by 6.2 percent. It is not clear whether there will actually be less activity, given declining drilling costs and smaller bonuses.

The general uncertainty about prices will doubtless discourage exploration. Option theory has shown that the greater the uncertainty about price (or any other parameter), the more it pays to wait another year to see which way the dust settles.[8] Development decisions, on the other hand, depend on cost-price relationships. In general, good projects should not be delayed; poor projects should be. But for any given increase, the farther off in time the less important it becomes. DOE's 6 percent increase, 5 years away, has a present value of minus 34 percent (at a 10 percent real rate).

The moral: Poorer projects should be shelved in favor of better ones. An area with lower costs at the margin should expand faster, or contract more slowly, than an area with higher costs.

This brings us to the relative costs of creating reserves in Canada and in the United States. In brief: Costs are lower in Canada, more than

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[7]Drilling statistics from **Monthly Energy Review** and American Petroleum Institute, **Quarterly Review of Drilling Statistics**, usually summarized in **Oil & Gas Journal** and **World Oil.**

[8]See **Principles of Corporate Finance**, by Richard Brealey and Stewart Myers, 2nd ed., McGraw-Hill, p. 444.

offsetting transportation differentials in most cases, and therefore, if they were both put into the same market, Canadian development ought to be more rapid. Whether they would both expand, albeit at different rates, or Canadian development would displace U.S. development, cannot be stated until we consider the demand picture.

The Nature of Gas Reserves

It tends to be misleading to speak categorically of "nonrenewable" reserves and "finite" resources. Mineral reserves are renewable, and constantly being renewed, by spending billions every year on developing known deposits and discovering new ones.

But if the **cost** of this renewal rises above the price at which the mineral can be sold, then it will not pay to create new reserves. Existing reserves will be used up, and gradually dwindle to zero. Undiscovered resources, not sought, might as well be infinite. In fact, "finite resources" are a red herring. The only things that really matter are cost and price.

Statistics of natural gas reserves are the record of the **ready shelf inventory**, which has been developed out of a much larger but poorly known amount, often designated as "probable" reserves. Like all other inventories, it is perpetually being used up and replenished, "turning over" in the United States about every 10 years, in Canada about every 30 years. We will later show its importance in raising Canadian development costs.

Past predictions of ultimate reserves have usually been too low, but not because those who made the calculations were incompetent or ill-informed.[9] They estimated what would be found, given current knowledge of the earth's crust, current technology and current prices. As knowledge increased, so did reserves. As prices fluctuated, so did estimates of the exploitability of resources, especially those at the margin.

A recent report by a competent group[10] estimates remaining U.S. "recoverable resources" as from 430 to 900 Tcf conventional gas, and 140 to 700 Tcf non-conventional. "Because the definition of 'conventional' includes price and technology constraints, however, this range is conservative." All we can say is that annual additions of 15-20 Tcf out of a pool of 570-1600 Tcf can be sustained for as far ahead as anyone can rationally plan. What we need to know is the cost of the additions.

Similarly for Canada: Total proved reserves (76 percent of probable[11]) at the beginning of 1984 were 70.1 Tcf. Average expectation of "ultimately recoverable resources" in the Western Sedimentary Basin alone are an additional 88 Tcf, with almost the same potential in the Eastern Offshore. In the Western Basin, infrastructure already in place ensures that newly-found conventional reserves can be quickly placed on production.[12] As in the United States: If the highest reserve-addition was over 4 Tcf, and

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[9] In describing ultimate reserves as "too low" it must be acknowledged that ultimate reserves are unknown, only estimated. We only note that, historically, the estimates have almost always increased over time.

[10] **U. S. Natural Gas Availability: Gas Supply Through the Year 2000** (Washington, D. C.: U. S. Congress, Office of Technology Assessment, OTA-E-245, February 1985)

[11] See the section on Canadian development costs for the derivation of current "proved" reserves.

[12] Geological Survey of Canada, **Oil and Natural Gas Resources of Canada 1983**, Paper 83-31, p. 3.

our interest was in seeing whether the rate could be sustained at 5 or 6 Tcf, we can see that ultimate resources will be no serious constraint for the next decade.

As indicated earlier, what we should aim at learning are the comparative costs in Canada and the United States. We will explain how data limitations permit us to compare only development costs with a high degree of confidence. Fortunately, these are correlated with **exploration** costs and with **current operating** costs.

PRODCUTION COSTS IN CANADA AND THE UNITED STATES

Current Operating Costs

In each country, we have a good estimate for total operating costs, which can be partitioned between oil and gas within tolerable margins of error. Unfortunately, these are **average** costs, i.e., for all wells operating. But this is not a meaningful number if we aim to see at what cost an operator can create and deplete a new reserve. The great bulk of the wells are already in place, many of them for many years, and it pays to keep a well going so long as unit operating costs are a little less than price, although at such a cost it would never pay to drill another well, let alone develop a new reserve.

For the United States, but not for Canada, we can make a rough partial correction, by weighting each state's average production per well by its relative importance, as indicated by that state's total production. This results in quintupling the average production per well, and much reducing the estimated costs per unit produced (though not quite commensurately). (See Table 2.) But the correction is only partial, and for Canada it cannot

TABLE 2
U.S. NATURAL GAS OPERATING COSTS
(1983 US$/Mcf)

	UNWEIGHTED	WEIGHTED
1973	0.151	0.071
1974	0.191	0.086
1975	0.241	0.106
1976	0.260	0.122
1977	0.303	0.137
1978	0.328	0.145
1979	0.372	0.153
1980	0.482	0.188
1981	0.648	0.272
1982	0.722	0.296

Sources: U.S. Bureau of the Census, Annual Survey of Oil and Gas; World Oil, Annual Forecast issue.

be done at all.

This is important because operating costs vary substantially by well, according to productivity. By taking the reported operating expenditures for oil and gas in Canada, separating by resource according to the number of wells that are oil or gas producing,[13] and dividing the amount of gas produced into the resulting gas-allocated operating expenditures, rough operating costs per Mcf can be estimated, as shown in Table 3a. (Note that natural gas plant costs are excluded. They are discussed below.)

Canadian operating costs, estimated in this manner, accelerate unreasonably. However, a number of qualifications and adjustments remain to be made. First, operating costs per unit are a function of well productivity, which has declined, as can be seen in Figure 2. However, the decline in productivity has not been due solely to physical constraints, e.g., smaller fields being exploited, but is largely a reflection of the weak market for natural gas and policies that have constrained exploitation. In fact, deliverability is roughly twice the level of production, according to NEB estimates.[14] Since well operating costs are not closely related to production levels,[15] then the observed operating costs in Table 3a (from which

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[13]In Canada, 95% of natural gas is non-associated, and so no allowance has been made for associated gas. This calculation is rough, of course, and factors such as differences in depth between oil and gas wells have not been accounted for.

[14]According to the latest NEB report, **Canadian Energy, Supply and Demand, 1983-2005**, September 1984, deliverability from established reserves is estimated at 4.8 Tcf, versus actual production of 2.5 in 1983, according to **BP Review of World Gas, 1983**.

[15]Paul Bradley estimates that operating costs per well are a function of depth and whether the gas is sweet or sour. Specifically, the function he derives is:

Operating costs = c(500 + .2D)

where the results are in 1979 dolalrs, D is depth in feet, and c represents

TABLE 3A

CANADIAN GAS OPERATING COSTS

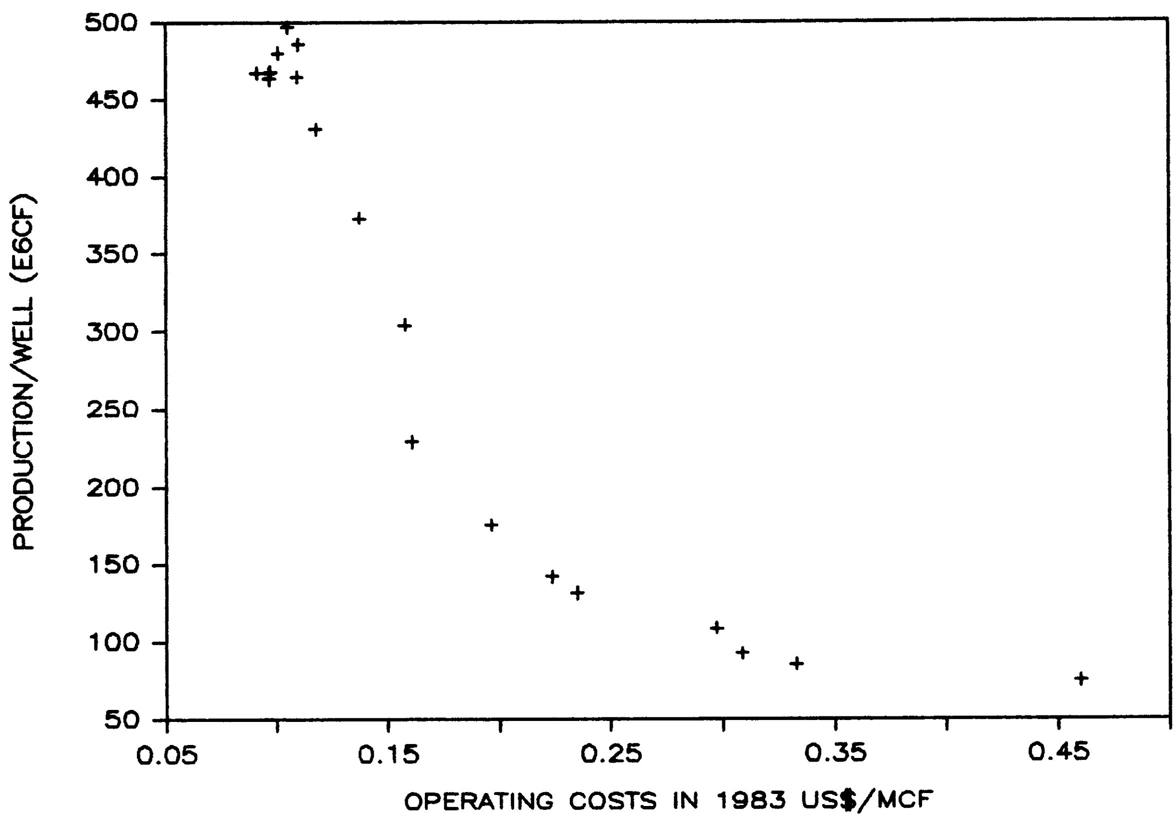
(C$)

Year	Gas Production (bcf)	Operating Expenses Attributable to gas (million $)	Cost per (\$/Mcf)	Mcf produced (1983 US\$/Mcf)
1955	145	2.6	0.0181	0.120
1956	192	3.1	0.0160	0.101
1957	242	3.8	0.0155	0.101
1958	333	5.6	0.0167	0.108
1959	436	6.3	0.0145	0.094
1960	472	7.8	0.0166	0.105
1961	690	8.7	0.0125	0.077
1962	831	10.5	0.0127	0.073
1963	899	15.0	0.0166	0.092
1964	1004	15.7	0.0156	0.084
1965	1082	20.5	0.0190	0.097
1966	1119	22.4	0.0200	0.097
1967	1209	23.7	0.0196	0.091
1968	1387	29.2	0.0211	0.097
1969	1548	35.8	0.0232	0.101
1970	1789	44.1	0.0246	0.105
1971	1942	55.6	0.0286	0.110
1972	2236	68.9	0.0308	0.109
1973	2313	89.8	0.0389	0.118
1974	2380	114.8	0.0482	0.137
1975	2348	170.7	0.0727	0.158
1976	2527	218.2	0.0863	0.161
1977	2479	336.3	0.1356	0.196
1978	2328	445.3	0.1913	0.223
1979	2617	611.5	0.2337	0.235
1980	2472	808.8	0.3271	0.297
1981	2392	888.4	0.3714	0.308
1982	2453	1067.8	0.4353	0.333
1983	2214	1254.8	0.5669	0.460

Sources:
Production and outlays from CPA 1983 Statistical yearbook.
Oil/gas drilling ratio is from ERCB, Reserves etc. 1981, Alberta.
For 1982 and 1983, well ratio is assumed.
Outlays excludes taxes and natural gas plants, and
expenditures in frontier areas.

Figure 2

OPERATING COSTS VS. PER WELL PRODUCTION



Sources: Statistical Handbook, Canadian Petroleum Association; and Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur, Energy Resources Conservation Board.

Figure 2 was derived) are overstated by constrained production. It might be an overcorrection to divide operating expenditures by deliverability, but the results should be more accurate than those provided by Table 3a. This suggests **average** operating costs of roughly 20 cents per Mcf, rather than 35 to 45.

In fact, using CPA Survey Data, as shown in Table 3b, operating costs were estimated as being much lower than in Table 3a, mainly because of a different split in allocation of operating expenditures between oil and gas fields (3 to 1 in favor of oil versus 3 to 2 in favor of natural gas using wells in operation).[16] The results are closer to those estimated using deliverability instead of production levels, climbing from 7.5 cents/Mcf in 1976 to 14.6 in 1983.

Some indication of marginal operating costs trends can be provided using Bradley's formulation. More specifically, if well operating costs are a function of depth, the fact that the average depth of gas development wells has not changed for a dozen years suggests that marginal costs per well have not increased. Since additions to reserves per well are falling very slowly in Canada since the early 1970s (see the section on future cost trends), then marginal operating costs should not have risen significantly.

Another approach to dealing with operating costs, one employed explicitly in the analysis of the Venture field and in Appendix B to this

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sweet gas (if equal to .6) or sour gas (if equal to 1). See "Costs and Supply of Natural Gas from Alberta: An Empirical Analysis," Discussion Paper No. 251, Economic Council of Canada, January 1984, p. A19. He relies on a study by Sproule Associates Ltd., "Evaluation of Canadian Oil and Gas Properties," Calgary 1979, for his data.

[16] "Historical Analysis of Industry Operating Costs for Oil and Gas Production in Western Canada," courtesy of Canadian Petroleum Association.

TABLE 3B
CANADIAN GAS OPERATING COSTS

	(C$/Mcf)	(1983 US$/Mcf)
1976	0.075	0.14
1977	0.054	0.078
1978	0.068	0.079
1979	0.09	0.09
1980	0.122	0.111
1981	0.138	0.115
1982	0.161	0.123
1983	0.194	0.157

Based on CPA survey data.

paper, is to assume that the revenues from natural gas byproducts (mainly liquids, but also sulphur) produce enough profits to offset total operating costs, and set them to zero. To some extent, operators probably take such an approach in considering whether or not to shut down a field, and it suggests one reason why they are reluctant to do so. The costs and benefits of byproduct production are discussed further below.

Finding Costs

As with operating costs, we have estimates of total expenditures on oil and gas discovery. Eliminating bonuses and rentals, which are transfer payments, though real from the perspective of the explorer, leaves geological and geophysical outlays, and exploratory drilling.

There is no good way to partition accurately the finding cost between oil and gas. Eglington[17] has used Imperial Oil's intent percentage, but its basis seems vague, and the company does not seem a representative sample of Canadian exploration effort. Moreover, the "intention" index agrees rather poorly with the industry's total number of successful oil and gas exploratory wells, i.e., those which actually find something. Most exploratory wells are dry holes. Discovery is by its nature a groping into the unknown, and the company is looking primarily for hydrocarbons, though some areas are considered much more gas prone than oil prone.

An additional problem is with the denominator, how much is discovered. The amount announced as "new discoveries" every year represents a fraction of the reserves in the fields that have been discovered. The pertinent issue is

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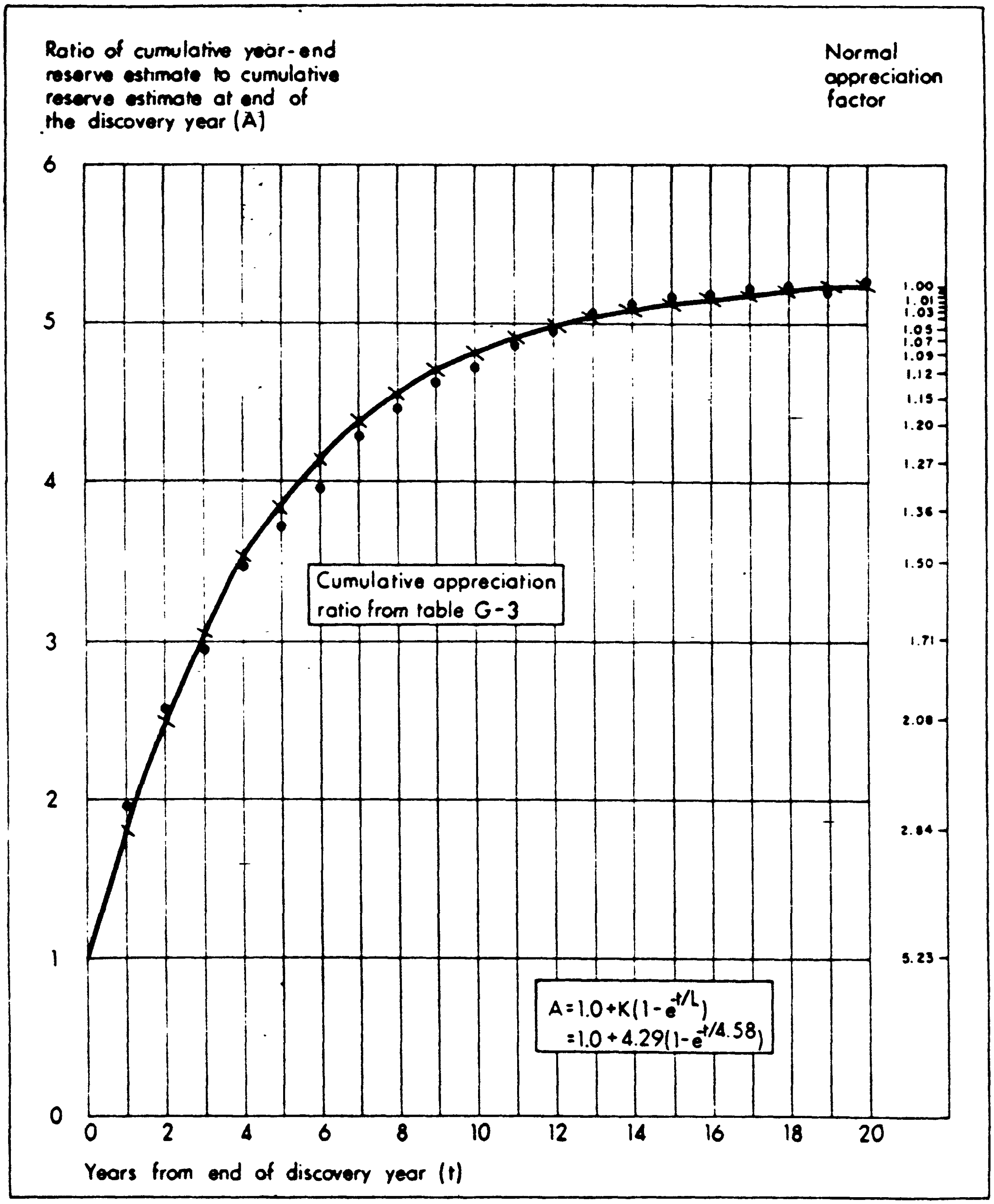
[17] "Observed Costs of Oil and Gas Reserves in Alberta," Peter Eglington and Maris Uffelman, Economic Council of Canada Discussion Paper No. 235, August 1983.

FIGURE 3

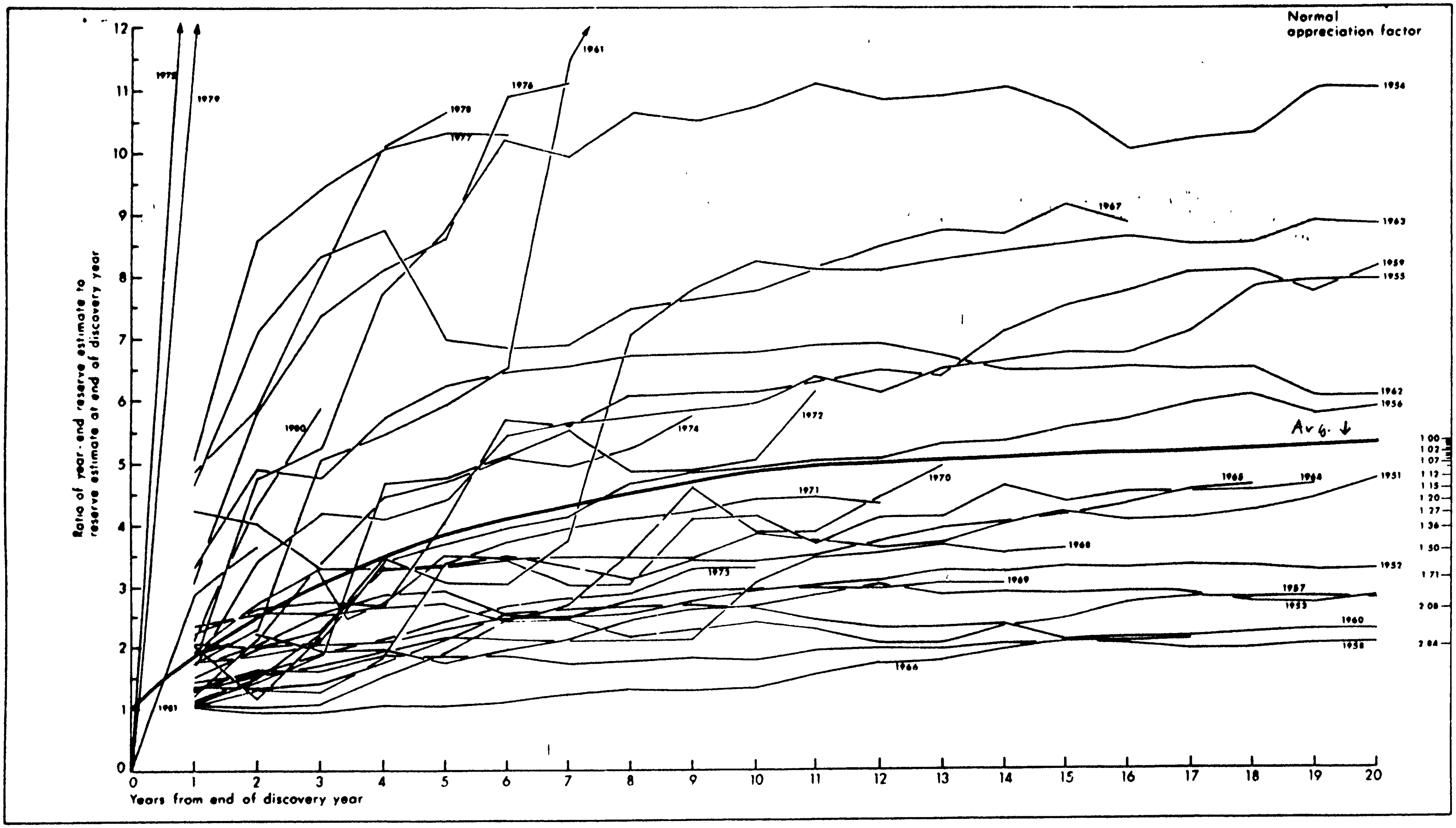


NORMAL APPRECIATION OF INITIAL ESTABLISHED RESERVES OF MARKETABLE GAS.

Source: "Gas Reserve Trends", Alberta Energy Resources Conservation Board, 12/31/83.

ERCB

FIGURE 4



APPRECIATION OF INITIAL ESTABLISHED RESERVES OF MARKETABLE GAS RELATIVE TO RESERVES AT THE DISCOVERY YEAR

Source: "Gas Reserve Trends", Alberta Energy Resources Conservation Board, 12/31/83.

ERCB

the size of the fraction represented, and whether it is shrinking, growing, or constant.

While some analysts suggest that little new oil is to be "found" in existing fields, this has not proved to be the case.[18] In fact, in 150 giant oil fields in the United States, discovered by the late 1950s, reserves grew by 7 billion barrels between the end of 1977 and the beginning of 1984.[19] The typical pattern for reserve appreciation is shown in Figure 3, which shows the appreciation of newly-discovered natural gas fields in Alberta over time; it approaches a certain limiting value of what is eventually credited to the newly-found reservoirs.

For Canada, one could do this for every discovery year since 1947. Figure 4 shows the "convergence curves" for Alberta beginning with 1947, but clearly there are some shifts going on so the longer-term average is not safe to use. During the last 10 years, the buildup in the first few years has in all cases lain above the long-term average, when theory suggests that increasing knowledge and higher prices should lead to the opposite result; that is, higher initial estimates (i.e., better) of ultimate reserves discovered, leading to a smaller (relative) appreciation.

Uhler corrects for this in an interesting manner.[20] Since most of the extremely high appreciation factors are due to insufficient evaluation of

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[18]Richard Nehring, in **Giant Oil Fields and World Oil Resources** (Rand: Santa Monica, 1978), argued that "The potential for reserve growth from extensive development of known fields does not appear to be significant."

[19]See **Oil and Gas Journal**, 1/27/58, 1/30/78, and 1/30/84. Thirty-three fields in the latest list were excluded for not appearing on one of the lists, i.e., as being either too young or or having ceased production.

[20]"The Potential Supply of Crude Oil and Natural Gas Reserves in the Alberta Basin," Russell S. Uhler with Peter C. Eglington, for the Economic Council of Canada, December 1983. See pages 126-136.

pools during the discovery year, he uses the year after discovery as well, reducing the variance substantially. His results, which include the impact of price on appreciation, suggest an appreciation factor of 4.5 for oil and 3.6 for natural gas.

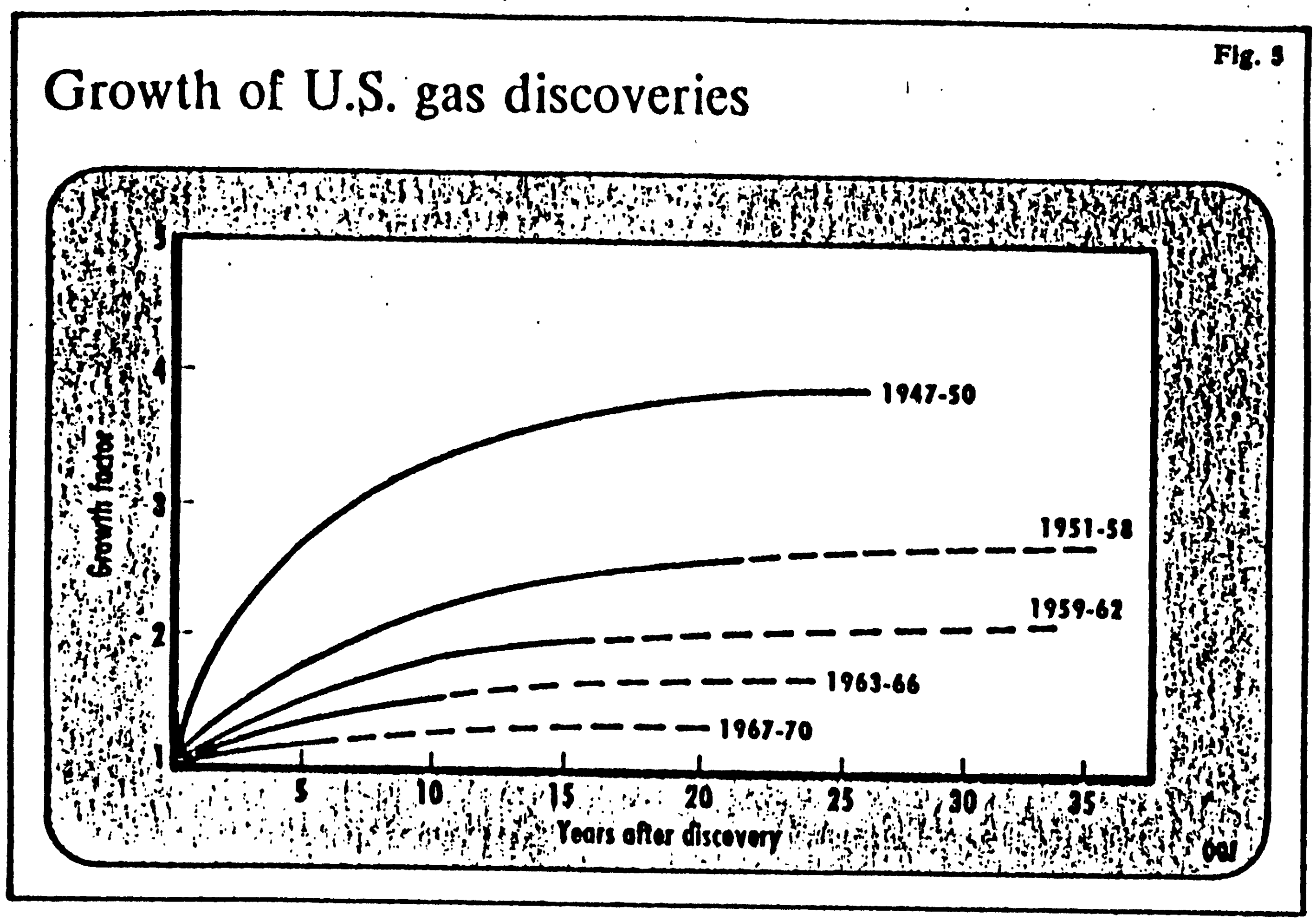
Recent work by Michael Prime and Nancy Laird is illuminating,[21] pointing out that in the ERCB's estimate, it concentrated on reserve appreciations for fields over 300 million cubic meters of natural gas in size (10.6 Bcf). (Uhler does the same.) Since, in recent years, a greater percentage of reserve additions are due to smaller fields, and since, Prime argues (and Uhler concurs) smaller fields experience less appreciation, the result is that the ERCB's longer-term estimate of 5.2 is less appropriate for recent years. Instead, Prime and Laird argue for an appreciation figure slightly less than 3.

The effect of such an estimate on exploration costs is direct and significant. By lowering the amount of adjusted discoveries by 40%, the costs are escalated by a like amount. Given a poor evaluation of the actual costs, this is indicative but not definitive.

For the United States, we have only a brief window, between 1966 and 1979. But since periods of less than 6 years are of doubtful reliability, the window is really only between 1966 and 1973. Richard Meyer's estimate of natural gas reserve appreciation in the pre-1970 period is shown in Figure 5, and Figure 6 shows our own estimates of the 1966-1973 years. As can be seen, the appreciation factor for reserves in the United States appears to be much smaller than the ERCB's estimate for Alberta, but more in keeping with Prime

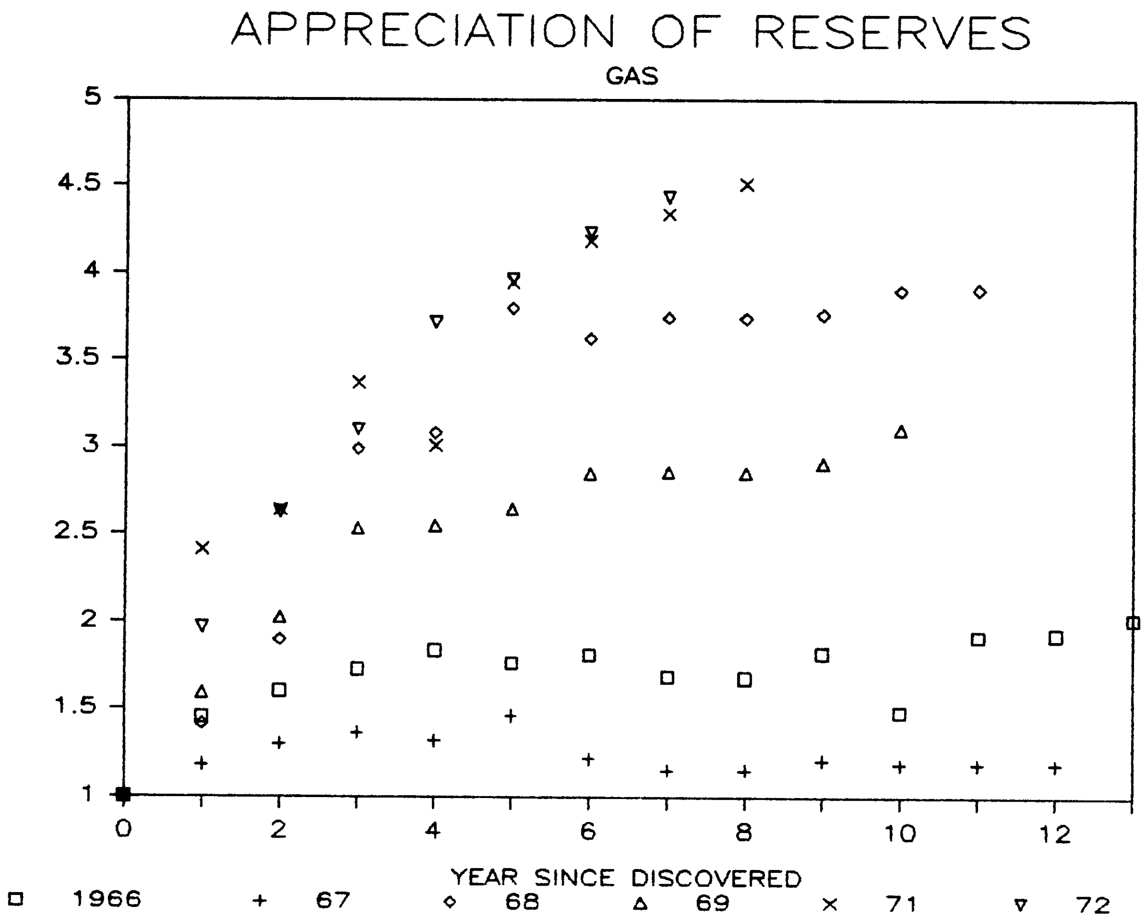
[21] "Appreciation of Oil and Natural Gas Reserves," Internal Memo, courtesy of Michael Prime and Nancy Laird, Shell Canada Resources, 1985.

FIGURE 5



Source: "A Look at Natural-gas Resources," Richard F. Meyer, Oil and Gas Journal 5/8/78, p. 342.

Figure 6



Source: Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada, American Gas Association, American Petroleum Institute, and Canadian Petroleum Association, various issues.

and Laird. The extent to which this results from geological, regulatory, or interpretive factors cannot be separated out, and unfortunately the data are no longer collected, preventing estimation under the current technological, price, and regulatory environment.

The upshot is that while the numbers can be used to indicate trends, they cannot be used to estimate cost levels. Even if valid, they are extremely unreliable, experiencing wild year-to-year swings. While we feel this issue requires substantially more study, it raises a clear caution against excessive reliance on reported discoveries to assess exploration costs.

However, we have an important proxy for finding costs, which is the sales value of known but undeveloped gas deposits. As indicated at the start, an owner will not sell off gas at a price that does not cover the (a) reproduction cost, or (b) the present value of the future net revenues. These two are proxies for one another.

In the United States, there have been many sales of companies that had both gas and oil in the ground, but so far we have not been able to calculate respective values. One needs, first, to back out non-hydrocarbon assets; secondly, to partition between oil and gas; thirdly, to calculate how much of the value of the oil or gas is a reimbursement for development cost. A study at M.I.T. estimates about $1.50 per Mcf in 1979-81; probably the greater part was reimbursed development costs, since the bulk of the reserves were developed.[22]

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[22]The estimate indicated gas reserves at $1.48/Mcf, and oil at $12.05/barrel, inground and developed. Alfred T. D'Aliberti, "Implicit Market Valuation of Crude Oil and Natural Gas Reserves," M.S. Thesis, Sloan School of Management, M.I.T. (June 1984), p. 39.

In Canada, some information is generated by assembling undeveloped parcels for one sales contract. The sales value of these parcels in 1984-85 has varied between C35 and C65 cents, an average of about C50 cents, or US37.5 cents. The only reference to market valuation of a specific U.S. natural gas field comes from a 1982 sale of a share of the E. Anschutz field. The evidence, which is conflicting, suggests that the reserves were valued at approximately $0.50/Mcf.[23]

In addition, others have performed analysis on supply costs in Canada, the most notable being Eglington and Uffelman.[24] The results they acheived using the same data and a somewhat different methodology, are similar to those discussed here.

Development Costs: Canada

Tables 4a and 4b present our estimates of Canadian development costs, which we translate ultimately into the above-ground price in U.S. dollars, since our basic interest is in comparing them with the U.S. market, into which gas will be exported.

The first step is to partition Canadian development expenditures between oil and gas, according to the number of development wells drilled. Since there are relatively few development dry holes, the possible error is much

[23] First Boston Corporation valued the total field at $3 billion dollars, and estimated reserves at 800 million to 1.2 billion barrels of oil equivalent. (Thus, our $0.50/Mcf estimate.) The source for this estimate is **Oil and Gas Journal**, 8/16/82, p. 60. It has been noted that Mobil also acquired 250,000 acres of undeveloped land elsewhere, and that the field has exceptionally high development costs. See **The Wall Street Journal**, 8/12/82, p. 2, which puts the price Mobil paid at exceeding $500 million for 100 million barrels of oil equivalent, or 9-17% of the field.

[24] Eglington and Uffelman, *op. cit.*

TABLE 4A
CANADIAN GAS DEVELOPMENT COSTS
($C)

Year	Proved Marketable Gas Reserves added (mcf)	Total Gas Development Investment Outlays (million $)	In ground Cost ($/Mcf)	Present Mcf Factor	Above ground value ($/Mcf)
1955	2,155,348	8.5	0.004	10.0	0.04
1956	2,807,173	11.3	0.004	10.1	0.04
1957	1,214,387	14.9	0.012	9.6	0.12
1958	2,586,628	21.3	0.008	7.0	0.06
1959	3,358,548	24.3	0.007	7.5	0.05
1960	4,040,848	27.9	0.007	7.0	0.05
1961	3,235,916	45.0	0.014	5.4	0.08
1962	2,517,598	38.9	0.015	5.4	0.08
1963	2,653,104	36.7	0.014	5.1	0.07
1964	7,308,842	36.5	0.005	5.2	0.03
1965	2,130,353	34.9	0.016	5.4	0.09
1966	4,202,939	33.3	0.008	5.9	0.05
1967	3,443,885	47.1	0.014	5.7	0.08
1968	3,380,386	66.5	0.020	5.8	0.11
1969	5,838,870	77.6	0.013	5.9	0.08
1970	3,203,612	97.1	0.030	5.1	0.16
1971	1,929,491	115.2	0.060	4.2	0.25
1972	1,929,491	138.2	0.072	3.8	0.27
1973	1,929,491	195.1	0.101	4.1	0.41
1974	2,676,490	260.5	0.097	4.3	0.42
1975	4,040,144	343.7	0.085	4.4	0.37
1976	2,652,153	634.9	0.239	4.8	1.16
1977	3,066,353	635.6	0.207	4.6	0.96
1978	3,532,492	784.9	0.222	5.4	1.19
1979	3,914,954	990.9	0.253	5.9	1.48
1980	2,071,983	1542.8	0.745	6.6	4.94
1981	3,425,152	1464.7	0.428	8.3	3.55
1982	1,650,900	1126.7	0.682	7.1	4.85
1983	2,161,581	436.4	0.202	6.5	1.30

Sources: Discount rate is Canadian T-bill rate plus 8% (with 1951 interpolated).
Depletion rate calculated elsewhere from CPA data, using yearly average reserves.
Reserves from CPA Statistical Yearbook, 1983. Pre-78 are proved, post are probable times .7. For 1972, original total reserve additions were negative, so 1971-73 represent the three-year average.
Investment is taken from CPA Statistical Handbook, 1983.
Investment in natural gas plants excluded.
The Present Mcf Factor is explained in Appendix A.

Table 4 B

CANADIAN GAS DEVELOPMENT COSTS
(1983 US$)

Year	Proved Marketable Gas Reserves added (mcf)	Total Gas Development Investment Outlays (million $)	In ground Cost ($/Mcf)	Present Mcf Factor	Above ground value ($/Mcf)
1955	2,155,348	55.5	0.0258	10.4	0.27
1956	2,807,173	71.0	0.0253	9.3	0.24
1957	1,214,387	95.8	0.0788	8.3	0.66
1958	2,586,628	135.7	0.0525	6.8	0.36
1959	3,358,548	156.1	0.0465	6.0	0.28
1960	4,040,848	175.5	0.0434	6.3	0.28
1961	3,235,916	272.5	0.0842	5.1	0.43
1962	2,517,598	222.6	0.0884	4.7	0.41
1963	2,653,104	202.6	0.0763	4.6	0.35
1964	7,308,842	195.3	0.0267	4.6	0.12
1965	2,130,353	177.6	0.0834	4.7	0.39
1966	4,202,939	159.8	0.0380	4.7	0.18
1967	3,443,885	217.1	0.0630	4.7	0.30
1968	3,380,386	304.1	0.0900	4.4	0.39
1969	5,838,870	88.7	0.0152	4.2	0.06
1970	3,203,612	412.6	0.1288	3.9	0.51
1971	1,929,491	476.8	0.2471	3.8	0.94
1972	1,929,491	527.6	0.2734	3.4	0.94
1973	1,929,491	644.4	0.3340	3.3	1.10
1974	2,676,490	737.0	0.2754	3.1	0.85
1975	4,040,144	792.8	0.1962	3.2	0.63
1976	2,652,153	1298.9	0.4897	3.3	1.61
1977	3,066,353	1099.9	0.3587	3.4	1.21
1978	3,532,492	1098.6	0.3110	3.6	1.12
1979	3,914,954	1141.4	0.2915	3.5	1.01
1980	2,071,983	1466.4	0.7077	3.7	2.62
1981	3,425,152	1220.2	0.3562	3.8	1.37
1982	1,650,900	861.2	0.5216	3.8	1.99
1983	2,161,581	354.1	0.1638	4.2	0.68

Sources: Discount rate is 10%.
Depletion rate calculated elsewhere from CPA data, using yearly average reserves.
Reserves from CPA Statistical Yearbook, 1983. Pre-78 are proved, post are probable times .7. For 1972, original total reserve additions were negative, so 1971-73 represent the three year average.
Investment is taken from CPA Statistical Handbook, 1983.
Investment in natural gas plants and frontier areas excluded.

less than with exploratory wells. Allocation by number of wells understates gas expenditures, since gas wells are usually more expensive. It also overstates them, since a substantial amount of gas is associated, though not as much as in the United States, and development cost is much less. Dividing the expenditure figure by gross marketable gas reserves added during the particular year yields the in-ground cost per Mcf, in Canadian dollars. (We exclude frontier areas throughout, since we are trying to ascertain levels and trends within the Western Basin of Alberta, British Columbia, and Saskatchewan. It is not clear what biases are introduced by use of global figures.)

For gross marketable reserves added, we have undertaken a transformation from the original CPA data, which shows "established" reserves. This refers to what was once known as "probable" reserves, usually 20% to 40% above "proved" reserves, reflecting natural gas which has not yet been developed but which, based on seismic data, the geology of the field, etc., is considered to have a high probability of being present. Naturally, the ratio of proved to probable reserves is not a constant, but varies according to a variety of factors, including chance. However, 76% is the ratio of proved to probable during the 1970s.

During the 15-year period 1955-1969, the in-ground cost fluctuated, though there was an upward trend. During the next few years, investment outlays jumped around rather wildly; reserve additions, no more than in previous years. This indicates that much of the fluctuations in the cost of booking an additional Mcf of reserves was due to deranged factor prices, which went through a wild boom-and-bust in both the United States and Canada. One would especially like to have the 1984 numbers, since the recent

IPAA estimates shown in Table 5 are of an additional 14 percent decrease in factor costs from 1983 to 1984.[25]

It may be permissible to consider the decade 1961-69 as a unit, since it began with a substantial jump, to 8.4 cents, which was not surpassed until 1968. The 1961-69 average was 6.3 cents per Mcf in ground; 1983 was 16.4 cents, an increase by a factor of 2.61 in 18 years, or 5.5 percent per year. This is, to be sure, a pretty cavalier dismissal of expenditures in the intervening years. We cannot pretend to have explained what made them gyrate so wildly. But if our perspective is forward-looking, we are not well advised to use the intervening years as the basis for estimating costs in 1984 and later years.

However, this may be too conservative or pessimistic a view. When there is a considerable increase in drilling in a short time, there is (1) a bidding-up of factor prices, (2) much inefficiency in factor utilization, and (3) a rapid running-down of the backlog of prospects. Smaller, poorer deposits get drilled up for lack of the better reservoirs, which would take some time to find and delineate. Therefore, costs may not rise in the long run at the rate seen in the short run, even apart from any breakthroughs or major new areas opened.

In trying to get behind money figures, we can discern that reserves-added per new gas well drilled fell precipitously from 1968 to about 1976, after which it stabilized at a relatively low level. The number of wells completed per rig-year also fell sharply through 1979, but then climbed back to a record high in 1983. Thus rig-time needed to develop an additional unit of gas reserves, a good measure of the real cost of the reserves,

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[25] IPAA, **Report of the Cost Study Committee,** May 15, 1985.

increased greatly during 1968-1979, in agreement with our money cost measurements, but has dropped considerably since then, though by no means to the levels of 1968.

Applying similar techniques to U.S. data yields the development costs shown in Table 6. As can be seen, the marginal cost of U.S. field development is well above that of Canada's. In fact, only the much faster capital recovery time, as evidenced by a much lower present Mcf factor, keeps the above-ground costs within reason. (This provides some idea of the costs imposed on Canadian producers of slow capital recovery.) The fact that marginal development costs surpass average wellhead values would normally suggest data or interpretive problems; however, the regulatory environment seems more likely to be at fault.

In a competitive market, marginal development costs should always be equal, whatever the field or environment. However, given different prices paid for certain types of gas, i.e., new gas, deep gas, tight gas, etc., the variance in marginal costs would be quite high in the early 1980s, surpassing average wellhead values substantially, especially given the cushion of "old" gas prices. As discussed below, marginal development costs should drop back close to the level prevalent in the pre-NGPA era.

Development costs trends are our best proxy measure of exploration cost trends, since diminishing returns to exploration, yielding smaller and harder-to-develop fields, are reflected in rising development costs. Since they are more stable than exploration costs, they are a more accurate monitor of cost trends. Mineral replacement costs are another.

Table 5

IPAA Drilling Cost Index

1979 = 100

	Unadjusted for Well Distribution	Adjusted for Well Distribution
1963	31.7	
1964	32.3	
1965	33.5	
1966	34.1	
1967	35.6	
1968	36.9	
1969	38.2	
1970	40.5	
1971	44.6	
1972	47.2	
1973	49.0	
1974	58.7	
1975	68.4	
1976	74.6	
1977	81.2	
1978	90.5	88.7
1979	100.0	100
1980	115.7	110.7
1981	134.2	126.4
1982	143.2	141.8
1983	133.8	125.4
1984	131.3	117.3

Source: IPAA cost study committee reports for U.S.

Mineral Replacement Cost and Mineral Rents

Throughout this analysis, we have analyzed development costs, but have not explicitly calculated finding costs. In this section, we explain why for the purposes of this study it is not necessary to provide explicit quantification.

Expenditures on finding and on development are available year by year in Canada and in the United States through 1982. The U.S. Bureau of the Census series was discontinued after that time; it may be resumed beginning with data for 1984.

"Finding costs" are usually a misnomer. "Finding Costs," as discussed by many analysts,[26] are often used to designate the sum of development costs plus exploration. This addition lumps together two separate activities. To compare this sum with reserves "found" during the year compounds the error. Very little of the reserves added in a given year have been found during that year. Such "costs" should be disregarded.

"Discoveries:" initial vs eventual. Although data covering a year's expenditures on oil and/or gas discovery may be available, especially in the United States and Canada, the amount discovered rarely is available. The usual item "discoveries" is only that small part of newly-found fields that has actually been developed and made ready for production in the given year.

For Alberta since 1947, and for the United States only during 1966-79, it is possible to add in the additions to reserves made in a given field in

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[26] See, for example, **Oil & Gas Reserve Disclosures: Survey of 375 Public Companies 1980-1983**, Arthur Andersen & Co., Summary Edition, pp. S26-S27.

TABLE 6
U.S. NATURAL GAS DEVELOPMENT COSTS
(1983 US$/Mcf)

	Development Cost in-ground	Development Cost above-ground	Present Mcf Factor
1973	1.194	2.365	1.98
1974	0.853	1.674	1.96
1975	0.706	1.405	1.99
1976	1.222	2.385	1.95
1977	1.107	2.114	1.91
1978	1.005	1.918	1.91
1979	1.574	2.954	1.88
1980	1.489	2.784	1.87
1981	0.866	1.626	1.88
1982	1.283	2.520	1.96
1983	0.989	1.977	2.00

Sources: U.S. Bureau of the Census, Annual Survey of Oil and Gas; World Oil, Annual Forecast issue.

years after the discovery year. Calculations have been made, showing that the eventual reserve figure is, very roughly, 3 to 6 times the initial. (See Figures 3 through 6.) But there is great variation field to field and region to region.

For recent years, therefore, even in Alberta, it is not possible to say how much has been discovered in the course of the year.

However, even if we have a good estimate of the eventual reserve additions credited to a field discovered in a given year, little may be due to expenditures in that year.

For these reasons, the attempt to estimate finding costs year by year is ill-advised, except to show orders of magnitude. The situation is very different with the development of known reservoirs, where expenditures made during the year add to reserves and capacity during that year. There is a time lag here, which U.S. data show is minor, though not negligible. (See the item "work in progress" in U.S. Census Bureau **Annual Survey of Oil & Gas**, published 1974-82, now discontinued.)

Exploration costs and in-ground values. In any given reservoir, development costs per barrel must at some point begin to increase with more intensive development. Hence it pays to incur the costs of finding additional reservoirs, when the costs of finding-plus-development of new fields is less than the costs of development of old ones.

The value of a newfound but undeveloped unit of oil or gas in the ground is like that of every other capital asset. It is the lesser of (a) the cost of finding another unit, or replacement cost, or (b) development rent, the present discounted value of the expected development profit, over and above the needed return on the development investment. A rule-of-thumb of 10 percent for the appropriate discount factor happens to be fairly close to the best estimates for the United States and Canada, for exploration-cum-development companies. This indicates that strictly development investment should fetch somewhat less, exploration more.

In-ground oil or gas that is not expected to be used for a long time is very heavily discounted. Thus, at 10 percent an Mcf of gas which one expects to sell at (say) $4 per Mcf, and which will require expenditures of (say) $2 per Mcf, for a profit of $2 in 20 years, will today be worth only 30 cents. Discounted at 12 percent, it would be worth 21 cents.

Since finding cost and expected profit are proxies for one another, our best approximation to finding costs is: the market value of an undeveloped unit of natural gas. In Canada, a rough estimate of market value is about US 35 cents in recent years. This is, however, an overestimate, because it includes some development costs that must be incurred; otherwise there can be no estimate of how much gas is being sold in-ground.

"Long-run marginal costs" are used in two different, though not inconsistent senses. In a recent paper by Paul Bradley,[27] the various gas--producing basins are arrayed from lowest to highest-costs, and long-run marginal cost is considered to be the costs of climbing the ladder, going from better to worse basins. Thus the Bradley study addresses the slopes of the respective marginal cost curves.

But the annual statistics on expenditures and reserve additions involve all these basins. The basic theory is that a basin is developed in stages

[27] "Costs and Supply of Natural Gas from Alberta: An Empirical Analysis," Discussion Paper No. 251, Economic Council of Canada (January 1984).

or tranches, going from lower to higher costs. The market serves as a scanner. At any given moment, it chooses the least-cost tranches from all the basins. The level of long-run marginal cost is approximately equal in all basins at any given moment. Fluctuations around the average are due to chance and to the lumpiness of the development.

Neither the Bradley view, nor the view taken in this paper, can give us future finding costs. We can only approximate them, in two ways.

The first is by taking the subjective estimates of firms in the industry, as explained above. These estimates must be taken seriously because they help determine how much is to be developed in the future. The farther-off the expected higher prices, the less important they are today. The common sense explanation is: The farther off in time is any event, the greater the odds are against it ever happening, because of factors unperceived or undervalued today.

The second is by using a higher discount rate for future development projects, in reservoirs not discovered. In other words, an oil-gas operator who must decide whether or not to explore will do so only if the profit on the development of the successful fields will be large enough to make it worth investing in a number of projects, most of them barren. In the various calculations made in the text, we have used 10 percent, real, as approximately a market rate of return on development. We would need to use something higher, roughly 15-20 percent, if we were to allow for finding cost as well. Unfortunately, the risk factors are too little known for us to try this approach.

Byproducts: Natural Gas Liquids and Sulphur

In 1983, the sale of natural gas liquids and sulphur, which are largely but not totally byproducts of natural gas production, totaled as much as 29 percent of the value of combined natural gas and byproduct sales. At the same time, investment in gas processing plants for the removal of these byproducts from natural gas equaled 31 percent of combined total gas field development expenditures (i.e., field development and gas plant construction), and the operating costs of these plants was 30 percent of the total. (See Table 7.) Clearly, byproducts play an important role in the Canadian natural gas industry, in terms of both costs and benefits.

Although byproducts production appears extremely profitable, these figures are averages. In reality, some fields can be rendered uneconomical because of the extra costs of removing byproducts, usually sulphur, while others are made more profitable by their presence, especially natural gas liquids, for which transportation costs are lower than natural gas, and no large inventory of unsold product exists, as with sulfur.

Unfortunately, the byproducts side of the industry is not as closely analyzed as oil and natural gas, and the data tend to be aggregated, making it difficult to determine costs precisely. Our estimates using this aggregate data are presented below, with a separate discussion of some problems inherent in sulphur production.

A number of approaches can be followed in determining the level of costs per unit of production. Since the expenditures cannot be broken down and assigned to particular products very easily, and since byproduct development and production will only occur in conjunction with natural gas, for good or ill, it seems most appropriate to describe the costs and benefits in terms of

TABLE 7
Costs and Value of Byproduct Production
(million C$)

EXPENDITURES

	Natural Gas Development	Gas Plant Construction	Gas Operating	Gas Plant Operating	Value of Byproduct Sales
1955	8.5	6	2.6	3.0	4.6
1956	11.3	18.5	3.1	4.0	4.5
1957	14.9	31.7	3.8	6.0	6.9
1958	21.3	40.7	5.6	8.8	7.6
1959	24.3	13.6	6.3	12.3	11.7
1960	27.9	20.6	7.8	11.8	16.4
1961	45.0	61.6	8.7	23.2	25.6
1962	38.9	20.7	10.5	30.9	42.1
1963	36.7	36.7	15.0	32.8	75.7
1964	36.5	42.7	15.7	37.7	94.4
1965	34.9	35.4	20.5	35.3	115.9
1966	33.3	56.9	22.4	40.4	140.1
1967	47.1	107.0	23.7	52.0	178.1
1968	66.5	91.2	29.2	57.0	202.4
1969	77.6	97.1	35.8	61.4	197.0
1970	97.1	179.8	44.1	73.1	189.2
1971	115.2	250.5	55.6	91.0	210.8
1972	138.2	128.6	68.9	112.5	267.8
1973	195.1	69.5	89.8	121.5	372.9
1974	260.5	138.2	114.8	144.8	715.1
1975	343.7	147.5	170.7	181.2	852.2
1976	634.9	170.7	218.2	217.5	885.2
1977	635.6	155.5	336.3	259.1	1066.3
1978	784.9	218.8	445.3	295.7	1082.7
1979	990.9	301.9	611.5	350.8	1381.1
1980	1542.8	311.6	808.8	405.2	1924.0
1981	1464.7	347.1	888.4	446.1	2326.5
1982	1126.7	522.9	1067.8	505.3	2448.5
1983	436.4	195.8	1254.8	548.8	2535.2

natural gas reserves developed and produced. In Table 8, development costs can be seen to vary a great deal, presumably reflecting "lumpy" investments in a large field with sour gas or a particularly rich NGL feed. Still, an above-ground cost of about 20 cents (US) per Mcf appears to be the norm for the past decade. One factor in holding these costs down has been the higher decline rate, and quicker capital recovery, for NGLs: 5.2 percent versus 2.4 percent for natural gas in 1983.[28]

As for operating costs, shown in Table 9, more stable behavior can be seen. Steady increases in costs are observed, on the order of 3.5 percent per year over the whole period, although the past decade witnessed real cost inflation of over 6 percent per year. In part, this may reflect the exploitation of increasing amounts of sour gas, but it must be assumed that low utilization rates due to poor markets, as discussed in the section on operating costs above, have seriously inflated the observed per unit costs.

The most important observation, however, is the marginal profit observed. As Table 10 shows, the "marginal" profit on overall byproduct production is quite high still. (Operating costs are average, not marginal, but are unlikely to have accelerated beyond the observed average levels. See above.) A major impetus behind the high level of profitability, especially considering the much lower levels in pre-1973 years, is the high value for NGLs, due to the oil price shocks of the 1970s. Weaker oil prices in the future will hold these profits down.

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[28]Canadian Petroleum Association, **Statistical Handbook**, 1983. Note that established reserves were used, with no correction to proved reserves.

TABLE 8
CANADIAN GAS BYPRODUCT DEVELOPMENT COSTS
(1983 US$)

Year	Proved Marketable Gas Reserves added (mcf)	Gas Plant Development Investment Outlays (million $)	In ground Cost ($/Mcf)	Present Barrel Factor	Above ground value ($/Mcf)
1955	2,155,348	22	0.010	10.5	0.10
1956	2,807,173	64	0.023	10.9	0.25
1957	1,214,387	110	0.090	12.2	1.10
1958	2,586,628	137	0.053	10.0	0.53
1959	3,358,548	45	0.013	8.4	0.11
1960	4,040,848	67	0.016	7.1	0.12
1961	3,235,916	189	0.058	5.1	0.30
1962	2,517,598	59	0.023	3.7	0.09
1963	2,653,104	102	0.039	3.6	0.14
1964	7,308,842	117	0.016	3.0	0.05
1965	2,130,353	95	0.045	3.0	0.13
1966	4,202,939	148	0.035	3.3	0.12
1967	3,443,885	270	0.078	3.8	0.30
1968	3,380,386	221	0.065	3.5	0.23
1969	5,838,870	224	0.038	3.7	0.14
1970	3,203,612	405	0.127	3.4	0.43
1971	1,929,491	556	0.288	3.2	0.92
1972	1,929,491	280	0.145	2.7	0.39
1973	1,929,491	142	0.073	2.5	0.18
1974	2,676,490	264	0.099	2.5	0.25
1975	4,040,144	248	0.061	2.5	0.15
1976	2,652,153	282	0.106	2.5	0.26
1977	3,066,353	225	0.073	2.3	0.17
1978	3,532,492	275	0.078	2.8	0.22
1979	3,914,954	340	0.087	2.7	0.23
1980	2,071,983	322	0.155	2.6	0.41
1981	3,425,152	319	0.093	2.5	0.23
1982	1,650,900	440	0.267	2.5	0.68
1983	2,161,581	159	0.074	2.9	0.21

TABLE 9
CANADIAN GAS PLANT OPERATING COSTS
(1983 US$)

Year	Gas Production (bcf)	Operating Expenses Attributable to gas plants (e6 $)	Cost per Mcf produced ($/Mcf)
1955	145	10.8	0.0746
1956	192	14.0	0.0730
1957	242	21.2	0.0874
1958	333	30.0	0.0899
1959	436	41.7	0.0957
1960	472	39.2	0.0830
1961	690	72.4	0.1050
1962	831	90.1	0.1084
1963	899	93.4	0.1039
1964	1004	105.0	0.1046
1965	1082	95.3	0.0881
1966	1119	106.0	0.0947
1967	1209	130.5	0.1079
1968	1387	136.2	0.0981
1969	1548	139.3	0.0900
1970	1789	162.9	0.0910
1971	1942	201.3	0.1036
1972	2236	240.1	0.1074
1973	2313	235.8	0.1020
1974	2380	262.9	0.1105
1975	2348	300.7	0.1281
1976	2527	351.8	0.1392
1977	2479	361.8	0.1459
1978	2328	354.3	0.1522
1979	2617	374.9	0.1433
1980	2472	395.7	0.1601
1981	2392	400.8	0.1675
1982	2453	424.9	0.1732
1983	2214	445.3	0.2012

TABLE 10
PROFITABILITY OF GAS BYPRODUCTS
(1983 US$/Mcf)

	Byproduct Development Costs per Mcf Produced	Byproduct Operating costs per Mcf Produced	Value of Byproduct per Mcf Produced	Byproduct Profit per Mcf Produced
1955	0.105	0.075	0.114	-0.065
1956	0.251	0.073	0.081	-0.243
1957	1.097	0.087	0.100	-1.084
1958	0.526	0.090	0.077	-0.539
1959	0.113	0.096	0.091	-0.117
1960	0.117	0.083	0.115	-0.084
1961	0.295	0.105	0.116	-0.284
1962	0.087	0.108	0.148	-0.048
1963	0.140	0.104	0.240	-0.004
1964	0.048	0.105	0.262	0.109
1965	0.133	0.088	0.289	0.068
1966	0.116	0.095	0.328	0.118
1967	0.300	0.108	0.369	-0.039
1968	0.226	0.098	0.348	0.024
1969	0.140	0.090	0.289	0.058
1970	0.429	0.091	0.236	-0.285
1971	0.920	0.104	0.240	-0.783
1972	0.392	0.107	0.256	-0.244
1973	0.181	0.102	0.313	0.030
1974	0.245	0.110	0.545	0.190
1975	0.154	0.128	0.602	0.320
1976	0.263	0.139	0.567	0.164
1977	0.171	0.146	0.601	0.283
1978	0.218	0.152	0.557	0.187
1979	0.232	0.143	0.564	0.188
1980	0.405	0.160	0.760	0.195
1981	0.233	0.168	0.874	0.473
1982	0.677	0.173	0.839	-0.011
1983	0.210	0.201	0.929	0.519

Sulfur

It has already been noted that operating costs for a field are two-thirds higher for sour gas than for sweet gas.[29] Using what was described as "standard" costs for a sour gas processing plant,[30] one finds that capital costs come to an equivalent of over $1 per Mcf produced. (The High River plant is closer to 90 cents per Mcf.) As it happens, the value of the sulfur comes to 25 cents per Mcf of the resulting "dry" gas (using $60 per tonne of sulfur), while the NGL yields $4.50. Similarly, for the Moose and Whiskey fields, which will send their gas to the Quirk field processing plant, the cost for a completely new plant was put at $50 million, but no throughput figure is available yet.[31]

The large sulfur inventory in Canada is the other side of sulfur production. By the end of 1984, it stood at slightly more than two years of production, after declining from a level equal to over three years of production in the late 1970s. Prices had weakened, but by mid-1985 they were double what they had been at the end of 1983, and anticipated sales for 1985 are 50% higher than production, which should consume one quarter of the existing inventory.[32] However, most production still must be held as

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[29] According to Bradley (1984), p. A19.

[30] **Oilweek**, 9/5/83, suggested that the Brazeau River plant would cost $35 million (presumably US), although subsequently, the **Oil & Gas Journal** of 10/29/84 put the cost at $43.2 million. We use the former number since it was an estimate reflecting typical costs, rather than the actual costs cited for that specific field, as the latter is. The sour gas processing plant at the High River field, handling 60 mcf/d, costs $100 million, according to the same **OGJ**, yielding similar cost curves, though no NGL yield is mentioned.

[31] **Oilweek,** 1/30/84.

[32] See **Oilweek**, "Mid-Year Forecast and Review," 7/22/85, pp. 14-16. The prices are the producers' netback.

inventory, such that the holding costs reduce the value noticeably. In the early 1980s, holding costs would have been significant. The same is definitely not true of NGLs.

From In-Ground Cost to Above-Ground Cost

As explained earlier, a gas producer will lose money if he sells the gas at less than its investment cost plus some allowance for holding the asset while it is gradually depleted. The derivation of the "present Mcf factor" is explained in Appendix A. It is equal to $[1+(i/a)]$, where i is the risk-adjusted interest rate and **a** is the decline rate, which we approximate by using the depletion rate, or ratio of current output to current proved reserves.

Two measurement problems are involved here, and a comparison of Table 4-a with Table 4-b shows their importance. But both of them are also problems of public policy.

The discount rate i is measured in two ways. The first is by using the **nominal** rate for a Canadian producer. We take the riskless rate, Canadian Treasury bills, and add an 8 percent premium for industry risk. This is standard procedure, and is supported by the DataMetrics calculation of real discount rates in Canadian oil and gas.[33] The effect of expected inflation here is very powerful. As recently as 1983, a Canadian producer spending 20 cents to develop an Mcf of gas in the ground needed a price of $1.30 at the time of sale to allow for very high holding costs, because of expected inflation.

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[33] DataMetrics Ltd., **The Oil & Gas Investment Climate: Changes over a Decade**, Canadian Energy Research Institute, Study No. 20, June 1984.

The second discount rate measure in effect by-passes the entire inflation issue by using a real rate of 10 percent, applied to constant dollar results. In 1983, an in-ground cost of 16.4 cents corresponds to an above-ground value of 68 cents, which is barely half of the inflation-affected cost estimate. This comparison shows the pernicious effect of expected inflation in repressing investment. It is certainly more hopeful to use the real discount rate, but it is only realistic if we suppose that inflation has been brought under control, or that the nominal price of natural gas will rise about as fast as the general price level.

We turn now to the other determinant of above-ground value, the decline/depletion rate. To some extent, this is strictly reservoir engineering: the additional investment needed to speed up depletion, within a limit. At some point, faster depletion would damage the reservoir, and reduce ultimate recovery so that it would not pay.

But to some extent, it is also public policy. If there must be a 25-year reserve backup to any contract, this in effect lowers the value of the depletion/decline rate _a_ to the neighborhood of 4 percent. (See Table 11). This is a fairly substantial increase in cost. With both the discount rate and the decline/depletion rate at about 10 percent, the factor $[1+(a/i)]$ is equal to 2. With _a_ restrained to .032, the factor is over 4.

This increase is moderated to some degree because higher depletion rates require more wells drilled and more above-ground installations, hence more investment. In general, there is a tradeoff between higher investment per unit of output, and greater present value because of faster recovery. Over a certain range, the operator gains economies of scale, because of indivisibilities (e.g., access roads). At some point, faster depletion calls for

TABLE 11
Canadian Natural Gas Depletion Ratio

	Proved Reserves Yearly average (tcf)	Productio (tcf)	Depletion Rate
1955	13.6	0.145	0.011
1956	16.0	0.192	0.012
1957	17.7	0.242	0.014
1958	19.4	0.333	0.017
1959	22.0	0.436	0.020
1960	25.2	0.472	0.019
1961	28.3	0.690	0.024
1962	30.4	0.831	0.027
1963	32.1	0.899	0.028
1964	36.2	1.004	0.028
1965	39.8	1.082	0.027
1966	41.9	1.119	0.027
1967	44.6	1.209	0.027
1968	46.7	1.387	0.030
1969	49.8	1.548	0.031
1970	52.7	1.789	0.034
1971	54.4	1.942	0.036
1972	54.2	2.236	0.041
1973	52.7	2.313	0.044
1974	49.6	2.380	0.048
1975	51.8	2.348	0.045
1976	57.6	2.527	0.044
1977	58.9	2.479	0.042
1978	60.9	2.328	0.038
1979	64.6	2.617	0.040
1980	66.9	2.472	0.037
1981	67.8	2.392	0.035
1982	69.1	2.453	0.035
1983	69.8	2.214	0.032

Source: Canadian Petroleum Association, Statistical Handbook. Post 1978 proved reserves are set equal to .76 of established reserves.

disproportionately large incremental investment, or additional output would damage the reservoir and reduce ultimate recovery and present value.

However, when depletion rates are constrained by law, or by unexpectedly low demand, there are no compensations, and costs rise steeply. There is a hopeful aspect to this. If Canadian markets can be expanded, then the depletion rate can be drastically raised with little additional investment, and costs brought down substantially.

In fact, there appears to be a difference between the depletion rate for Canada (or Alberta) and that for a given field. In estimating the depletion rate, we have corrected the data for "established" reserves (roughly, proved plus probable), using the ratio for the most recent observations (i.e., the late 1970s). If "established" reserves were employed as reported, the depletion rate would be much smaller and the above-ground costs much higher, but this would be misleading, since much of "established" reserves have not actually been developed.[34]

For actual, developed fields, a 5% decline rate appears to be the norm.[35] Thus, the present Mcf factor would be 3, which is close to the observed value for the 1970s, when data on "proved" reserves were still available. Since the measured decline rate (and estimated present Mcf factor) increases after 1978, the last year when proved reserves were reported, this suggests that either our correction to proved reserves is inaccurate, or the weak market has led to underproduction at developed fields, or conceivably both. The first possibility means that above-ground

[34] However, note that the 25-year provision in Canadian export policy refers to "established" reserves.

[35] Private discussions with industry officials.

costs experienced by field operators is less than our estimate, while the second suggests that it is inflated by market conditions, and should come down as they improve.

To get some approximation of the sum of finding plus development cost, we can raise the hypothetical hurdle of minimum rate of return on development investment. This would embody the assumption that using up the known undeveloped reservoir comes at the cost of finding, at greater risk, a reservoir to replace it. The higher the risk is, of course, the greater the inducement to invest in exploration in order to be able to develop.

For fields already known, of course, development cost is all we need consider.

Supply Cost Trends in North America

In trying to estimate the long-run costs of natural gas supply in North America, enormous obstacles must be overcome. Regulatory policy, such as price controls, and market disturbances, such as the oil price shocks, have introduced serious perturbations. This is especially true since natural gas is often found by companies searching for oil, so the intent of exploration cannot be divined. Thus, the exploratory response to the price of natural gas cannot be adequately measured. Combined with the paucity of data, the resulting cost estimates are uncertain at best, and future trends are difficult to read.

Still, analysis is not entirely fruitless. Working with data provided by the U.S. Census Bureau and the Canadian Petroleum Association, historical costs can be examined. The following sections will discuss possible future cost trends, in particular the transient effects of policy, the short-term effects of the recent market difficulties, and the long-term effects of physical deterioration of the resource base due to continuing exploitation.

Transient Factors

Two types of transient factors have impacted on the supply of natural gas in North America during the last decade: policy and market. For the former, the Natural Gas Policy Act of 1978 (NGPA) in the United States has caused severe dislocations and created great uncertainty for producers, making market trends difficult to read. In Canada, the policies of past administrations, particularly those reflecting the belief that gas resources could only appreciate in value, have had similar effects. The transient market impact stems largely from the existence of a glut in drilling rigs, shut-in wells, and other similar problems that should pass as the market moves back toward equilibrium. The question for observers is: When this will occur and where will the long-term supply curve be?

A mixture of misinterpretation of market signals and poor policy directions resulted in large-scale disruption of natural gas exploration. In the United States, higher prices were provided for expensive gas, such as deep gas, to encourage development of this particular resource. This policy, more than the deterioration of the resource base, led to much of the cost escalation described earlier. Deep drilling in the United States declined 45 percent from 1982 to 1983, while total drilling only fell 12 percent.[36]

At the same time, the spike in price expectations led to an enormous

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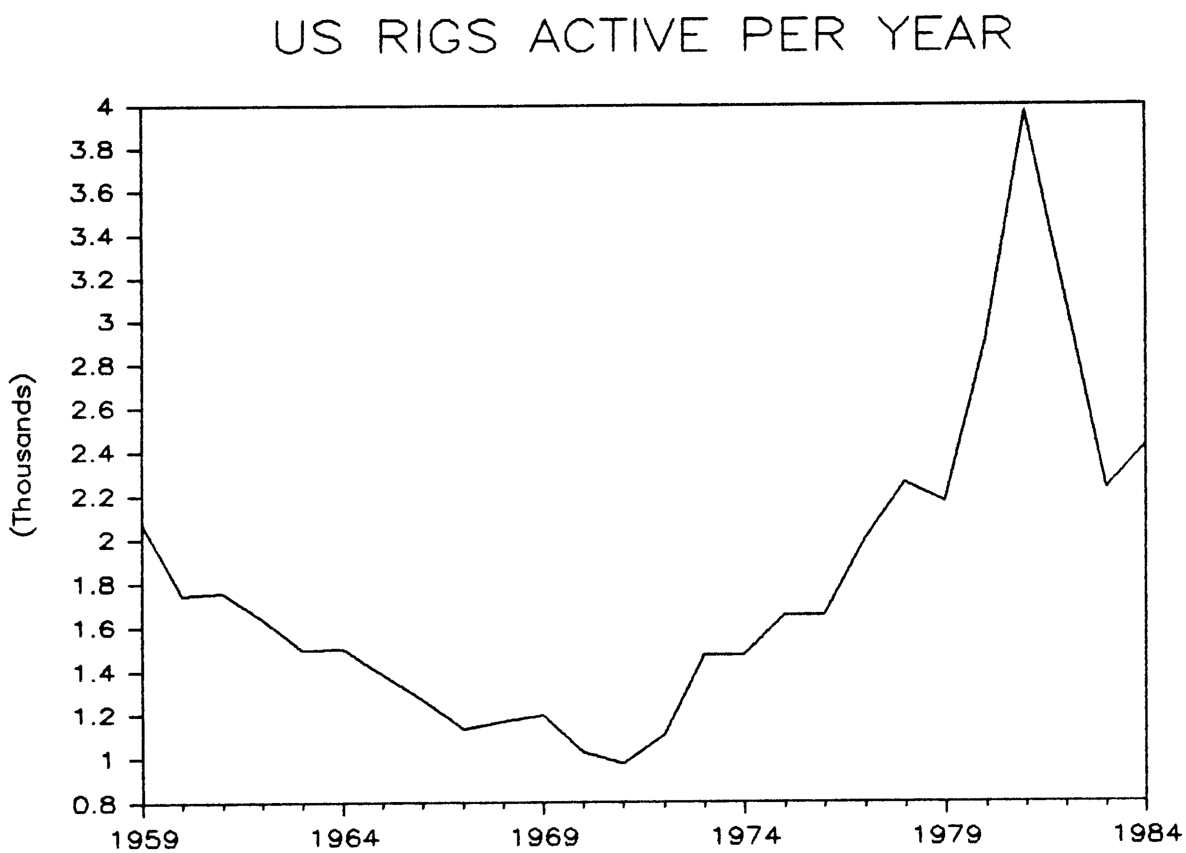
[36] **Joint Association Survey on Drilling Costs**. "Deep" is defined here as any well below 15,000 feet.

Figure 7



Source: Monthly Energy Review, DOE.

increase in the demand for drilling rigs. As Figure 7 shows, the number of rigs in service boomed after the Iranian Oil Crisis, resulting in major productivity losses. To a very real degree, the economic rents available due to higher prices were captured by drilling contractors, oil country tubular goods manufacturers, and labor.

Short-term factors do not last, by definition. As Table 12 shows, rig efficiency has soared and drilling costs have plummetted. The question is: Has the industry overshot? Factor prices now seem to reflect little more than operating costs on existing rigs that desperate contractors are seeking to keep active to provide themselves with cash flow. Will costs soar after idle rigs in the parking lots of banks all over the Southwest rust out? Or have we, effectively, reached the new equilibrium?

These are questions that will only be answered toward the end of the decade, if then. However, the salient fact is that the new "lower" costs are actually strongly similar to those just prior to the Iranian Oil Crisis, the NGPA and the drilling boom. If capital costs are not being covered for rigs purchased in 1980, this does not prove that "replacement costs" of equipment must inexorably drive prices higher when equipment finally needs to be replaced, since much of that equipment was purchased at extremely high interest rates and for exorbitant prices. Exploratory wells continued to be drilled at high levels, despite all the talk of falling investment, with new field wildcats in the United States up 5 percent in the first half of 1985.[37] In 1984, a preliminary estimate made by the American Gas Association based on additions to reserves by the major companies, puts U.S. additions to

[37] **International Gas Technology Highlights**, 7/22/85, reporting data from Petroleum Information Corporation.

TABLE 12
INDICATORS OF GAS DEVELOPMENT COST

	1982	1983	1984	1985 (Jan-May)
Wells completed per year, all types (000s)	85.8	76.3	74.4	85.8
Rigs active	3105	2232	2428	2076
Wells/Rig Year	27.6	34.2	30.6	41.3
Gas wells/yr (000s)	18.95	15.63	15.1	17.38
Gas Cost Proxy (GW/(W/RY))	0.69	0.46	0.49	0.42
Reserve-adds (tcf)	15.1	14.8	17.5	NA
Cost, Proxy units per tcf	0.045	0.031	0.028	NA
Cost/tcf, index	1.000	0.680	0.620	NA

Sources: Monthly Energy Review,
Reserves Additions from EIA,
except for 1984, from AGA.

reserves at 17.5 Tcf, versus 14.9 in 1983.[38]

In Canada, the transient factors are somewhat different. Higher prices did encourage drilling in high-cost areas such as the Foothills, and interest there seems to be waning, with lease acquisition costs per hectare falling nearly 60 percent between 1984 and 1985, versus an average decline of 16 percent.[39] On the other hand, the Petroleum Incentive Program has continued to keep exploration high in frontier areas, especially given the grandfather clause for ongoing programs. Although future exploration should be lower, it seems that this is partly due to a shift to development of discovered fields.[40] In addition, the emphasis in Canada now is on oil drilling, as relaxed investment criteria, the decontrol of oil prices, and easier export of production have enhanced its value relative to natural gas.

At the same time, there is still substantial room for Canadian supply costs to fall, depending on both market factors and policy actions. Wells per rig year fell dramatically in 1979 and 1980, but have nearly doubled since, increasing again last year despite a 38% increase in the number of wells drilled.[41] (See Figure 8.) Long lead times, due to both regulatory and market factors and low utilization levels, have helped increase costs beyond what a competitive market would bring, and some relief appears likely under the new government. Additionally, a lowering of factor costs in the

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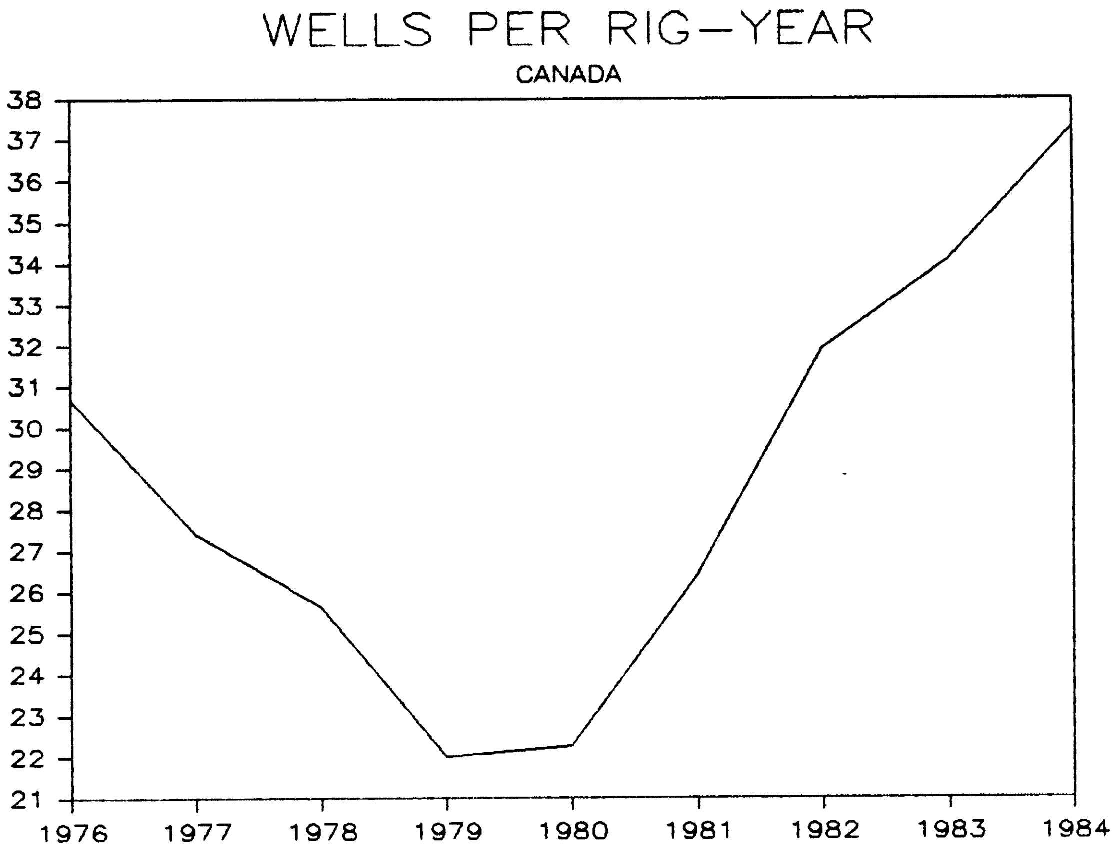
[38]"Preliminary Findings Concerning 1984 Natural Gas Reserves," American Gas Association, 5/3/85.

[39]**Oilweek**, 7/22/85.

[40]See, for example, **Oil and Gas Journal**, "North American Arctic Report," 8/5/85.

[41]Reported by the American Association of Petroleum Geologists, in **International Gas Technology Highlights**, 8/5/85.

Figure 8



Source: International Petroleum Encyclopedia 1984, Pennwell; Hughes Tool Co.; and Statistical Handbook, Canadian Petroleum Association.

United States should be felt in Canada, depending of course on exchange rate behavior.

Trends in Long-Term Supply Costs

Obviously, policy plays a major role in determining the costs of natural gas supply in the short and even medium term. But over long periods, the resource base and the technology of extraction are the main determinants. As is often discussed, the nature of mineral extraction is such that the "best" (i.e., cheapest), deposits are found first. As time passes and exploitation increases, smaller and deeper deposits are hunted. However, advancing knowledge, both in terms of geology and technology, offsets this. The question is: How do advancing knowledge and encroaching physical deterioration interact?

The most easily observed evidence of the depletion of resources is the move to fields that are: (a) smaller, (b) deeper, and (c) more difficult to access. Other factors, such as the degree of difficulty involved in exploiting a particular geology, are more difficult to observe on a national level.

The average size of U.S. fields has declined, as can be seen in Table 13, but this has been offset by the move to larger but less accessible fields, i.e., offshore or in Alaska. Certainly, the average production per well has declined over time, although the previous caution about policy impacts must be reiterated.

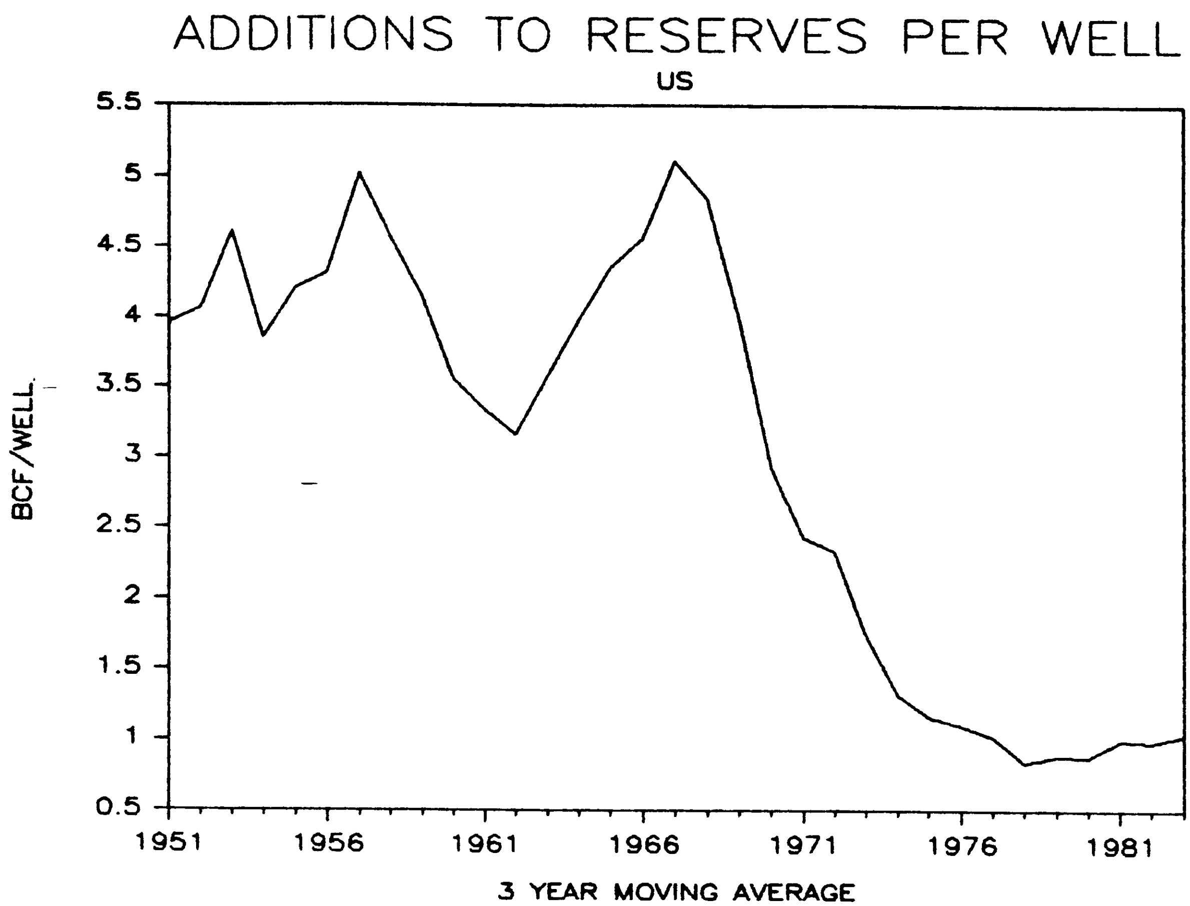
The impact of size is more clearly evidenced by the return to drilling, which is illustrated by Figure 9, showing total additions to reserves per completed gas well in the United States (i.e., not including dry holes, test

TABLE 13
US FIELD SIZE
(natural gas)

	Total Fields Discovered	Total Fields Discovered of Significant Size	Percent of Significant Gas Fields in all Gas Discoveries	Percent of Significant Gas Finds in Total New-Field Wildcats Drilled
1945	93	49	52.7%	1.69
1946	73	32	43.8%	1.07
1947	98	44	44.9%	1.32
1948	100	46	46.0%	1.13
1949	112	57	50.9%	1.34
1950	107	44	41.1%	0.85
1951	138	65	47.1%	1.08
1952	148	68	45.9%	1.06
1953	159	52	32.7%	0.78
1954	211	68	32.2%	0.97
1955	200	50	25.0%	0.63
1956	181	63	34.8%	0.75
1957	234	99	42.3%	1.31
1958	241	73	30.3%	1.1
1959	225	62	27.6%	0.88
1960	237	80	33.8%	1.09
1961	242	46	19.0%	0.66
1962	292	79	27.1%	1.16
1963	215	50	23.3%	0.76
1964	226	53	23.5%	0.8
1965	224	52	23.2%	0.84
1966	201	47	23.4%	0.76
1967	164	41	25.0%	0.78
1968	137	40	29.2%	0.77
1969	174	44	25.3%	0.74
1970	130	37	28.5%	0.72
1971	160	46	28.8%	1.03
1972	245	58	23.7%	1.14
1973	359	75	20.9%	1.5
1974	398	69	17.3%	1.04
1975	404	68	16.8%	1.11
1976	506	63	12.5%	1.08
1977	462	81	17.5%	1.33

Source: "North American Drilling Activity," AAPG Bulletin.
"Significant" is defined as greater than 6 Bcf.

Figure 9



Note: Wells included are exploratory and development gas wells.

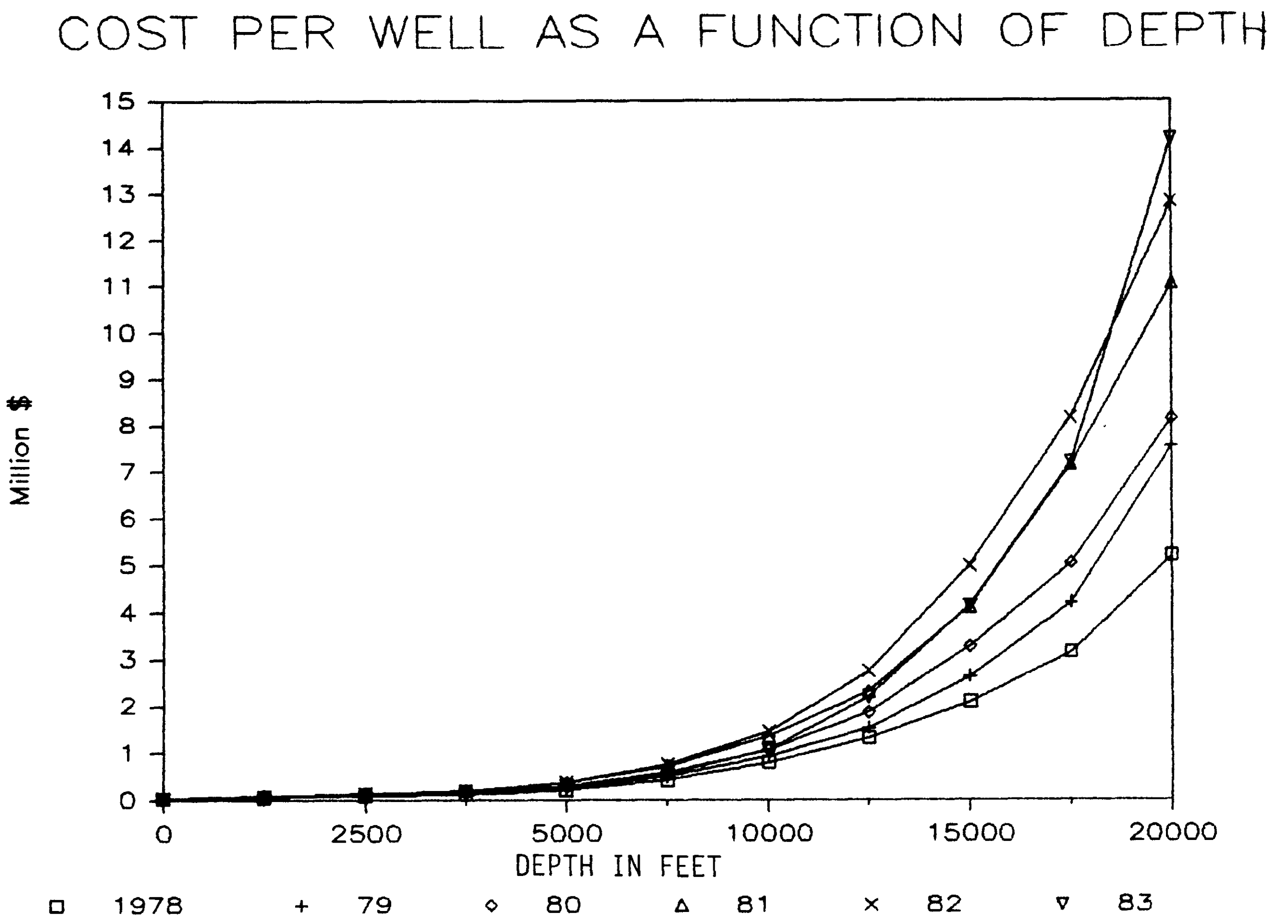
wells, etc.). From 1949 until the mid-1960s, the return to drilling fluctuated over a large range, around a mean of about 4 Bcf per well. However, from the mid-1960s until the early 1970s, a precipitous drop occurred, levelling off from 1973 until 1983 (the latest data available). Naturally, given the nature of exploration, a large variance should be expected in returns from year to year; however, the paradigm of gradual long-term decline is not a good fit to the actual data. (See Figure 9.) What is needed is an understanding of the countertrends that produced periods of stability of return to drilling.

The two most obvious factors are advances in technology, which allow drilling in areas previously inaccessible, and access to regions that had been previously restricted. Most especially, the move into offshore waters and the drilling of deep basins has probably served to offset the decline in return to drilling in more conventional areas, the former affecting returns in the 1950s, and the latter coming into play during the 1970s.

The depth of the resource being exploited is very important, because drilling costs increase exponentially with depth, as can be seen in Figure 10. However, save for the mid-1960s, the average depth of exploratory gas wells, shown in Figure 11, has not increased significantly. For development wells, a different story is apparent in Figure 12, where a sharp increase from the late 1940s to the early 1960s can be seen. (The disparity between exploration and development reflects the lag time between the two. Figure 12 shows the depth for all wells; but for producing wells, development wells greatly outnumber exploratory wells.)

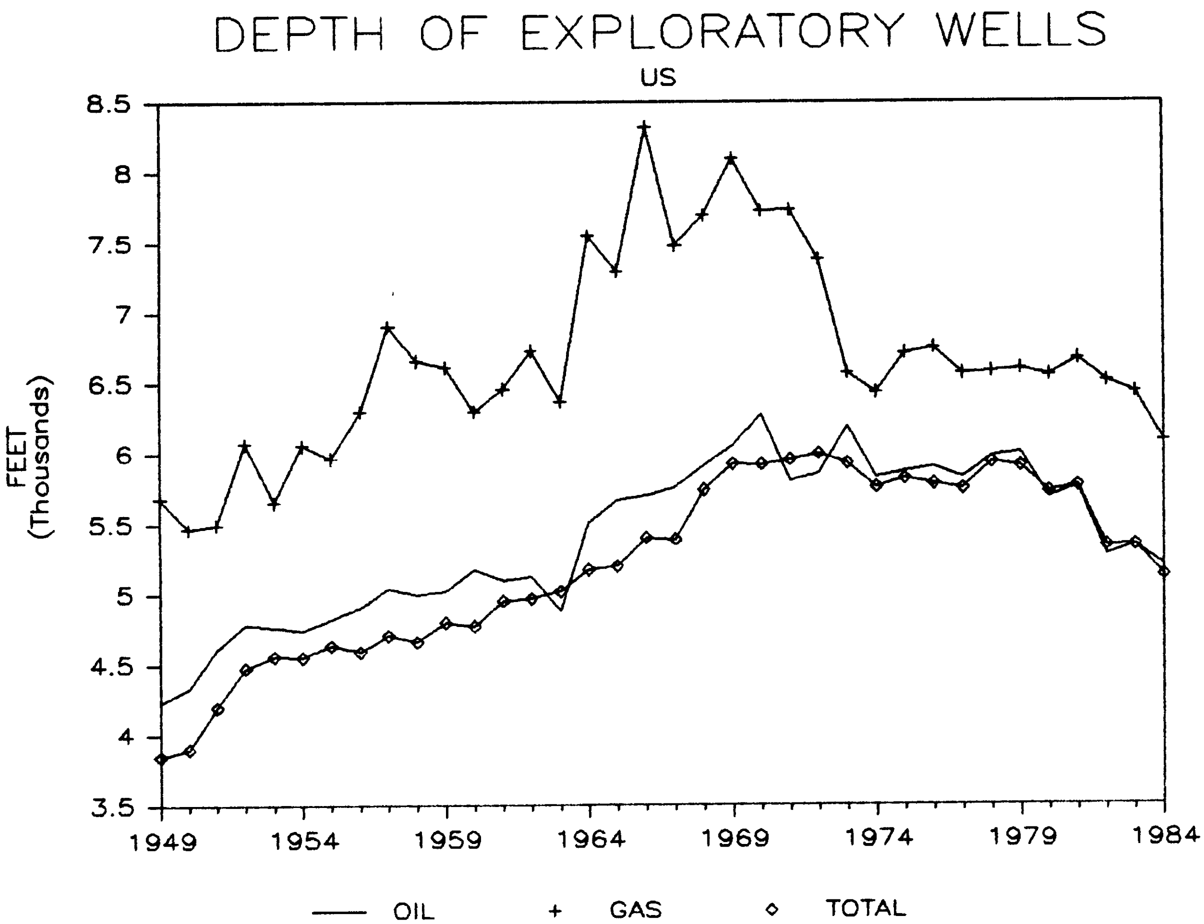
Returns to drilling also reflect the percentage of wells that strike natural gas, which has increased in the last decade. (See Figure 13.) Of

Figure 10



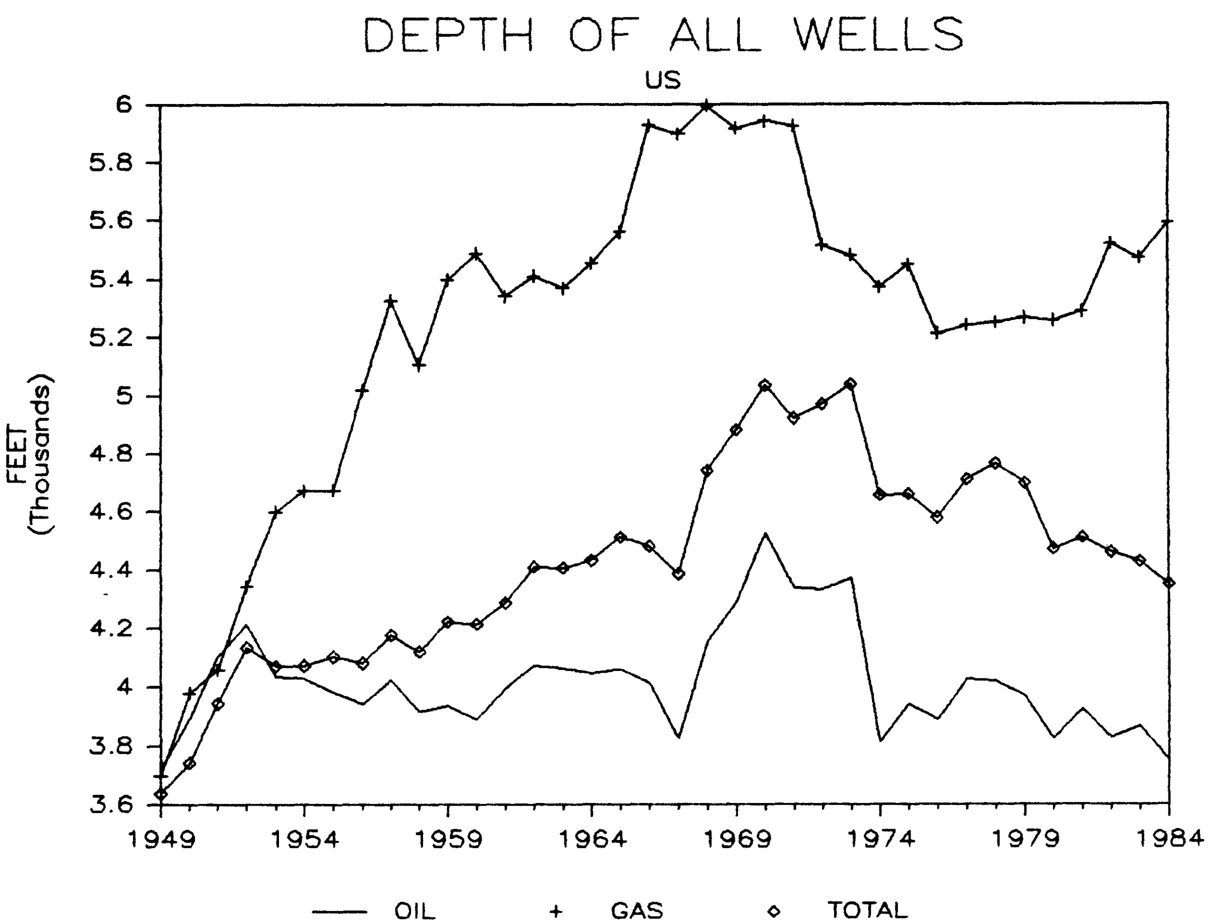
Source: Joint Association Survey on Drilling Costs, American Petroleum Institute.

Figure 11



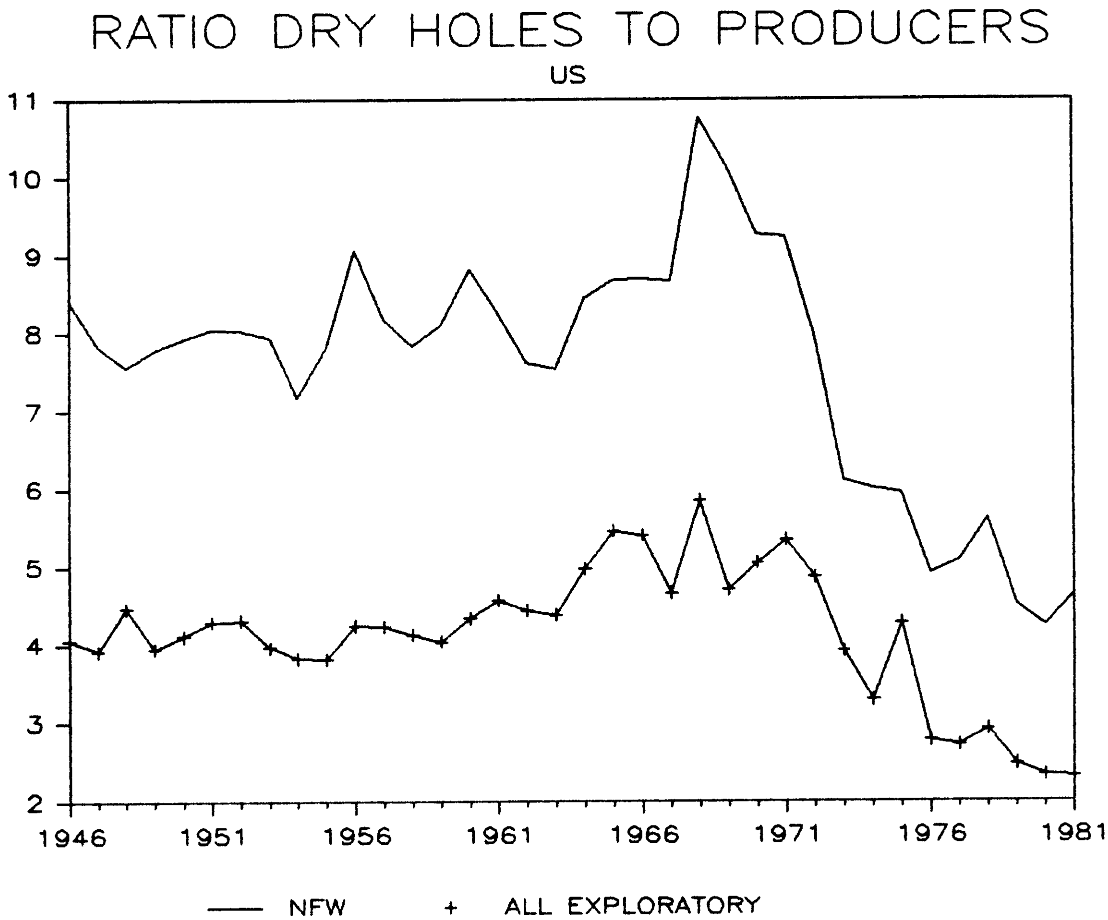
Source: Twentieth Century Petroleum Statistics, DeGolyer and MacNaughton.

Figure 12



Source: Twentieth Century Petroleum Statistics, DeGolyer and MacNaughton.

Figure 13



NFW = New Field Wildcats

Source: "North American Drilling Activity," <u>AAPG Bulletin</u>, American Association of Petroleum Geologists.

course, the measure of reserve additions per well does not include dry holes, but in fact the higher prices of the late 1970s turned many poor producers from uneconomic to performers, creating a bias for lower returns to wells.

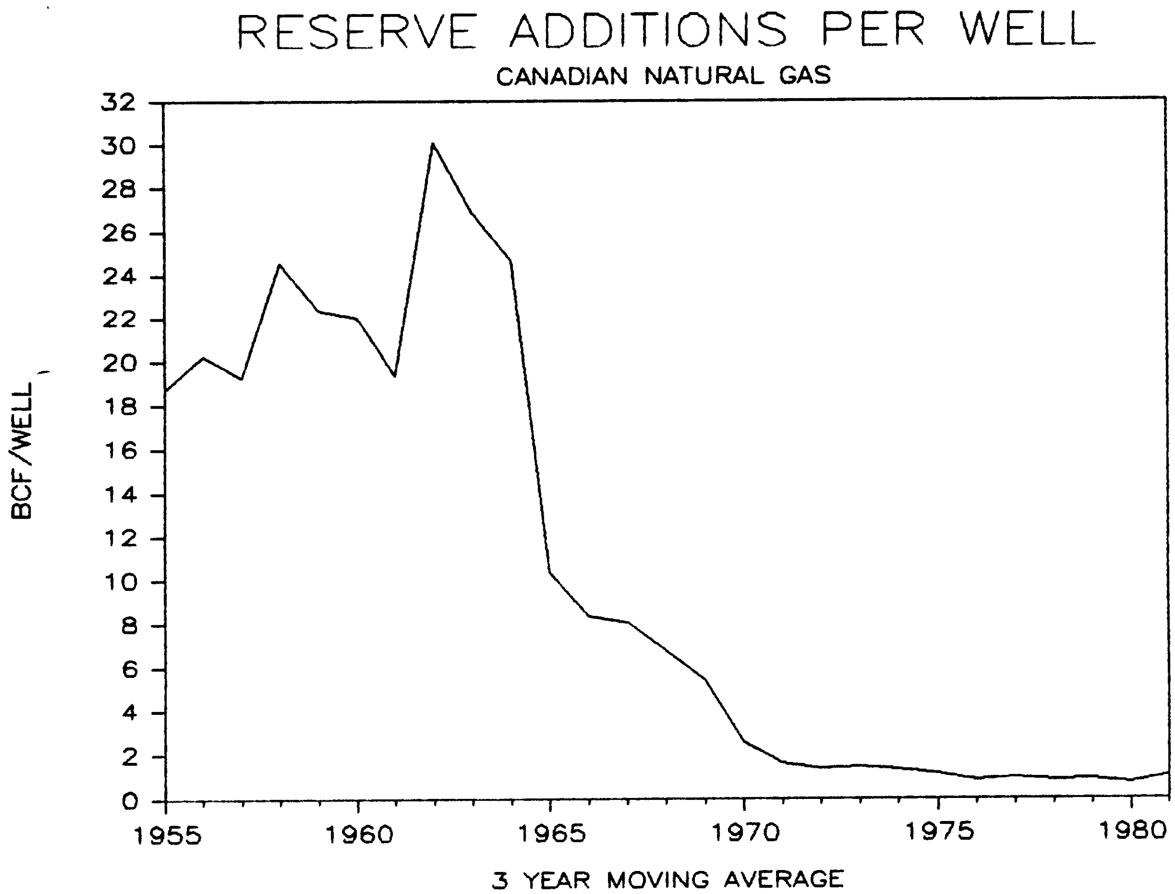
In Canada, the period of exploitation has been much shorter, but at the same time the Western Sedimentary Basin is often described as being in a "mature" phase. To the extent that this means that field size and variance have dropped, we agree. As Figure 14 indicates, the decline rate on return to drilling has become quite steady, somewhere on the order of 3 percent per year. Exploratory well depth, shown in Figure 15, has increased recently, but only back to the level of the mid-1950s, and this is probably due to a surge in drilling for deep gas, which should abate in the weaker market.

Changes in Finding-Development Cost Since 1973

There should be universal agreement that finding and development costs have increased in the United States (and Canada) since 1973, but it is impossible to be any more precise.

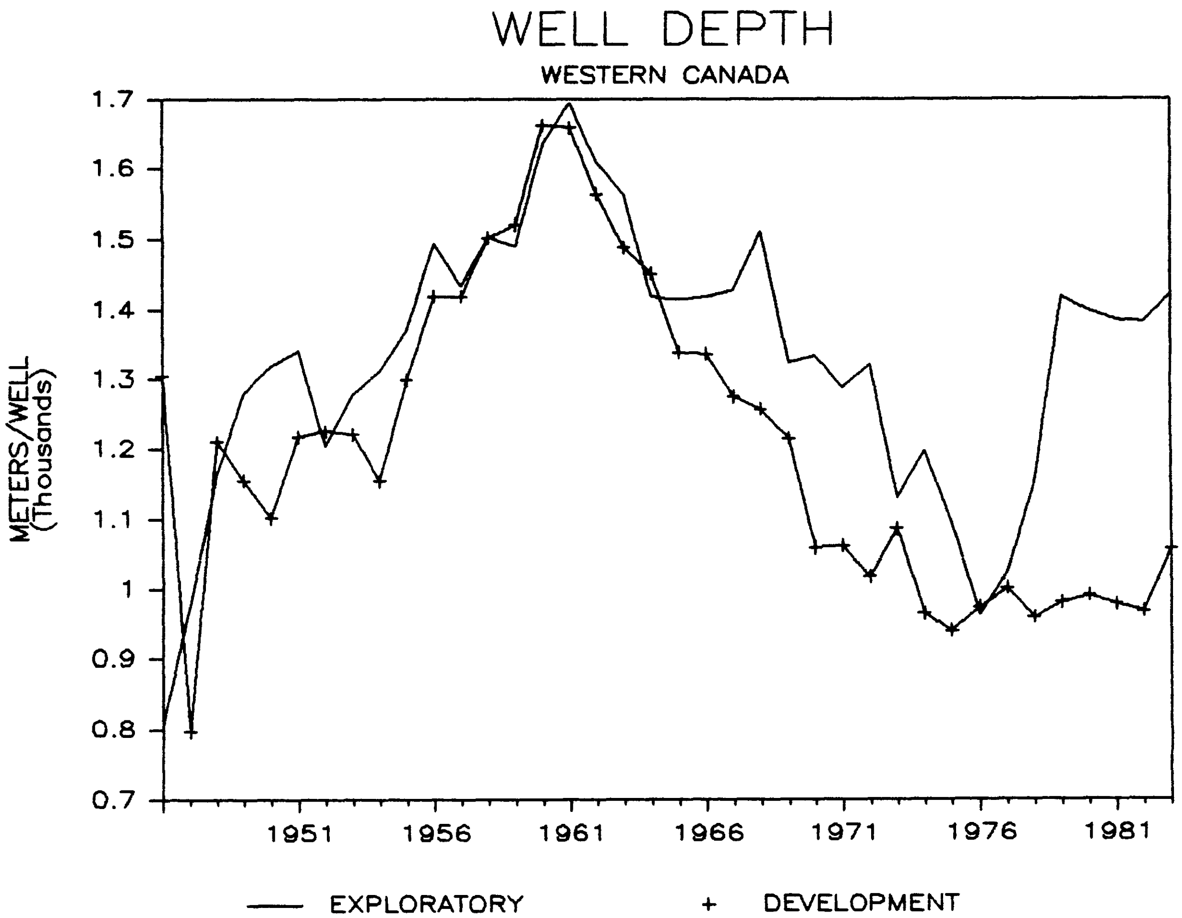
First, it is literally impossible to make any estimate of trends in finding costs. While there are reasonably good data on expenditures for finding and for developing, there are literally no data in the United States on amounts newly discovered since 1973. The so-called "discoveries" in the U.S. statistics refer only to the initial year estimates, which are only a minor proportion (roughly a fifth) of the eventual estimates. Furthermore, it takes about six years before plausible retrospective estimates can be made, using information obtained by development after discovery. Unfortunately, in the United States the last year in which retrospective estimates of discoveries were published, both for oil and gas, was 1979. Hence, the

Figure 14



Source: Statistical Handbook, Canadian Petroleum Association.

Figure 15



Source: "North American Drilling Activity," AAPG Bulletin.

last year for which we have acceptable discoveries estimated in the United States is 1973.

Reserves-added by development, however, continue to be available on an annual basis. This includes all such reserves, including "discoveries", which are reserves newly developed out of new fields, as distinguished from reserves newly developed out of old fields.

In Table 14, we calculate development outlays as compiled by the Census Bureau, from a series that unfortunately ended in 1983; we extrapolate by the change in expenditures on development wells, from a Joint Association Survey. These are divided by the oil-equivalent of crude oil, natural gas, and natural gas liquids reserves added each year. The resulting nominal cost per barrel is then divided by the IPAA index of drilling costs to yield a constant-dollar development cost per barrel of oil equivalent.

This series was affected by powerful turbulence in 1973-83. There were considerable fluctuations in reserves-added per year, though the lumping together of liquids and gas tends to smooth them out. There were also great inefficiencies as drilling expanded in response to higher prices. After 1982, efficiency improved greatly. These fluctuations mask the underlying increase in costs imposed by resource depletion.

Constant-dollar development cost by dollar per barrel of oil equivalent more than doubled in only three years, from 1973 to 1976. Then it fell dramatically, so by 1980 it was only 35 percent higher. Then it went through a rapid three-year cycle and ended up where it had started, at 32 percent above 1973. A least-squares estimate of the average annual percent increase would be about 4 percent. Finding costs must have been increasing at a similar rate, because development and discovery are substitutes.

TABLE 14
CALCULATION OF CONSTANT DOLLAR DEVELOPMENT COST PER BARREL
U.S. 1973-1983

Year	Development Outlays $Millions ASOG (net)	Development Outlays $Millions ASOG (gross)	Gross Reserve Additions MM BOE (API-AGA)	Gross Reserve Additions MM BOE (EIA)	Development Cost per Barrel oil Equivalent	IPAA Index of Drilling Costs (1972=100)	Constant Dollar Development Cost per BOE (1972 $)
1973	2856	3369	3732		0.90	103	0.87
1974	3939	4742	4110		1.15	124	0.92
1975	6120	7207	3745		1.92	144	1.33
1976	7354	9119	3223		2.83	158	1.79
1977	8895	9995	3738	n.a.	2.67	172	1.56
1978	10562	12462	3768	6502	2.43	192	1.27
1979	11793	14186	5059	4087	3.10	211	1.47
1980	16164	19283		6697	2.88	245	1.18
1981	24043	31999		7349	4.35	285	1.53
1982	24347	33432		5239	6.38	303	2.10
1983	n.a.	22206		6806	3.26	284	1.15
1984	n.a.	n.a.		6750		279	

Sources:

1) Development costs, net, from Bureau of the Census, "Annual Survey of Oil & Gas," annual. Excludes purchase of productive acreage.
2) Development costs, gross, from ASOG, multiplying net by ratio of gross to net outlays on development. N.B. 1977 values based on revised number in 1978 issue. For 1983, estimated from 1983/82 ratio of outlays on development wells, from "Joint Association Survey on Drilling Costs," API and AGA.
3) Gross reserve additions 1974-1977, from "Reserves of Crude Oil Natural Gas Liquids, and Natural Gas in United States and Canada and United States Productive Capacity," API, AGA, and CPA. Annual. Gas converted at 5.8 Mcf per barrel.
4) Gross reserve additions 1980-1984 from Energy Information Administration, "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids," annual. Gas converted at 5.8 Mcf per barrel.
5) Gross reserve additions 1978-1979 arithmetic average of API-AGA-CPA and EIA.
6) Development per barrel equals development cost, gross, divided by gross reserve additions.
7) IPAA drilling cost index from annual reporst of Cost Study Committee. Unadjusted for well distribution.

Long-Term Forecasts

Although energy forecasting has built up quite a poor reputation in recent years, it is considered a necessary evil, mostly by government and industry research groups. Thus, forecasts play a serious role in policy formation, often excessively so, considering the quality of the analysis, the biases that occur, and the uncertainties involved. Before discussing our expectations for long-term natural gas supply in North America, a brief review of the most current "official" forecasts will be presented.

United States

The "conventional wisdom" is that the current glut in U.S. natural gas will last for several more years, followed by lower production and higher prices. Table 15 shows a number of natural gas price and supply forecasts for 1990, most of which indicate no change in prices, but slightly lower production. However, as Figures 16 and 17 show, this trend is expected to change in the 1990s, at least by DOE and GRI, with rapidly falling production and increasing prices. This fits in with most "experts'" expectations for oil prices until the end of the century.

These projections illustrate the difficulties of long-term forecasting. In order to understand supply (and demand) beyond the current decade, the impact of increasing knowledge must be assessed, and this task is very difficult. To avoid this problem, most forecasters begin by analyzing only what will be available with current technology. In other words, if tight gas can only be produced at $8/Mcf today, assume that the cost will remain constant, or the resource unavailable.

By this measure, roughly one-third of current world oil production and

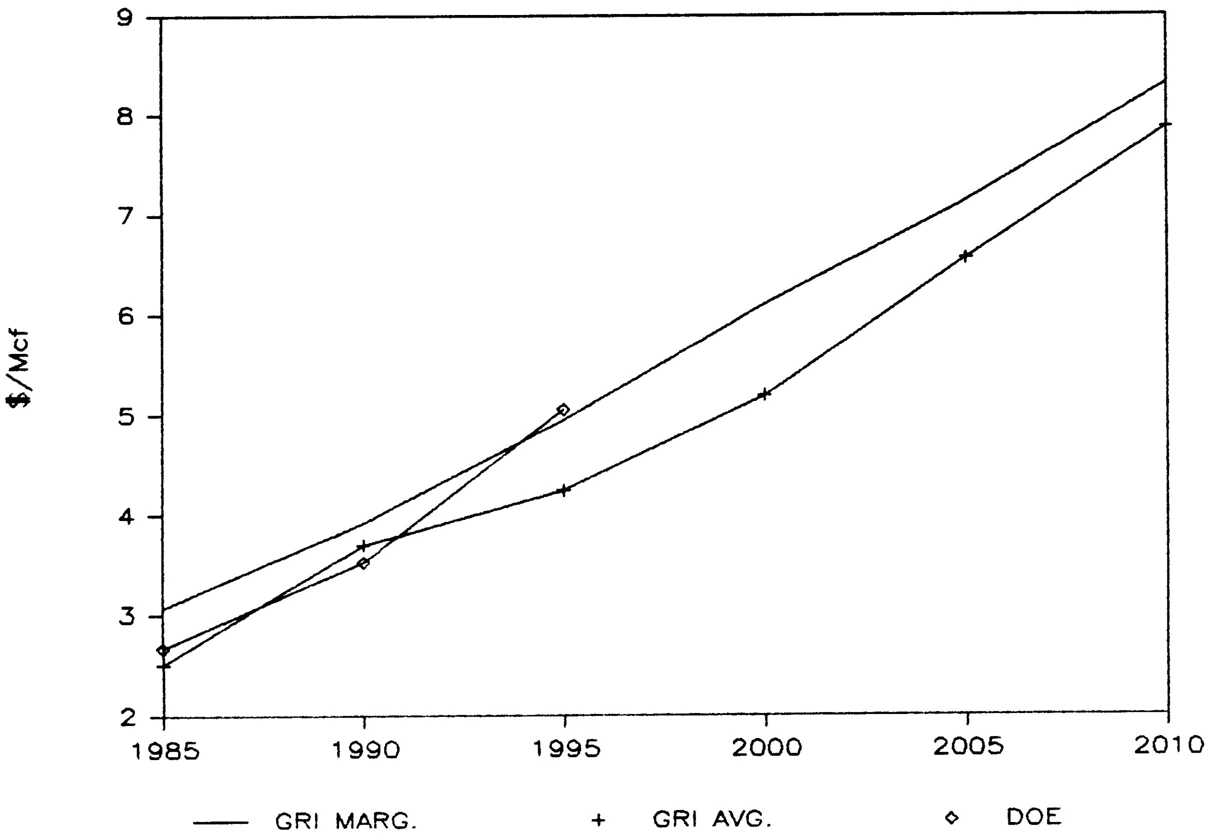
TABLE 15
NATURAL GAS FORECASTS FOR 1990

	Price ($/Mcf)	Production (Tcf)
AEO 1984	3.52	17.3
DRI	2.69	16.4
Chase	2.73	16.7
GRI	3.70	17.7
Merrill Lynch	2.83	18.9
AGA	na	19.3-21.0

Source: Annual Energy Outlook, 1984, DOE, p. 191. For DRI and GRI, price is pipeline acquisition cost minus $0.32, the differential between it and wellhead price in 1983.

Figure 16

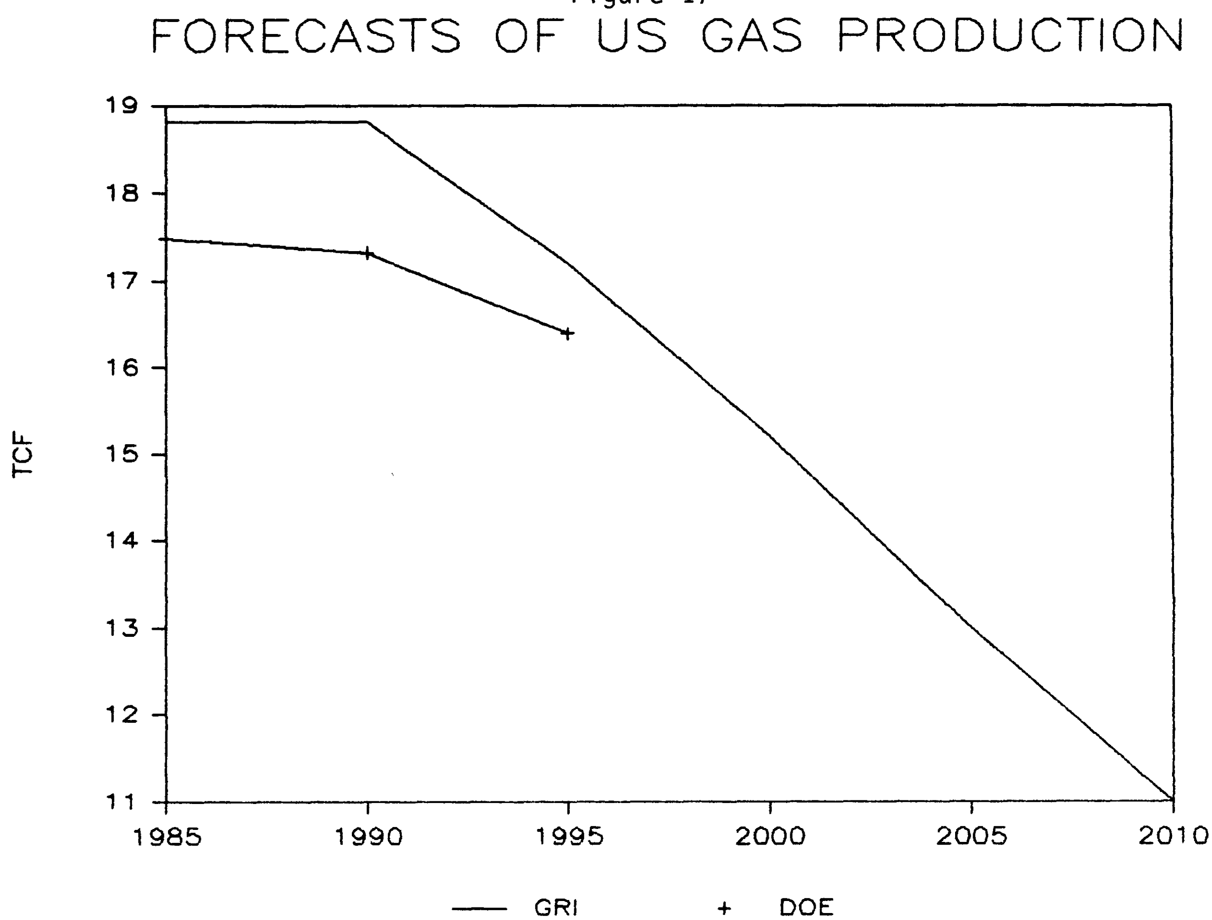
FORECASTS OF US GAS PRICES



GRI MARG = GRI forecast of marginal prices
GRI AVG = GRI forecast of average prices

Sources: Annual Energy Outlook, 1984, U.S. DOE; "The Long-Term Trends in Lower-48 Gas Supply and Prices: The 1984 GRI Baseline Projection of U.S. Energy Supply and Demand, 1983-2010," Thomas J. Woods, February 1985.

Figure 17



Sources: Annual Energy Outlook, 1984, U.S. DOE; "The Long-Term Trends in Lower-48 Gas Supply and Prices: The 1984 GRI Baseline Projection of U.S. Energy Supply and Demand, 1983-2010," Thomas J. Woods, February, 1985.

one-fifth of natural gas production would have been defined as "unconventional" 35 years ago.[42] The technology to produce oil and gas from offshore waters did not exist then, and these resources would not have been included in any assessment of future supply. Considering that during most of the intervening period, real prices for hydrocarbon fuels were **falling**, it is clear that technological advances are inexorable. While tight gas, for example, is unlikely to make much of a contribution to U.S. supply in the time frame of DOE's forecast, it certainly would within GRI's horizon, especially at the prices they foresee. They do, in fact, acknowledge the conservative nature of their resource assumptions, as well as the fact that they assume drilling costs will be well above those now experienced.[43] A forthcoming updated supply projection, including assumptions about the availability of new technology, finds that "unconventional" gas can provide as much as one-third of total supply by 2010, and total availability exceeds 20 Tcf throughout the period.[44]

What drives the price that DOE forecasts? Basically, it appears to be a deeply held conviction that oil prices must, by their very nature, rise over the long-term, and that the current weakness is an aberration. In fact, the opposite is true. Non-renewable resource prices have fallen over the course of the decades, with occasional increases that are always (relatively)

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[42]Offshore production figures from **Offshore** 7/20/84. Alaskan production assumed at 1.7 mb/d.

[43]See "The Long-Term Trends in Lower-48 Gas Supply and Prices: The 1984 GRI Baseline Projection of U.S. Energy Supply and Demand, 1983-2010" Thomas J. Woods, Gas Research Institute, 2/85.

[44]"The Current Outlook for Natural Gas Supply," Daniel A. Dreyfus, Gas Research Institute, 6/85, refers to the results.

short-lived.[45]

Canada

The National Energy Board in Canada periodically produces long-term forecasts of supply and demand. Figure 18 shows their most recent baseline projection to 2005, indicating a surplus of supply throughout the period. This deliverability surplus reflects the current large backlog of gas reserves and suggests that supply availability will not be a constraint, short of massive exports to the United States. It includes assumptions that additions to reserves per meter drilled will turn sharply downward in the future,[46] and that exploratory drilling will fall off after 1990,[47] with additions to reserves falling to 20 percent of the current level by the year 2005. (See Figure 19.)

This appears to us to be conservative, since falling drilling levels should have a positive impact on return to drilling as poorer prospects are neglected. Since it still results in adequate supplies for the next twenty years, one must say that Canada's natural gas supply situation is likely to be comfortable for many years to come.

Expectations

Inasmuch as U.S. supply "deliverability" stood at roughly 19 Tcf in

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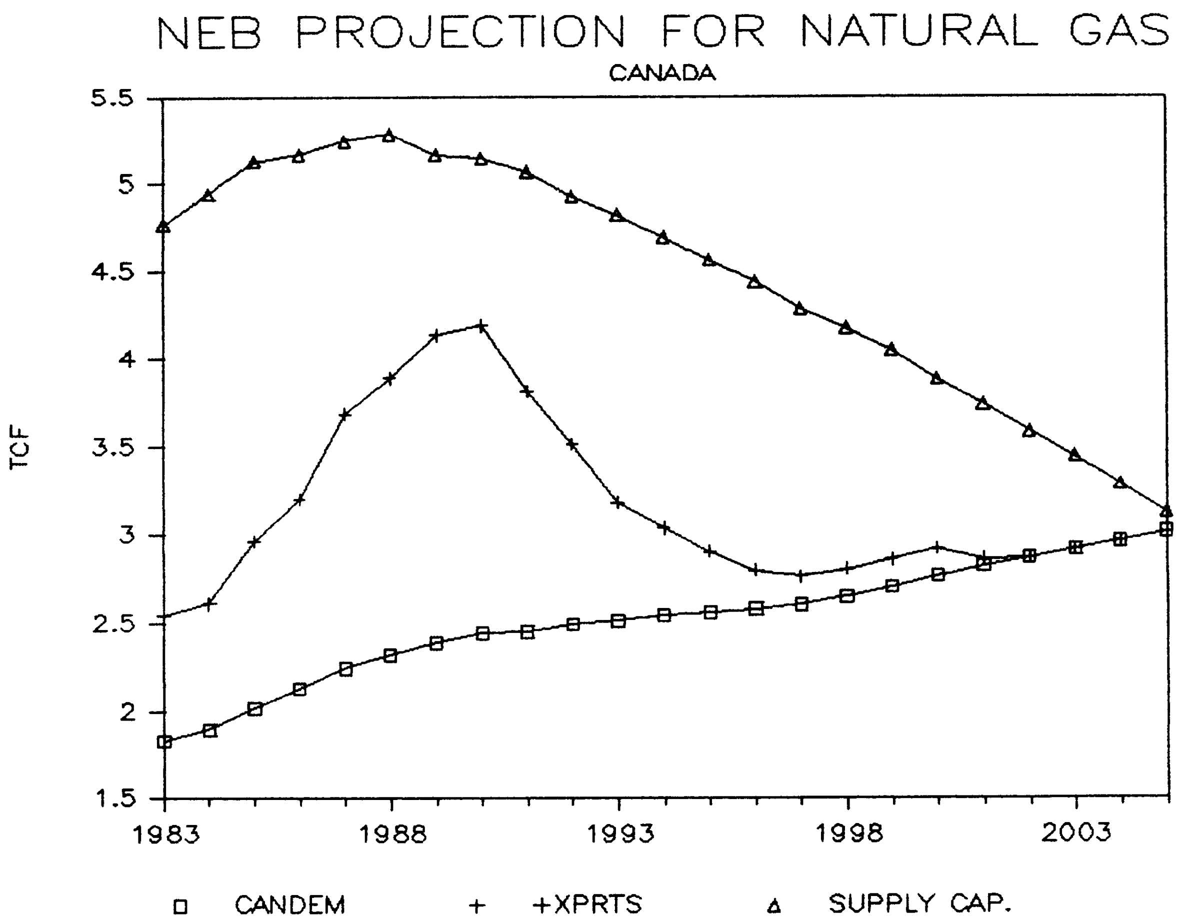
[45]See **Scarcity and Growth: The Economics of Natural Resource Availability**, Harold J. Barnett and Chandler Morse, Resources for the Future, 1963, and "Scarcity and World Oil Prices," M. A. Adelman, MIT Energy Laboratory Working Paper MIT-EL 85-008WP, 6/85.

[46]**Canadian Energy: Supply and Demand 1983-2005**, National Energy Board 9/84, p. 56.

[47]Ibid., p. A-91.

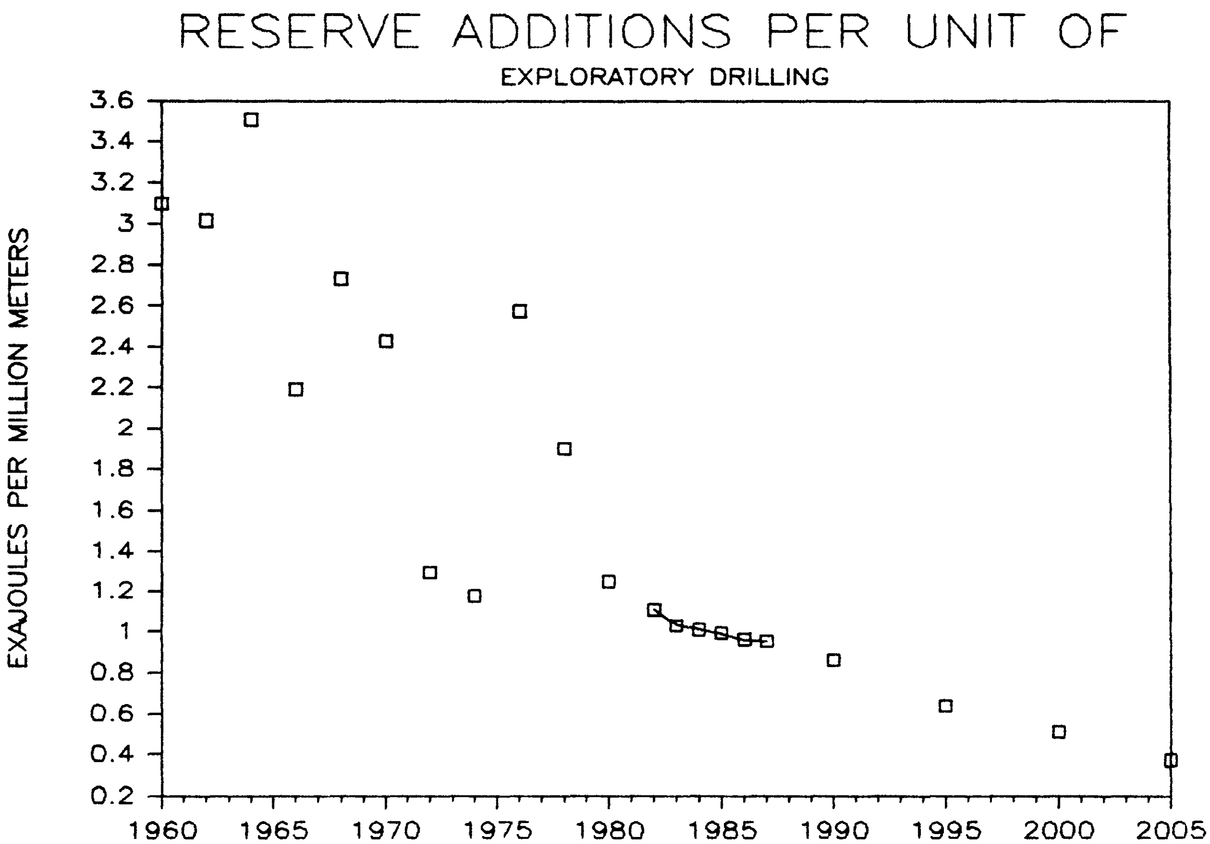
Figure 18



CANDEM = Danadian domestic demand
+ XPRTS = plus approved exports, as of 9/84
SUPPLY CAP = Deliverability

Source: <u>Canadian Energy Supply and Demand, 1983-2005</u>, National Energy Board, September 1984.

Figure 19



Source: Canadian Energy Supply and Demand, 1983-2005, National Energy Board, September 1984.

1984,[48] and drilling and reserves additions continue to hold up, if not increase, there is little near-term prospect of overall supply tightness.[49] Should prices for new contracted reserves fall drastically, i.e., below $2/Mcf, then investment in equipment, offshore leases, etc., may begin to decline, although the impact on supply will not be felt for some years. Over the longer term, of course, costs should decline, all other things being equal, and the longer it takes prices to fall, the less the impact on reserve additions.

In other words, given the current level of operating costs and the amount of money already spent on leases and equipment, plus the lag time between exploration and production, adequate supplies are likely in the United States for the next decade, almost without regard to price. Beyond that, "stability" can be expected, although prices may drift up or down somewhat, with moderation as the long-term trend (relative to current price levels).

In Canada, the only constraints on supply appear to be lack of market and government restrictions on exports. While substantially higher production levels will increase the marginal costs of reserve additions, they will also lower unit costs through greater efficiencies and shorter capital recovery time. Frontier natural gas is unlikely to play a significant role in this century, however, given the current high costs and the need to produce large quantities to achieve pipeline efficiencies. The wild card is,

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[48]Dry natural gas production was 17.2 Tcf in 1984, according to DOE, and the bubble has been put at 1.5 to 3 Tcf.

[49]The latest estimate by the American Gas Association is for excess gas productive to decline to 2.4 Tcf/yr. in 1986, from 2.9 Tcf/yr. in 1985 and 3.2 Tcf/yr. in 1984. See **Oil and Gas Journal**, "Newsletter" 9/2/85, p. 3.

of course, the level of rents that various levels of government take.

Regional Analysis

So far, average marginal costs for the United States (excluding Alaska) and Western Canada have been discussed, but the variance that occurs between natural gas deposits can be large. Certainly, in a competitive market, marginal costs should be equal for all areas, after transportation cost differentials are considered; however, given different levels of rents taken by the various governments involved, and the different nature of the costs involved, there is some utility in providing more specific analysis.

The different nature of costs becomes important during a weak market, as now exists. If there is a risk of prices falling, then developers should seek fields with a higher proportion of operating costs to total costs, because they can be shut-in to provide savings, should prices drop below the level of variable costs. Similarly, if there is a probability that prices will drop enough to make two prospects unprofitable, then the one with the longer development time will involve greater risks.

Thus, it can be anticipated that future efforts will be biased towards onshore fields in the conventional provinces, i.e., Western Canada, and the U.S. Gulf Coast, rather than in the Canadian Arctic and E. Coast offshore, deep gas, etc. Since development of frontier areas also entails new transportation facilities, a further disadvantage exists. Of course, sunk costs in the form of Arctic drill ships, leases signed, and so forth, will lower the marginal cost of operations in some areas for the short- to medium- term future, but a trend to conventional gas projects appears to be underway.[50]

This section will thus consider the differing prospects for gas in such areas as offshore East Coast of Canada, the Canadian Arctic, Foothills gas in Western Canada, deep waters offshore the U.S. Gulf Coast, and such unconventional sources as tight gas and deep gas.

Development Cost in the Venture Field

As a measure of costs in the future, we apply the methods described earlier to large current projects, where some fragmentary data have been released. Of course, there is an immense advantage in having costs for a specific field rather than the averages we have been using.

Data for the Venture field offshore Nova Scotia were originally derived from the environmental impact statement, but have apparently been much revised. From the **Venture Gas Project: Application to the National Energy Board for an Export Licence**, Petro-Canada, August 1985, we derive the following basic data:

Reserves:	2.36 Tcf
Peak output:	320,000 mcfd = .1168 Tcfy (as well as

[50]The signals, unfortunately, are not very clear. Gulf Canada is selling off its Arctic equipment, for example, but says it now plans to concentrate on development of the prospects it has discovered, rather than further exploration. Bids for leases on the offshore U.S. Gulf Coast have fallen drastically, but the quality of the leases cannot be assumed to be comparable with previous auctions, and some companies appear to be working off backlogs of undrilled acreage for now. See **Oil and Gas Journal**, 8/5/85 "North American Arctic Report" and 8/19/85, "Lease sale off Texas draws weak response," pp. 56-57. The fact that most exploration costs in the Canadian Arctic were borne by the government in the past makes it difficult to ascertain the economic viability of Arctic exploration. A new policy is currently being formulated which may end most or all of these subsidies.

12,826 barrels daily of liquids, 4.7 million barrels per year)

Hence: $\underline{a}$ = .0495, low by North Sea standards, but there is no reason to distrust it.[51]

Capital expenditures: US$1837.5 million (C$2450)

Operating expenditures: US$75 million/year

Hence annual operating expenditures are 4.1 percent of capital expenditures. (Compare rule of thumb 3 percent in capital intensive projects.)

Discount rate: $\underline{i}$ assumed 12 percent to make some allowance for unusual risk in an untried area.

Hence: Development capital cost = $0.78/Mcf in ground, $2.65 as sold.[52]

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[51]Our calculation assumes initial output at the maximum, then a continuous decline at the depletion rate. In fact, the typical production profile is a very rapid buildup, a brief plateau, then a relatively rapid decline which later slows down greatly. James L. Paddock and M.A. Adaelman show that in the North Sea fields, there is a very high correlation between actual present values, and the ones calculated by using the discount rate and the ratio of peak output to reserves as a proxy for the decline rate. See Adelman & J. L. Paddock, "An Aggregate Model of Petroleum Production Capacity and Supply Forecasting," MIT-EL Working Paper 79-005WP, Revised July 1980. Hence the error seems tolerable. Of course an actual profile of expenditures and outputs would be a great improvement.

[52]Excluding exploration expenditures. See the earlier discussion of development costs for the difference between and determination of in-ground and above-ground costs. Using only "proved" reserves which are implied at 1.85 Tcf by the Mobil appliciation, Volume II, p. 2-4, the in-ground costs become $0.99 and the above-ground costs increase to $2.87.

In reckoning operating cost per unit, we must first allow for the production of gas liquids, whose costs were included above. If we credit them with a value of $20 per barrel (a low value, to make allowance for the remote location and costs of storage and transport), this would amount to revenues of $94 million per year, leaving a credit of $19 million annually. However, the liquids revenues will decline, while the operating costs will not, at least not to any important extent. Perhaps it would be best to let the two offset each other, and put total development cost at $2.65 per Mcf.

The questions we wish to pose are:

(a) Can the gas be sold at $2.65 **plus** transport cost to Boston, reckoned roughly at 80 to 90 cents?[53]

Consider that before the recent decline in short-term prices, they were stable at about $2.70 in Louisiana. The distance is 1550 miles. If it were necessary to build a new large pipeline to bring in large amounts of additional gas, the cost of transmission would be about 8.5 cents per hundred miles. The total cost delivered would be $4.02, or somewhat higher than the delivered cost from Venture. However, if the new gas only displaced other gas from dwindling reservoirs, and were shipped through an existing pipeline, the delivered cost would be much lower, and so would the Boston city-gate

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[53]Based on the export license filing by Petro-Canada, the cost **to the U.S. border** would be about 60 cents per Mcf (1985 US$). This is substantially higher than the normal pipeline costs, although the terrain to the U.S. border is said to be particularly difficult. New pipeline construction to the Massachusetts market should add another 20 to 30 cents per Mcf to delivery charges. See "Venture Gas Project: Application to the National Energy Board for an Export Licence, Volume 1, Application and Agreement," Petro-Canada Inc., August 1985, p. 2-2. A recent report quoted industry analysts as putting delivered costs in the $6-8/Mcf range, but this might include taxes. It is certainly higher than our estimate. See "Mobil and TransCanada are Prepared to Fight Over Right to Build Pipeline," **Wall Street Journal**, 10/14/85, p. 6.

price.[54]

Apparently the Venture gas can be sold, but only as a large incremental supply. It barely competes with existing supplies or small increments from existing U.S. pipelines. However, some buyers have apparently been persuaded to sign an incautious contract, set with reference to heating oil or some other marker, for a large fixed supply, such that the project should go forward.

(b) A return of 12 percent may be enough to induce development. It seems too little to induce exploration. Hence the Venture field would be the last developed in the area for some time to come.

(c) There is no allowance for tax take by either the provincial or the federal governments.[55]

The Venture field therefore looks marginal at best. If the gas price is expected to rise, then it should definitely be postponed. If the gas price is taken as constant, postponement appears even more preferable. However, if the development can be combined with the recent discoveries of Glenelg (Shell) and of other fields in the area, perhaps costs can be substantially reduced, and the project made viable. If the project is seen as opening the gates to development of the (potentially) large natural gas resources off Eastern Canada, then it might be deemed worthy of subsidy by the provincial and federal governments. Whether a market for this amount can be found in

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[54] Operating costs are roughly 1 cent per Mcf per 100 miles, or 15 cents from Louisiana to New England. This would bring the delivered price below \$3/Mcf, although regulators would presumably insist that some amount of capital charge be applied.

[55] In fact, both may waive any necessity for rents, seeing the project as a loss leader, which will encourage future field development and provide export income and industrial development for Eastern Canada. See "Government Aid Urged for Work off Nova Scotia," **Oil and Gas Journal**, 9/23/85, p. 50.

New England is discussed in the section on demand.

Canadian Arctic

Through 1983, roughly C$7 billion[56] had been spent in the Canadian Arctic, although to date a minor amount of oil and no gas has been produced. With the exception of Panarctic's first small shipment of oil in late 1985, there are no specific plans for production, and no development plans now pending. However, large quantities of oil and gas have been discovered, in pools ranging up to 400 million barrels of oil and 2.5 Tcf of natural gas. Total discovered resources were estimated at 750 million barrels of oil at the end of 1983 and 23.5 Tcf of natural gas.[57]

In fact, the Amauligak field is hoped to be the one large oil field necessary to justify pipeline development so as to lower transportation costs for later developments. Esso Resources has been considering an extension of the Norman Wells pipeline north, in order to transport small amounts of oil. Development costs of Amauligak have been put at about $30,000 per daily barrel of capacity,[58] and for the smaller Tarsuit field, perhaps three to five times that much.[59]

Natural gas is another matter. No estimates of individual field

[56]Canadian Petroleum Association, **Statistical Handbook**, current dollars. Most of the money was spent in the last ten years.

[57]Geological Survey of Canada, 1983. Given the slow nature of drilling in the Arctic, and the reluctance to list many fields in such a high cost area as reserves, this number undoubtedly understates the drilling results. It does not include, for instance, the Amauligak field of Gulf, which is still being delineated and is believed to hold 400 million barrels, according to **Oil & Gas Journal**, 7/29/85, p. 62.

[58]**Oil and Gas Journal**, 8/5/85, p. 63.

[59]Geological Survey of Canada, 1983, p. 24.

development costs are yet available, but one would assume them to be high. The geographical dispersion of the natural gas costs reduces the potential for efficiencies in parallel development. The proposal by Polar Gas to build a pipeline suggests transportation costs to the U.S. border of $2/Mcf,[60] such that even modest production costs would leave fields uneconomic at current price levels. Given the amount of gas available in Alberta, and considering that the minimum amount of a combination of new sales and old gas shut-in would be 300 Bcf/yr, the prospects for this project seem poor. Certainly, Alberta producers can be expected to oppose it strenuously.

Foothills Gas

The Foothills Basin, part of the Deformed Belt along the Rocky Mountains in Alberta, has aroused interest due to the presence of large natural gas reservoirs. At present, established reserves are estimated at 8 Tcf, and the average expectations of potential reserves are put at 15 Tcf.[61] However, only when natural gas prices rose to dizzying heights did interest in the zone grow, since the gas is very deep, the rock is hard and tends to have low porosity, often requiring fracturing, and the gas tends to be very sour. Some fields, in fact, could be considered sulfur deposits contaminated by methane. Table 16 lists some of the fields in the Foothills basin,

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[60] Capital costs are put at C$3.3 billion for the pipeline to Edson, Alberta, about 400 miles short of the U.S. border. Initial deliveries are projected at 800 mcf/d, although capacity is likely to be expandable beyond this with some additional investment. However, an NEB study suggested that costs would approach $4/Mcf. See "A Strategic Gas Model to Study the Optimal Allocation of Canadian Natural Gas," National Energy Board Strategic Gas Study, Appendix B, p. 37.

[61] See Geological Survey of Canada, 1983, and E. N. Tiratsoo, **Oilfields of the World**, third edition, Scientific Press, Ltd. (Beaconsfield, England: 1984), p. 320.

TABLE 16
FOOTHILLS NATURAL GAS FIELD CHARACTERISTICS

Field	Initial Raw Gas (bcf)	Initial Market-able Gas	Percent Recoverable	Surface Loss (%)	H2S Content (mol/mol)
Jumping Pound West	2219	1491	0.672	20	0.064
Lookout Butte	530	219	0.413	25	na
Panther River	648	122	0.189	[1]	0.623
Pincher Creek	1585	328	0.207	31	na
Quirk Creek	570	364	0.638	25	0.160
Whiskey	154	111	0.718	0.15	0.400
ALBERTA	162194	97573	0.602		

Source: Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids, and Sulphur at 31 December, 1981 and 31 December 1984. ERCB.

[1] The largest deposits at Panther River are listed at 100% surface loss. Surface loss represents processing for liquids, sulfur, etc.

indicating the high sulfur content and the large amount of processing required to produce this gas.

All of these factors offset the higher productivity, making the gas prohibitively expensive. Since field development typically takes twice as long as most other Western Canadian plays, the disincentive to invest in this area is quite high. The fact that the gas is sour, corrosive, and even hazardous, raises the prospect of resistance to field development by local residents.

U.S. Gulf Coast: Green Canyon

Obviously, gas supply will continue from the U.S. Gulf Coast offshore area for many decades, but there has been increasing excitement about the potential for very large finds in deeper waters, such as the Green Canyon area. Capital costs for deep water, at depths of more than 600 feet, have fallen sharply with new technologies, to the extent that development of a field today might cost one-fourth of what it did ten years ago.[62] Even so, it appears that with optimistic price assumptions new oil discoveries are marginally economic, and gas fields not at all. Thus, we do not expect large supplies of natural gas from this sector for at least the next decade.

Unconventional Gas

At present, consideration of the role of unconventional gas, which could be said to include gas from tight formations, deep gas, methane from hydrates, and geopressurized gas, will be limited to noting the potential for

[62] See "Frontier Petroleum Development Economics: New Exploration Plays--Development at What Cost?" Thomas A. Petrie and Suzanne W. Wright, First Boston Research, 8/84.

reserves. Estimates of the size of these reserves in the United States and Canada indicate that they are abundant far beyond conventional natural gas, in the realm of hundreds of trillion cubic feet.[63] Canadian Hunter, for example, claims to have identified several hundred trillion cubic feet of tight natural gas in the Deep Basin along the Alberta-British Columbia border.[64] However, the costs of production from very the different sources of unconventional gas are so high that currently they are not considered a part of either country's economically relevant resources.

What they demonstrate is that the current supply curve is nearly horizontal in the range of $5 to $10 per Mcf. Over the longer term, into the next century, these sources may provide the replacement for depleted "conventional" gas, much of which was itself defined as "unconventional" only a few decades ago.

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[63]For one survey of estimates, see **A Survey of United States and Total World Production, Proved Reserves, and Remaining Recoverable Resources of Fossil Fuels and Uranium**, by Joseph D. Parent, Institute of Gas Technology, December 1983. The exploration editor of the **Oil & Gas Journal** recently put U.S. tight gas resources at 500 Tcf, and total unconventional, excluding gas from coal gasification, at 1900 Tcf. See **OGJ** 5/13/85, p. 133. In Canada, one recent article used an estimate of 187.5 Tcf of tight gas in Alberta. See "The Future of Liquid Fuels in Alberta," D. Quon, S. Wong, S. Singh, and R.D. McDonald, **Journal of Candian Petroleum Technology**, November-December 1984.

[64]"Future of Gas lies in Conventional Sources," **Oil and Gas Journal**, 5/13/85, p. 133.

Appendix A

EXPLANATION OF ABOVE-GROUND FACTOR

We are able to calculate how much it costs to book an additional reserve unit. But the producer needs to hold the asset thus created until he sells it off. The real supply prices must allow for the ratio of above-ground to in-ground values.

Let: Q = initial output, in Mcf/year
a = decline rate, percent/year
i = interest rate, percent/year
p = current and expected price

Then: reserves $R = \int_0^T Q\, e^{-at}\, dt$
$= (Q\,(1-e^{-at}))/a$

decline rate $a = Q\,(1-e^{-at})/R$

Undiscounted value of reserves = PR

Discounted vanue of reserves $= PR\int_0^T e^{-(a+i)t}\, dt$
$= PR\,(1-e^{-(a+i)t}))/(a+i)$

At realistic values of T, i, and a, the expressions in parentheses rapidly approach zero

Then the ratio of discounted above-ground reserves to undiscounted below-ground reserves is approximately:

$(a+i)/a = (a/a) + (i/a) = 1 + (i/a)$

Thus an Mcf above ground is worth $(1+(i/a))$ times an Mcf below ground. More precisely, if an Mcf above ground cannot be expected to sell for $(1+(i/a))$ times its cost to create under ground, then it is not worth creating

Intuitively, it is obvious that the higher the interest rate, and the longer it takes to get the gas out (reciprocal of a), the more expensive it is to hold the gas.

The shorter the holding time, the better. But the faster the depletion, the greater the investment cost. Hence the optimum rate is a tradeoff between higher investment and quicker return.

The depletion rate is only an approximation to the true decline rate, and is subject to biases both up and down. [For a fuller discussion, see Adelman, Houghton, Kaufman, and Zimmerman, Energy Resources in an Uncertain Future (Ballinger, Cambridge, Massachusetts, 1983), Appendix B.]

Appendix B

NORTH AMERICAN LNG PROJECTS

I. INTRODUCTION

Only a few years ago, quite a number of liquefied natural gas (LNG) projects were being considered for North America. However, nearly all of them were import projects into the United States, on the assumption that U.S. city-gate natural gas prices would support the high transportation costs associated with LNG. Even small producers like Trinidad and Tobago had such plans, which multiplied when the Iranian Oil Crisis drove price expectations upward. Since then, the weak U.S. market with its attendant falling wellhead prices has led to all of the existing import projects being cancelled save one small one to New England (45 Bcf/yr).[1] At present, two projects are still extant to export natural gas from North American to the Asian region, especially Japan. While these projects will be dealt with more carefully in the study on the Asia/Pacific market, they impinge on the North American market, and a brief analysis will therefore be provided here.

Specifically, estimates of the project costs will be analyzed to provide some idea of the resulting wellhead value, and the economic desirability for respective producers.[2] The two projects currently under consideration are the Western Canada export project to Japan, and the proposed Trans-Alaska Gas System, which is seeking customers in East Asia.

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[1] Even this is now jeopardized by the recent declaration of bankruptcy by the importer.

[2] Representative landed prices in Japan will be used for now; the next phase of study will examine actual LNG prices, current and future.

II. Alaskan Natural Gas

A few years ago, when the continental U.S. appeared to be running out of natural gas supplies, the Alaskan Natural Gas Transportation System (ANGTS) proposal sought to develop pipeline capacity to bring 2.4 Bcf/d (876 Bcf/yr.) of natural gas from Prudhoe Bay to the continental United States, partly via Canada, at a total cost estimated at the time of $10-15 billion.[3] This equates to $16-24 billion in 1984 $, using the U.S. implicit price deflator for the gross national product,[4] but in fact, others have estimated that costs escalated much more rapidly than this, with estimates of $40 billion not uncommon.[5] At the latter estimate, the capital cost per Mcf would be over $10, delivered, not including any operating or production costs.[6] Since Canadian natural gas exports are currently selling for about $3/Mcf at the border, the infeasibility of this project can be readily seen.

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[3] Decision and Report to Congress on the Alaska Natural Gas Transportation System, Executive Office of the President, Energy Policy and Planning (U.S. Government Printing Office: Washington, D.C., September 1977), p. 100.

[4] From the **Economic Report of the President**, Council of Economic Advisers (U.S. Government Printing Office: Washington, D. C., 2/85), p. 236. If the Oil and Gas Journal Morgan Oil Pipeline Cost Index is used, the result is similar, although individual intervening years vary quite a bit.

[5] For example, see "Second Trans-Alaska Gas Pipeline Proposed," **Oil & Gas Journal**, 9/26/83, p. 43. The most recent piece of work to provide estimates is **Oil and Gas Technologies for the Arctic and Deepwater**, Office of Technology Assessment, May 1985. However, the estimate they give is from **Export of Alaskan Oil and Gas**, Stephen Eule and S. Fred Singer (New York: Universe Books, 1984). They put total costs at $40 to 50 billion, with $25 to 30 billion for the Alaskan segment alone, and they estimate results in delivered prices of $7.50/Mcf (OTA, p. 128).

[6] Capital costs are estimated using a 20% internal rate of return. Testimony given by Vernon Jones, President and CEO of the Northwest Energy Co. before the Senate Subcommittee on Energy Regulation, 11/16/83, indicated that if the costs were levelized, then the delivered tariff could be held to about $5.00/Mcf, "only" about twice current Canadian prices.

As a result, the possibility of Alaskan natural gas entering the domestic U.S. market appears remote. While the estimate of $10/Mcf is probably seriously overestimated, for reasons that will be discussed below, even a reduction in costs of 50% will not render this project feasible. Even though substantial cost reductions are available, the stipulation that financing be provided by outside institutions means that the possibility of massive cost overruns, such as occurred in the Trans-Alaskan Pipeline System for crude oil (TAPS), and the weakness of the U.S. natural gas market, probably make this too risky an undertaking for most financial institutions.

However, an Alaskan LNG export project implies a long-term contract, decreasing some risks substantially, and a large portion of the costs will be shifted from a trans-Canadian pipeline to an LNG plant, with more certainty about costs.

Project Costs

There are a number of factors that could lower the costs for the TAGS project compared to ANGTS. The ANGTS project consisted of 4,787 miles of pipeline, 2,028 of which was in the United States, and 2,759 above the Canadian border. (Using these proportions and the $40 billion project costs would suggest that the capital cost of natural gas delivered to the Canadian border would be greater than $6/Mcf; of course, the costs would be borne in the northernmost section out of proportion to the mileage relationship, given the remoteness and harshness of the terrain.) The TAGS system includes only 820 miles of pipeline, which, using cost factors from the ANGTS proposal, would still cost over $10 billion, and deliver gas at a cost of about

$3/Mcf. This is an improvement, but leaves the gas in southern Alaska, far from any large markets.

Before addressing the costs of the LNG portion of the project, the possibility of cost reductions for the pipeline must be considered. A major endeavor on the part of those promoting the TAGS system is to reduce costs to the extent necessary to make the project feasible, and in fact, pipeline costs not only make up the largest part of delivered (cif Japan) natural gas prices, but appear to be the most uncertain.

A recent study for the TAGS project suggested that the pipeline could be built for "only" $8.2 billion.[7] As Table B-1 shows, the cost are quite similar to those encountered for the TAPS project. However, a number of factors suggest that these costs can be reduced.

In the first place, it is commonly believed that due to the perceived urgency in the construction of the TAPS, costs were not tightly controlled. Many estimates put these excess costs at 30 to 40% of the total.[8] The effect of reducing costs from the original TAGS estimate by this amount is shown in Table 1, as Assumptions Ia and Ib. Beyond this, though, it has been pointed out that basing the costs of a natural gas pipeline on those for a crude oil pipeline in Arctic regions is fallacious.[9] Specifically, the heavy Prudhoe Bay crude oil (27 degrees API) is hot, requiring the pipeline to be well insulated or raised above the permafrost. Not only is this not a

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[7]"Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas," Report by the Governor's Economic Committee on North Slope Natural Gas (Anchorage, Alaska, January 1983), hereafter referred to as Brown & Root. There has been a later report, which is said to revise costs downward substantially, but we do not as yet have it.

[8]No specific published reference at this point.

[9]Again, we are indebted to Mead Treadwell.

Table B-1
Alaskan Pipeline Costs

Cost for TAGS using estimated cost factors from:	Total Capital Costs (Billion $)	Capital Costs per Mcf ($/Mcf)
TAPS	8.9	2.44
ANGTS	10.7	2.93
B&R: TAGS	8.2	2.25
Assumption I:		
a: -30%	5.7	1.57
b: -40%	4.9	1.35
Assumption II:		
a: -10%(I.a.)	5.2	1.42
b: -10%(I.b.)	4.4	1.21
c: -20%(I.a.)	4.6	1.26
d: -20%(I.b.)	3.9	1.08
Assumption III:	2.0	0.55

Assumptions:
I: Correction for TAPS cost overrun, 30-40%.
II: Lower pipeline costs, 10-20% reduction.
III: Polar Gas estimated costs.
(See text.)

Pipeline capacity is based on amount of delivered LNG not throughput. Length is 820 miles, "capacity" is 2 bcf/d. Costs per diameter inch/mile from Mead Treadwell.

problem for natural gas, but it is expected that the gas will, instead, be chilled. Chilling involves added expense, but the pipe requires insulation only in areas of discontinuous permafrost. At this point, we do not have estimates of the magnitude of cost savings likely to result from this, but they are clearly significant.

Beyond this, one must assume certain savings over the TAPS project due to better knowledge of working in Arctic conditions, and improvements in technology, etc., resulting in our assumption of overall savings of 10 to 20% from the Assumption I capital costs, shown in Assumption II.

Given the paucity of data on pipeline construction in northern regions, the estimate made by Polar Gas for a pipeline from the Mackenzie Delta to Edson, Alberta, is of great interest. At C$3.3 billion for a 1333-mile, 36-inch pipeline, this would translate into a $2 billion cost for the TAGS system, assuming all factors were equal (which of course they are not). Still, this does show the potential for costs lower than those projected for Alaskan pipelines, although the extent to which terrain and/or regulatory differences are responsible, instead of better technology, is not clear at this point.[10] We have used this estimate for our most optimistic scenario, as a cost floor for the pipeline. Of course, if this were a valid estimate, then the ANGTS pipelines could provide natural gas to the U.S.- Canadian border for less than $2/Mcf.[11] Needless to say, we consider this unrealistic, although more up-to-date estimates of costs for an ANGTS-type

[10] Mead Treadwell, again, suggests that new techniques would be employed by Polar Gas to lower costs, but no quantification of possible savings is available. The possibility that Polar Gas is underestimating costs to gain support for the project cannot be entirely dismissed.

[11] Using (2759 miles in Alaska and Canada) divided by (820 miles in the TAGS project) times $2 billion, for total capital costs of $6.7 billion.

project should be interesting.

The resulting capital costs for the pipeline range from $1.08 to $1.42/Mcf for the "conservative optimistic" and down to $0.55/Mcf using the Polar Gas proposal for a guideline. Operating costs have not been included, but instead, the method used in the analysis of the Venture project will be used. Since more than 100,000 b/d of liquids will be delivered at relatively low costs, we shall, for the moment, assume the profits cover total pipeline operating costs.[12]

As for liquefaction costs, estimates abound and vary significantly, for several reasons. In the first place, many of the plants are built in hostile environments, which can raise costs drastically. Secondly, liquefaction plants have been subject to the same inflation that large-scale capital projects fell prey to in the 1970s. And, too, the amount of experience with this type of plant is still small. As Table B-2 shows, estimated costs also vary according to the size of the plant, there being economies of scale. For our pessimistic estimate, we have used the $1.55/Mcf Brown & Root Phase I estimate, by far the highest in our sample. For the "Moderately Optimistic" scenario, we have employed the $1.10/Mcf costs from the Brown & Root Phase II estimate, while the "Optimistic" scenario reflects the more optimistic

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[12]Expected production of liquids is 113 tb/d, at a capital cost for "conditioning facilities" of $1.4 billion (both numbers for the full TAGS project, i.e., 14.5 million tons of LNG, or 2 Bcf/d). The capital cost equates to less than $10/barrel of liquids, exploration costs are zero, and operating costs should be some fraction of development costs. Assuming a price of $20/barrel, profits should be more than $900 thousand/day, or $330 million per year, roughly equal to 6% of the least optimistic capital cost assumption (II.a. in Table 1).

As it happens, Arco is now putting in a liquids separator to strip the LPG from the gas produced at Prudhoe Bay before it is reinjected. Thus, the gas liquids would not be available to offset costs for the TAGS project, but neither will the expense of building the processing plant. This will be dealt with in more detail in the next phase of the project.

Table B-2
LNG Capital Costs Estimates

Liquefaction Plant

Source:	Capacity (mcf/d)	Capital Cost (Million 1982$)	Capital Cost (per bcf/d) (Million 1982$)	Capital Cost (1982$/Mcf)
IEA	870	1160	1333	0.73
	2600	2899	1115	0.61
Vrancken	870	1300	1494	0.82
	870	1500	1724	0.94
Mueller	500	863	1726	0.95
	500	1055	2110	1.16
DiNapoli	1000	1217	1217	0.67
Brown & Root:				
Phase I:	658	1863	2833	1.55
Phase II:	562	1132	2016	1.10
Phase III:	767	1633	2129	1.17

Note: Annual capital charges are 20% of total capital cost.

Sources:
IEA = Natural Gas: Prospects to 2000, International Energy Agency, (Paris, 1982).
Brown & Root = "Trans Alaska Gas System: Economics of an Alternative for North Slope Natural Gas" (Anchorage, 1983).
DiNapoli = "Economics of LNG Projects," Oil and Gas Journal, 2/20/84.
Vrancken = "The Exportation of Natural Gas", in The Economics of Natural Gas Development (Venice, 1982).
Mueller = "LNG: A Prince or a Pauper" presented in Calgary 9/83.

estimates of the IEA and DiNapoli, and also the falling prices of large-scale capital projects that have been experienced in the last several years. In other words, we assume that a hard bargain can be driven with liquefaction constructors.[13] We definitely expect little or no inflation in real construction costs for this type of project in the near- or medium- term future.

For our final liquefaction costs estimates, operating costs are assumed to vary from 3% to 5% of annual capital costs, from $0.20/Mcf for the "Pessimistic" scenario, to $0.05/Mcf for the "Optimistic" one.

Perhaps because of their location in developed areas, regasification plants show a greater convergence in cost estimates around $0.40/Mcf.[14] For our pessimistic scenario, we use $0.40/Mcf, dropping it 5 cents per Mcf for each increasingly optimistic scenario.

Shipping costs for LNG seem to vary least of all, perhaps due to the fungibility of tankers, as the only part of LNG projects which can be transferred or resold. Our pessimistic estimate reflects a cost of $0.25/Mcf/1000 miles, based on a number of observations.[15] For Alaska to

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[13]With the Japanese yen being very weak against the dollar, a much lower dollar bid can be made by Japanese companies, for example. This is, of course, a temporary phenomenon, but recent bidding on capital projects of this scale have seen fierce competition and cutthroat prices. See, for example, ""How Japan Sealed Deal to Build a Big Bridge Spanning the Bosporus," **Wall Street Journal**, 5/29/85, p. 18, and "Big Builders Learn to Think Small," **New York Times**, 7/28/85, p. F1.

[14]Bijan Mossavar-Rahmani, "OPEC Natural Gas Projects Face a Bleak Outlook," **Petroleum Intelligence Weekly**, 3/19/84, p. 7, estimates a cost of $0.44/Mcf, while the International Energy Agency, **Natural Gas: Prospects to 2000**, 1982, p. 127, puts the cost at $0.40/Mcf. Robert N. DiNapoli, in "Economics of LNG Projects," **Oil & Gas Journal**, 2/20/84, p. 47, gives a range of costs depending on project size, from $0.50/Mcf for a 600 mcf/d project to $0.30/Mcf for a 2 Bcf/d one.

[15]These will be discussed more fully in the next phase of the project.

Japan, the distance is 3775 miles,[16] so the total transportation cost would be $0.95/Mcf. The availability of used LNG tankers might result in lower costs, as reflected in the "Moderately Optimistic" scenario, and larger tankers would reduce the costs to $0.20/1000 miles, or $0.75 as shown in the "Optimistic" scenario.[17]

Before closing our discussion of costs, the question of inflation should be addressed. As mentioned above, capital intensive projects on these scales saw very substantial real cost inflation during the 1970s. However, using U.S. pipeline costs as a surrogate for all capital projects, it appears that this inflation is a temporary phenomenon, not a long-term structural problem. (See Figure B-1.) In fact, long-term, albeit slow, deflation seems more the norm. Thus, we feel comfortable in assuming no real cost inflation in these project costs estimates.

Return: Wellhead Value in Alaska

As can be seen in Table B-3 and Figure B-2, the profitability of this project depends very much on both the degree of cost savings and the market price for the delivered LNG. The cost of delivery, from wellhead to Japan (regasified), varies from $4.6/Mcf to $2.55/Mcf, with a "moderate" assumption being about $3.55.[18] Given a landed price of about $5/Mcf, the existence of some rents is clear, although field production costs will reduce them somewhat. Any reduction in expected price brings down the wellhead value by

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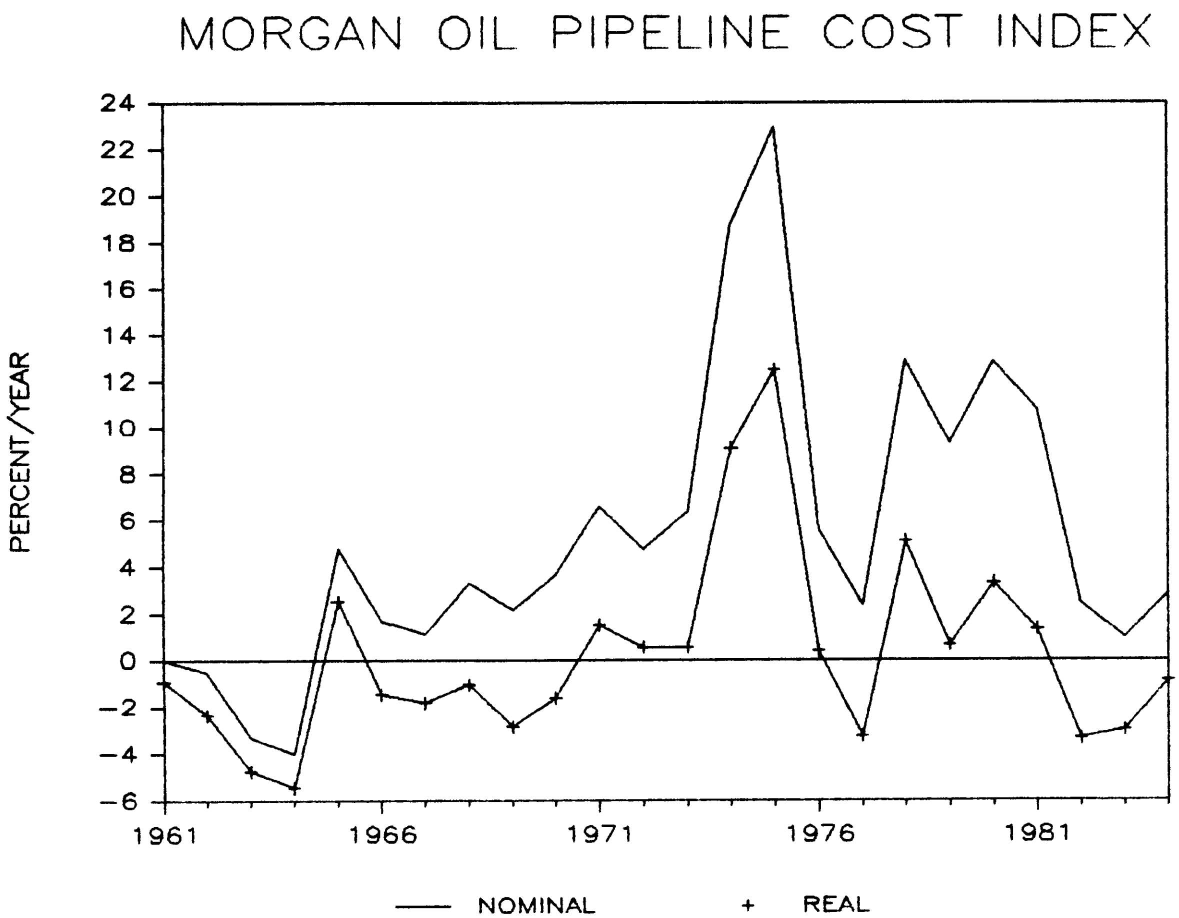
[16] See **Petroleum Press Service**, 1/70, p. 10.

[17] DiNapoli, op. cit.

[18] Although we include regasification costs when analyzing delivered prices to Japan, the reported prices, which are currently about $4.75, do not include them.

Figure B-1



Source: Oil & Gas Journal.

Table B-3
Value of natural gas from Prudhoe Bay
Delivered to Japan/E. Asia
($/Mcf)

A. Most Pessimistic Cost Scenario

Price of Gas (cif)	5	4	3
Regasification	0.4	0.4	0.4
Transportation	0.95	0.95	0.95
fob price	3.65	2.65	1.65
Liquefaction	1.75	1.75	1.75
"Citygate value"	1.9	0.9	-0.1
Pipeline	1.5	1.5	1.5
Wellhead value	0.4	-0.6	-1.6

B. "Moderately Optimistic" Cost Scenario

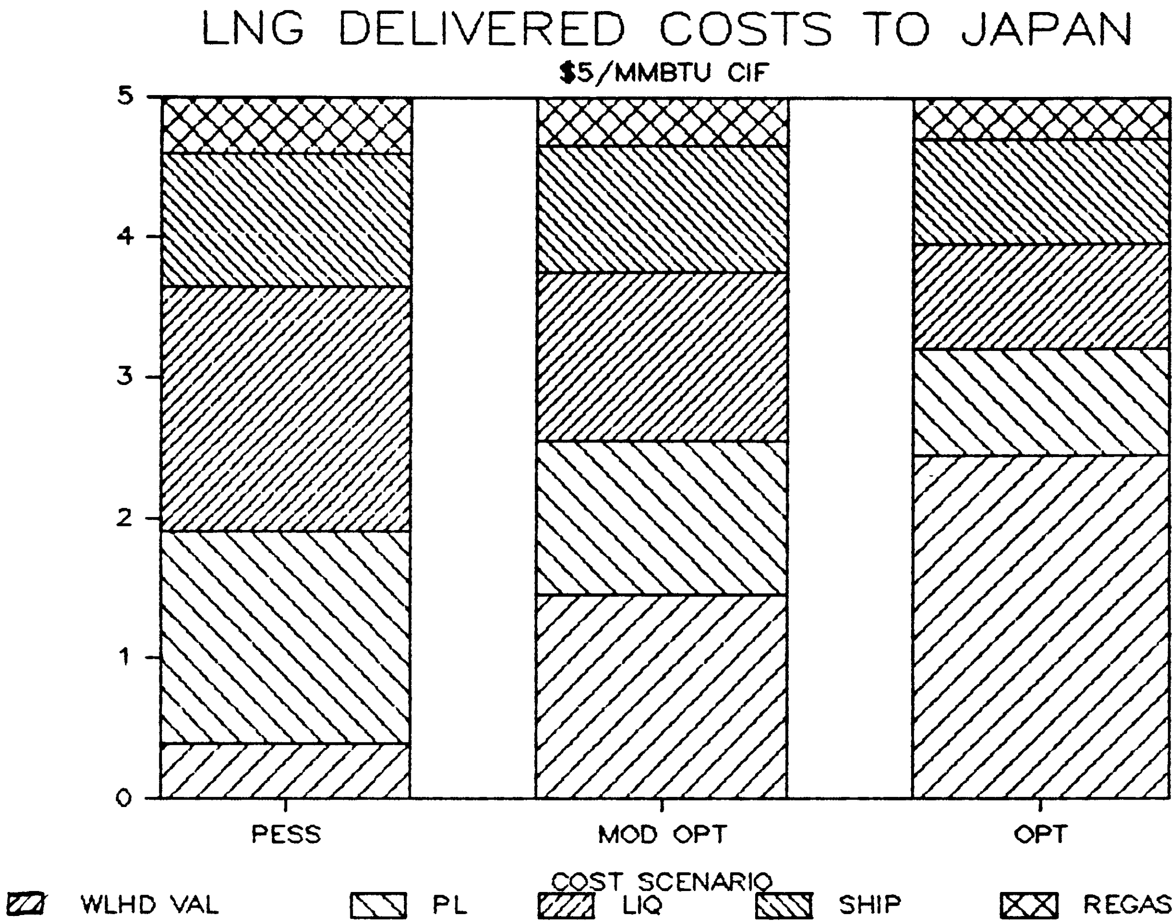
Price of Gas (cif)	5	4	3
Regasification	0.35	0.35	0.35
Transportation	0.9	0.9	0.9
fob price	3.75	2.75	1.75
Liquefaction	1.2	1.2	1.2
"Citygate value"	2.55	1.55	0.55
Pipeline	1.1	1.1	1.1
Wellhead value	1.45	0.45	-0.55

C. "Optimistic" Cost Scenario

Price of Gas (cif)	5	4	3
Regasification	0.3	0.3	0.3
Transportation	0.75	0.75	0.75
fob price	3.95	2.95	1.95
Liquefaction	0.75	0.75	0.75
"Citygate value"	3.2	2.2	1.2
Pipeline	0.75	0.75	0.75
Wellhead value	2.45	1.45	0.45

Source: see text.

FIGURE B-2



Cost components:

Wellhead value
Pipeline
Liquefaction
Ship transportation
Regasification

an equivalent amount. If the "Pessimistic" cost estimates prove to be the valid ones, then the project has no real economic viability. For the "Moderately Optimistic" cost scenario, an LNG export project has potential, but is risky, given weak oil prices. The "Optimistic" scenario's economics appear attractive, even given the risk of some price erosion.

We consider \$5/MMBtu an optimistic price, and \$3/MMBtu a pessimistic one. At present, all Japanese contracts equate LNG prices with landed crude prices, on a Btu basis, but there is no assurance that this will continue in new contracts. Indeed, should oil prices decline to \$20/barrel, in 1984\$, a very real possibility by the time this project begins deliveries, then LNG prices would fall below \$4/MMBtu.

III. WESTERN CANADA LNG EXPORT PROJECT

The LNG project, led by a consortium made up of Mobil, PetroCanada, Westcoast Transmission, Nissho Iwai, and Suncor, has sought approval to export \$40 Mcf/d (145 Bcf/yr) to Japan from British Columbia.[19] For a variety of reasons, including the weak market for LNG in the second half of this decade in Japan, regulatory delays in Canada, and financial difficulties, especially on the part of Dome Petroleum, the original operator, the project's ultimate fate remains uncertain. However, given the available estimates of capital costs for the project, both its viability and its desirability, which are not precisely the same, can be discussed.

The original costs for the project were put at \$2 billion for the

[19] The loss of one customer, Osaka Gas, has reduced the amount under contract to 124 Bcf/yr.; the project configuration at the lower levels of delivery has not been made public yet. Alternatively, another customer might be sought.

liquefaction plant, $1 billion for tankers, and $1 billion for a 550-mile pipeline from the gas fields. However, due to "more finite engineering and lower inflation",[20] these estimates were reduced to $1.7 billion for the liquefaction plant, $700 million for the pipeline, and $100 million for the tankers, which would be leased rather than purchased.

Even using these costs, however, the delivered costs to Japan surpass $4/Mcf,[21] similar to the "Pessimistic" scenario for the TAGS project in Alaska! Of course, some economies of scale have been lost due to the small size of the project, but unless every source has mistakenly identified Canadian dollars as U.S. dollars, these estimates are extremely high. Even converting them from Canadian dollars leaves, for example, the liquefaction plant costing $1.275 billion, more than DiNapoli's estimate for a plant 2.5 times as large! (See Table B-2.)

However, since the original proposal called for a delivered price on the order of US$6.68/Mcf (by virtue of being based both on crude oil prices and Canadian export prices to the United States, which were then $4.94/Mcf[22]) and other reports put the price to Albertan producers at C$2.25/Mcf (US$1.70),[23] it appears that the cost estimates given above are valid.

That being the case, and given a market (i.e. the United States) for

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[20]Dome President John Beddome, cited in **Oil & Gas Journal**, 11/21/83, p. 35. Other costs estimates can be found in OGJ, 2/14/83, p. 67 and 12/19/83, p. 66, as well as throughout the trade press.

[21]The liquefaction capital costs would be $2.35, pipeline costs $1, and shipping costs presumably over $.5. Given a reasonable estimate for operating costs, the total would come to about $4.25, ignoring regasification and production, as well as the costs of delivery to the pipeline, which should be minor.

[22]**Oil & Gas Journal**, 2/14/83, p. 67.

[23]**International Gas Report**, 4/13/85, pp. 1-2.

natural gas at roughly $2.70/Mcf, minus transportation costs to the border, which are largely sunk, it seems unlikely that this LNG project will go forward. While there are some benefits to diversifying customers, especially given the monopsony position of the U.S., these benefits are unlikely to outweigh the very large economic costs.

On the other hand, it would not surprise us to see a reconfigured project with much lower costs suggested.[24] If the per unit costs for the LNG segment could approach those shown in the Alaskan section above, say $1.5, shipping on the order of $0.75, and pipeline costs more in line with continental U.S. pipelines, (i.e., 8.5 cents/Mcf/100 miles, or US$0.50 instead of $0.70), then the price to Albertan producers could be US$2.25/Mcf, given a landed, but not regasified, price of $5/Mcf in Japan. If prices drop to $4/Mcf, then the benefit is reduced drastically, and it would seem better to wait for the U.S. market.[25] Still, half of the gas is to be provided by producers in British Columbia, who lack the access to the U.S. market that Alberta producers have, and accordingly, a lower price should be more acceptable to them.

These two projects highlight the dilemma of natural gas producers everywhere who are faced with a choice between waiting for a low-return, low-cost nearby market and exporting at high cost to a distant market, where the price may not be particularly favorable. In future work, the effect of different cost factors and market availability on other producers will be seen.

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[24] A new estimate of capital costs is expected in the fall of 1985.

[25] A $4 price in Japan, implying a $1.25 return to Alberta, would have an equivalent present value to waiting for 7 years for a $2.50 sale to the United States, assuming a 10% discount rate.

THE DEMAND SIDE OF NORTH AMERICAN TRADE IN NATURAL GAS

by

Arthur W. Wright

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1. INTRODUCTION

Analyzing the demand side of North American trade in natural gas involves conventional theorizing and testing, but also considerable intuition and some crude guesswork. Because of a regulation-induced shortage, the U.S. interstate gas market did not even operate on the long-run demand curve until the early 1980s. For some years before then, Canadian and Mexican suppliers of gas enjoyed inflated spillover demands from across the border. Since 1982, however, the U.S. gas industry has found itself squarely on the demand curve, and not feeling all that good about it. In the too-familiar North American pattern, some Canadian firms have come down with pneumonia. For its part, Mexico has opted out of the trade for the time being.

The recent changes have forced North American gas producers, pipelines, and local distribution utilities to reassess the demand for gas on its fundamentals. Unfortunately, we still have much to learn about the fundamentals of gas demand. The "structures" underlying our existing models generally apply to the pre-1973 period. Gas markets have changed considerably since then, and more than once. Lacking anchors to the past, we face an uncertain future. To single out just the major uncertainties: What will two national and many provincial or state governments do? What course will oil prices follow? And is the decline of basic manufacturing in North America cyclical or secular?

What follows consists, appropriately, of some conventional theorizing and testing, spiced with plenty of intuition and more than an optimal amount of crude guesswork. One consolation may be that it is often worthwhile to know at least the extent of one's ignorance.

2. THE NATURE OF DEMAND FOR NATURAL GAS

2.1 Economic Demand Functions

Throughout, the "demand" for gas will refer to a function relating different quantities demanded by purchasers to different prices charged by sellers. Typically, one or more "shift parameters" will (if varied) increase or decrease the entire relation between prices and quantities. Perhaps the central shift parameter in gas demand functions is the price of the competing oil product (such as residual fuel oil). Other shift parameters are gross domestic product or household income, user equipment stocks and prices, technologies, and people's preferences (or "tastes").

By postulating that individuals or firms behave rationally, we can deduce that demand curves "slope downward": At high prices, lesser amounts of a good will be demanded than at lower prices, holding constant the various shift parameters. As a rule, quantity demanded will respond more to a given price change in the long run than in the short run. The notion is that at least some of the shift parameters tend to be fixed in the short run but variable in the long run. For example, if a price changes suddenly, the scope of purchasers' responses will be restricted in the short run. With time, however, they will gain more freedom of action as long-run changes occur--shifts in people's tastes or incomes, new end-use equipment or technologies, purchases of complementary goods, and so on.

2.2 "Final" and "Derived" Demands

It is useful to think of four distinct categories of gas demand. Only residential demand for gas is final as opposed to "intermediate" on the scale of human consumption. Commercial, industrial, and electric utility demands are, in economic argot, derived from the ultimate final demands for goods produced with the gas. Both kinds of demand still depend, short- and long-run, on the price of gas. But the other arguments in the demand functions differ by customer class, and along with them the price-responsiveness of demand.

For residential gas demand, the prices of near substitutes--mainly distillate fuel oil ("No. 2") and increasingly electric power--are important shift parameters. Household income is also an argument, as is user equipment: in the short run, the stock itself, and in the long run the prices of equipment. Government policies may affect residential demand for gas, too. In the United States, many states restricted new hook ups in the mid-1970s. Until recently, the Canadian government subsidized new hook-ups in Ontario and Quebec, as part of an "off-oil" policy.

The derived demands of commercial, industrial, and electric-utility customers do not depend on income, except indirectly through the effect of aggregate income on final-goods demands. Stocks of equipment (in the short run) and technology (in the long run) are important arguments of the derived demands. The long-run decision to install "dual-fuel" (gas and oil) capability (or, in the case of coal, to maintain spare combustion capacity) makes fuel switching a short-run possibility. For most commercial demands, relevant substitutes include distillate fuel oil or electric power. Industrial users can substitute either distillate or residual fuel oil, depending on the application; substitution in most feedstock uses is relatively limited in the short run. Electric utilities view residual fuel oil as the effective short-run substitute fuel for natural gas. Coal (base load) and distillate fuel oil (peaking) are long-run substitutes, as are also nuclear, hydro, pumped storage and other non-fossil-fuel forms of generation. Finally, public policies may also affect derived demands for gas--viz., the conflicting "off-gas" and environmental regulations found in the United States.

The different categories of gas demand may well have different marginal values in use. The differences are primarily a function of the supply prices (costs of provision) of acceptable alternatives, whether it be rival fuel/energy systems or substitute processes or final goods. Homeowners, for example, can heat with distillate fuel oil, gas, or electricity (coal is no longer widely acceptable); or they can wear extra layers of clothing, learn to enjoy ambient temperatures of 65 degrees F. (18 degrees C.), or move to the Sunbelt. Electric utilities, in contrast, find coal a quite acceptable alternative to natural gas for raising steam, even if expensive scrubbing is required for environmental reasons.

Broadly speaking, residential and commercial gas demands are less responsive to variations in price than are industrial and electric-utility demands. In the argot, the former demands are less "price-elastic" than the latter: for a given percentage change in price, the percentage changes in quantities demanded for residential and commercial use are relatively smaller than is true of industrial and electric-utility demands. Residential and commercial interests like to refer in public-policy debates to their "captive" demands; presumably, this signifies that homeowners and shopkeepers are prisoners of capital outlays that represent a large fraction of their total costs of gas use. Some of the very biggest commercial gas customers are able to switch off gas to residual fuel oil, and hence have quite price-elastic demands. And some industrial customers (e.g., petrochemical producers and certain process heat users) have much less elastic demands than the "penny-switchers"--electric utilities and large-boiler users who swing from gas to residual fuel oil and back in response to relative-price movements of as little as a cent per million Btu (MMBtu).

These seeming arcana of natural gas economics are important to understanding how gas markets operate under various conditions. Differences in marginal use-value and price elasticity across market segments imply the existence of distinct ranges in the total demand curve in a given market. Figure 1 depicts in stylized form the national U.S. market for natural gas at end-use as it might look circa 1985. The highest demand prices and steepest slopes occur in the region labelled "R+C" (for residential and commercial), where distillate fuel oil and electricity are the reigning substitutes. Next comes the region of industrial demand (labelled "I"), followed by that for electric utilities' demands (labelled "EU"). Note that the range of the R+C region of the demand curve below where the I region begins is not relevant: No seller will sell gas for R+C use if selling for I-use will fetch a better price. And similarly for the range of the I region below where the EU region begins.[1]

Exactly where on the demand curve a given market will "clear"--where, in other words, the supply to that market intersects the demand--is of considerable importance to gas marketing decisions. Few gas markets in North America afford the opportunity to price-discriminate within the major demand categories, absent regulations restricting competitive entry. Thus, sellers could not for long get away with charging two customers different prices (net of any differences in costs of serving them). A price-taking seller of gas will realize greater revenues, other factors being constant, if the market clears in the residential-commercial range than in the industrial-electric-utility range of the demand curve. Not long ago, natural gas was a "premium" fuel in North

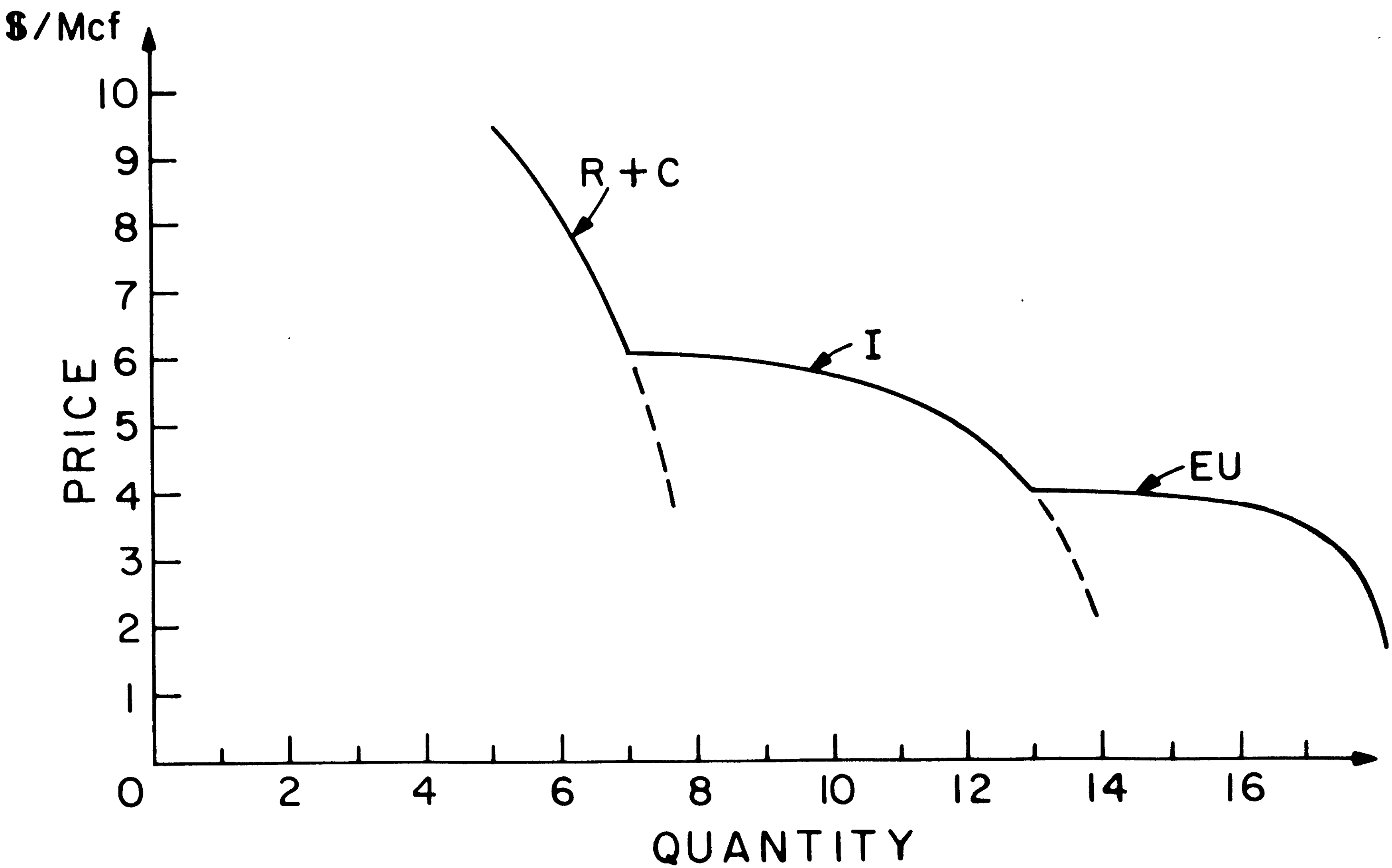


Figure 1

America--that is, incremental units of gas delivered to most markets outside the U.S. Gulf Coast fetched residential-commercial prices. Today, it is more of a "blue-collar" fuel, because many gas markets are clearing against residual fuel oil and even (in the long run) perhaps against coal.

2.3 What Do We Know Empirically About Gas Demand?

We know a fair amount about residential and commercial demands for natural gas, in the sense that a lot of studies have been conducted. (Douglas Bohi succinctly summarizes these studies in his Analyzing Demand Behavior: A Study of Energy Elasticities, Baltimore, 1979, pp. 92-105.) Broadly speaking, the studies find:

small short-run price elasticities (-.03 to -.50);

rather larger long-run price elasticities (-.37 to -2.42, with some clustering around -1.0); and

thin evidence of weak income elasticities.

(However, Cohn, Hirst and Jackson, in a 1977 study at Oak Ridge National Laboratory, found income elasticities of between 1.59 and 2.18 for 1955, 1965, 1970, and 1974; note that they also obtained by far the largest estimates of long-run price elasticity, -1.54 to -2.42, for the same years.)

There is some evidence from these studies that commercial demand appears more price-sensitive than residential. If true, the results for residential-and-commercial demands combined may overstate price effects for just residential demand alone. A 1974 Rand Corporation study by Kent Anderson did find the reverse, although some inconsistencies among the results weaken the reliability of his conclusion. (See Bohi, pp. 104-5.) Using pooled time-series data (1959-74) for Ontario and British Columbia, Berndt and Watkins found a long-run price elasticity of -.69 (quite close to an earlier result for the

United States with a similar approach) and a long-run income elasticity of .13 (well below the U.S. counterpart result, although the Canadian results were more robust).

Further, in considering the implications of the existing studies for the future, one should keep in mind that they all used gas and other energy prices from 1974 and earlier years--prices that were much lower (in nominal or real terms) than present levels. At today's higher real prices, residential and commercial gas demands could well be more price-elastic than the estimates obtained with lower prices. In the absence of more recent findings on income elasticities, it is difficult to say what we might expect over the next ten to fifteen years.

Studies of industrial and electric-utility demand are both sparser and less informative than those available for residential and commercial. (See Bohi, pp. 105-13.) The fundamental reason seems to be that the binding U.S. interstate price ceilings of the 1970s limited us to observations of supply decisions. Moreover, industrial and utility customers had much lower priorities for gas during the era of curtailments. (Even in normal times, these customers buy a lot of gas on an "interruptible" basis, which poses some econometric challenges.) And studies using data from the pre-shortage period suffer from the objections that (1) firms' investment decisions on fuel-using equipment were probably affected by the impending shortages and curtailments; and (2) the structure of fuel-choice and investment decisions is doubtless quite different today--after two oil shocks--from what it was in the 1950s and 1960s.

The recent emergence of several large data bases based on detailed surveys holds out hope that new studies of gas demand can be done for the 1980s. (Two examples are a commercial-buildings data base developed by the U.S. Energy Information Administration, and the Major Industrial Plant Database (MIPD) compiled by Dun & Bradstreet Technical and Economic Services.) It would help if one were more confident that markets had settled down enough to permit producers, pipelines, and users to form relatively stable expectations. Even better data will, of course, leave tricky econometric questions to be solved. And in any event the new studies still lie in the future and hence are of little use to us here.

What we are left with is the firm knowledge, born of ten years' casual empiricism, that the world price of oil is probably <u>the</u> key determinant of the overall demand for natural gas. (This assumes that governments do not attempt to dictate that users of energy will see a different, controlled price of oil.) The structure of refined-product prices is not fixed over time. Moreover, the correlation between the price of any particular refined product and a substitute form of fuel is never perfect, and it will vary over time as market conditions change. But movements in oil prices will shift market demands and hence prices of substitute fuels in the same direction. It is sobering to think that a raft of conclusions about future gas demands could be wiped out--or made to look ridiculously bland--by sudden and unpredictable movements in world oil prices. This is the least satisfying kind of ignorance, because we cannot do much about it.

3. THE COMPONENTS OF NORTH AMERICAN TRADE IN NATURAL GAS

3.1 Potential Trade Flows

We tend to interpret "trade" as occurring between nations. If Canada, Mexico, and the United States were organized politically the way Europe is, there would be an enormous North American gas "trade" in this sense. Put differently, there is considerable trade in natural gas <u>within</u> these spatially large economies, especially in the United States. Our focus here, however, is on actual and potential trade <u>between</u> these three countries as currently organized.

Practically speaking, the possible trade flows are four: Mexican gas exports to the United States; U.S. exports to Mexico; Canadian exports to the United States; and U.S. exports to Canada.[2] All four flows are practicable and in fact have occurred. However, only the third--Canadian gas exports into U.S. markets--is apt to be of real significance.

3.2 <u>What Might Have Been, and What Is</u>

("If economists were kings, and pigs had wings...")

In the best of all possible worlds, or at least in the competitive world without national boundaries that an academic economist might devise, a continental North American gas market would have developed from the late 1940s on. In such a world, as Leonard Waverman (a Canadian with an M.I.T. Ph.D.) and others have pointed out, Canadian natural gas from British Columbia and Alberta would have flowed both southward into the U.S. Pacific and mountain states, and southeastward into the wheat and corn belts and the industrial midwest. The first flow would have competed with indigenous gas and with gas from the huge U.S. "mid-continent" region (Texas, Louisiana, and environs). The second Canadian flow would also have competed with mid-continent gas, displacing some of it northeastward into the Mid-Atlantic states and New England--and into eastern Canada. In this world, the portion of TransCanada PipeLine (TCPL) east of the Great Lakes probably would not have been built. Almost certainly, direct Canadian shipments to the northeastern United States would not have been a major hope for expanded export revenues.

For several reasons--including the Canadian goal of east-west economic integration and the imposition of binding price ceilings in the U.S. interstate field market--a continental North American gas market never developed fully. Apart from Canadian exports to the Pacific U.S. region, two national markets developed largely independent of one another, except for some remote, minor border crossings of convenience. In the 1970s, with the onset of the severe interstate shortage in U.S. markets adjacent to Canadian production, did the United States develop an intense interest in Canadian gas. The interest was so intense that Canadian gas imports were condoned, even encouraged, at prices that could not be paid to American producers under the price controls then in effect.

We should note here that Canadian-U.S. gas exports of the 1970s and early 1980s are a poor guide to future prospects. Both volumes and prices were greater than they would have been absent the severe shortage spawned in the U.S. interstate market by federal price ceilings. History can serve as a guide, and force of precedent often carries the day in politics. But the expectations for gas exports formed during the shortage could not be sustained in the midst of surplus, or even under just plain market-clearing. (Canadian exports to the United States are not alone here; the Alaskan segment of ANGTS and a number of LNG projects also came a cropper in 1982.) Thus, holding constant production costs, current government policies, and the total size of the U.S. and Canadian gas markets, we should not be surprised if Canadian gas exports to the United States are smaller, or at least no greater, in the 1980s than they were in the 1970s. And seeking to restore the export levels of earlier years would probably be a poor way to frame the goal of Canadian gas export policy.

Structuring Canadian-U.S. gas trade as two separate national markets imposes a tax on the system compared with what might have been. Some projects to export Canadian gas to U.S. markets begin life with one or two strikes against them. The tax must be borne, for instance, by any project to increase Canadian gas shipments to New York and New England, versus swinging more gas into the U.S. Midwest to displace gas northeastward. (This applies even to a clever project such as Shell-Canada proposed in August 1985 to ship some 18 Bcf a year for 10 years into New England through a converted crude oil pipeline.) Setting the Canadian export price floor at the Toronto city gate price, which is a manifestation of the two-markets system, clearly imposes a tax on North American gas trade. The artificial demand for high-priced gas spawned by the U.S. interstate shortage made bearing the tax easier. It will be harder to bear in the more competitive environment that seems now to be evolving.

Given what is and not what might have been, significant U.S. gas exports to Canada seem unlikely under plausible conditions over the next ten or fifteen years. The reason is the evident Canadian determination to be able to supply its own needs, regardless of location, before additional exports can be considered. Another way to put the matter is a Canadian willingness to bear a good portion of the tax referred to above in return for energy (and perhaps government) security.

The question arises of whether, given this self-imposed constraint, internal Canadian demand will constrain the flow of Canadian gas across the border. With convertible currencies and flexible exchange rates between the two countries, domestic Canadian use of gas is a legitimate competitor with gas exports southward in terms of overall national wellbeing. From a national point of view, there is no sense in increasing gas exports for their own sake, any more than the opposite attitude--Canadian resources for Canadians--makes economic sense *per se*.

If domestic demand might plausibly constitute a binding constraint on Canadian gas exports to the United States, to understand those exports we would have to undertake a detailed analysis of internal Canadian gas demand. Fortunately, we were spared from having to do so. Take as a constraint that estimated Canadian demand for gas[3] must be met before one can calculate the "exportable surplus." Take even pessimistic estimates of the proved and probable gas reserves that form the other part of the calculation. One can safely conclude that any limits on exports to the United States will be found in restrictions on transport capacity or imports, or in too high a price, but not in the size of the "exportable surplus" of gas.

We shall ignore Canadian gas exports outside North America in this phase of the study. Currently, the only interesting candidates are exports of liquefied natural gas (LNG) from British Columbia to Japan. Interest in more exotic projects, such as LNG from farther north to Europe, has sagged along with world crude oil prices. Projects to export LNG to Japan or Europe are best viewed as alternatives to North American gas trade rather than as part of it.

3.3 Mexican-U.S. Gas Trade

Potentially, this trade presents an interesting contrast with the Canadian-U.S. case, because Mexico sells gas into the producing region of the United States, whereas Canadian producers are selling into three of the five primary consuming regions. For the same production costs, the Canadians should be able to realize higher border prices than the Mexicans. There is a potential similarity, too: One plausible scenario would be for Mexico to import U.S. gas to displace domestically-used oil, which could then be exported for hard currency.

For now, however, the Mexican government has shown little interest in increasing natural gas exports northward--into a market with surplus deliverability--and even less interest in importing U.S. gas into Mexico. Thus, Mexican-U.S. gas trade appears destined to remain negligible, with only minor flows (both ways) at different points along the border.

4. ANALYTICAL FRAMEWORK: DEMANDS FOR CANADIAN GAS IN U.S. MARKETS

4.1 Some Definitions

The volume of Canadian natural gas exported to the United States in any time period will be determined on the one hand by supply factors, and on the other hand by demand factors. The supply side refers to Canadians' willingness to sell different amounts of gas at different prices--say, f.o.b. the border. The demand side refers to the willingness of U.S. buyers to purchase various quantities of Canadian gas at various delivered prices (border price plus transportation and distribution charges). Our task here is to examine the demand side of Canadian exports.

The demands for Canadian gas in the United States also depend upon two sets of factors: (1) total demands for gas in U.S. markets; and (2) the volumes of gas outside Canadians' control that will be offered for sale in those markets. Set number (2) does not say that sellers of Canadian gas are limited to "leftover" or "residual" demands.[4] Rather, it is a reflection of the unpleasant fact that an offer to buy X amount of gas at a given price cannot be met with more than the X amount--unless at least one party lowers the price. Thus, so long as would-be exporters of Canadian gas cannot prevent others' gas supplies from being offered for sale in U.S. markets, their opportunities to sell gas there at various prices must take those other supplies into account. The same applies, of course, to those other suppliers: If they cannot prevent Canadians from offering to sell gas in U.S. markets, they have to take Canadian supplies into account in evaluating their opportunities to sell gas there.

Formally speaking, the demand facing Canadian gas exporters in a given U.S. market is the difference at any price between total quantity demanded in the market and the quantity supplied of U.S. and other non-Canadian gas to that market. We use "supply" and "demand" here in the economic sense described earlier, of functions relating different quantities demanded to different prices, given certain parameters that (when varied) cause the entire price-quantity relationship to shift. Algebraically, we can write this Canadian demand as

$$D_c(p;\ldots) = D_{us}(p;\ldots) - S_{us}(p;\ldots),$$

where c and us stand for Canada and the United States respectively; p is the price of gas in the market in question; and ... stands for the various shift-parameters that affect gas demand or supply. Figure 2 illustrates the concept in simplified form, assuming linear demand and supply curves in a given U.S. market. Given the U.S. demand and supply curves shown, at the relatively high prices above c, the market could be (more than) fully supplied by U.S. domestic or non-Canadian imported gas. At the very low prices below b, no U.S. gas would be supplied, leaving the entire market to any Canadian suppliers willing to accept very low wellhead prices or transportation rates. Over the range of prices between b and c, there are positive quantities demanded over and above what domestic U.S. sources would be willing to supply.

Earlier, we suggested interpreting this U.S. demand for Canadian gas, not as leftovers but rather as opportunities to sell gas at various prices. We can see this interpretation in Figure 2. Consider a price such as d. At this price, a total of Q_d will be demanded in this particular market. U.S. suppliers are willing to offer S_d at this price. Assuming there is no preventing them from so offering S_d for sale, the quantity demanded for Canadian suppliers, at that price, is $Q_d - S_d$. Now, suppose that Canadian suppliers were willing to offer a larger amount of gas for sale in this market at price d. They would not

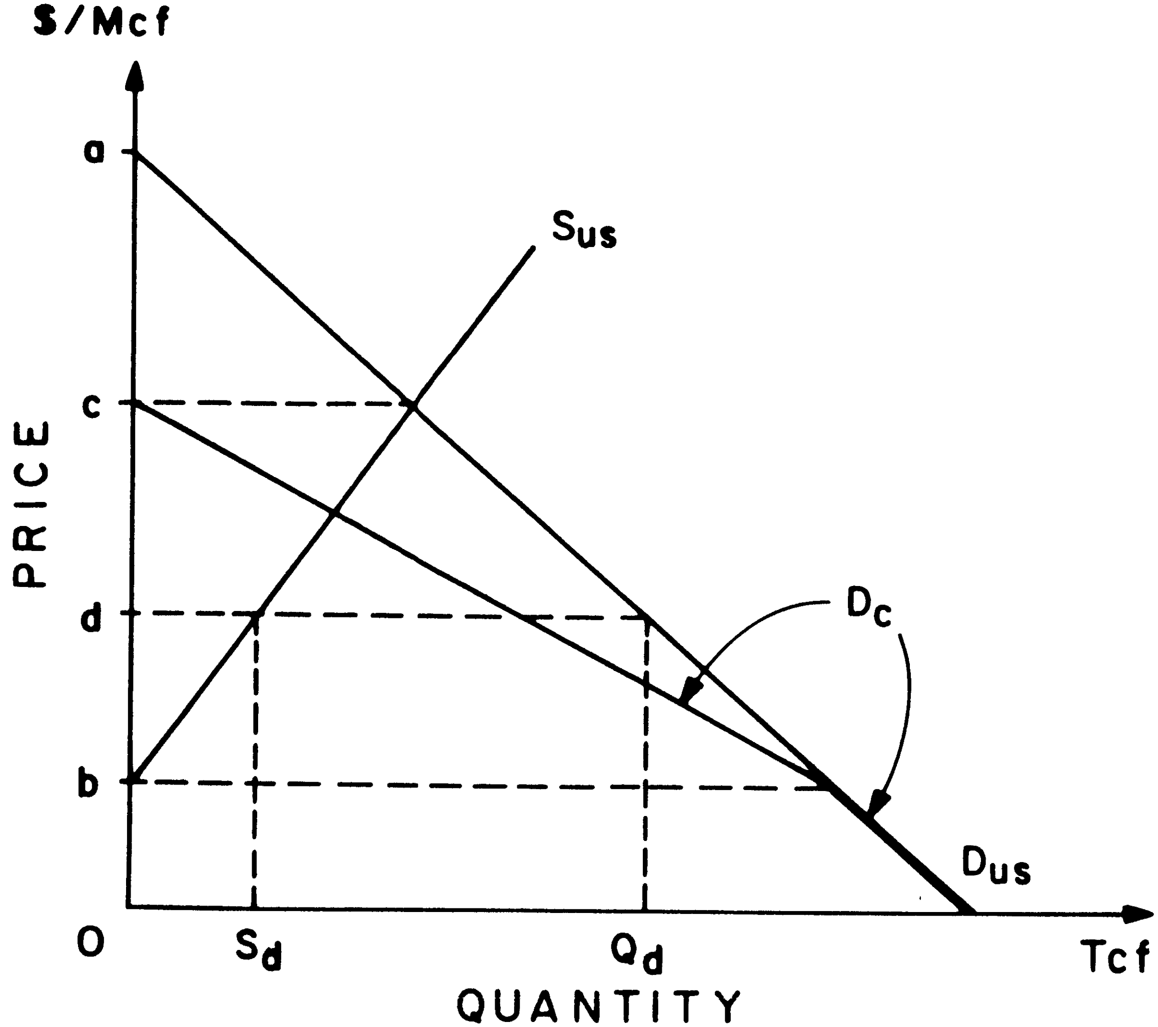


Figure 2

be prevented from doing so, either--but if they did, buyers would not take all the gas offered unless the price were lower than d. This is because the combined total quantity supplied, S_d plus what the Canadians supply, would exceed the quantity demanded in the market at price d.

The moral of the story: Canada can certainly compete on price in U.S. gas markets. But absent the ability to force the United States or other suppliers out of that market, it can sell no more at any price than the total quantity demanded at that price less what other suppliers will offer at that price. If it is any consolation, similar constraints apply to U.S. suppliers, provided there is no restriction (such as an import quota) on Canadian gas supplies flowing into the market. In effect, the above algebraic expression could just as easily have been written in terms of the net demand facing U.S. gas suppliers in the market, given Canadian supply to that market.

The form of the above expression emphasizes that opportunities to sell Canadian gas in the United States turn on two sets of factors: total U.S. gas demand, and U.S. domestic supply (plus a bit of LNG under long-term contract). Canadian export demand will increase if total U.S. demand increases, or if U.S. supply decreases, or a combination of the two. Corresponding propositions hold for rates of increase.

Similarly, the price-responsiveness of Canadian net demand depends on how price-responsive U.S. demand and supply are. Economists typically express the responsiveness of quantities demanded or supplied to price changes in the form of a price elasticity, which is defined as the percentage change in quantity divided by the percentage change in price. For example, a "more elastic" demand curve is one for which a given percentage change in price induces a greater percentage change in quantity than another demand curve. The price elasticity of Canadian net demand for gas in any U.S. market depends on the elasticities of

U.S. demand and supply as follows:

(a) Given the U.S. supply, a more elastic U.S. demand for gas at any price will mean a more elastic net demand for Canadian exports; and vice versa.

(b) Given the U.S. demand, a more elastic U.S. supply of gas at any price will mean a more elastic net demand for Canadian exports; and vice versa.

Moreover, Canadian net demand will always be more price-elastic than total U.S. demand, because it depends on both U.S. demand and supply.

4.2 Applying the Demand Analysis to the North American Gas Trade

The concept of the demand for Canadian gas exports to the United States just described depends on some strong assumptions about how North American gas markets work. The strongest is that those markets are workably competitive. Ten, even five, years ago this assumption would have been laughable. Today, it is increasingly plausible.

Currently, North American gas markets are in transition. Until the early 1980s, a highly regulated, structured system determined who would get how much gas, from whom, and at what price. This was the system that gave us, first, a damaging interstate shortage in the United States, inflated spillover demands for high-priced imports from Canada, Mexico, and Algeria, and the uniform-border price in Canada; and then an ample surplus as prices could not fall far enough, fast enough, to clear most markets. With the surplus has come a series of difficult, unevenly distributed adjustments and much consternation and confusion. Canadian gas interests are among those who have suffered most, even though they have been among the more flexible in accepting revised, more "realistic" contract terms. (One Canadian commentator on an earlier draft points out that "Canadian gas interests would have suffered even more had they not accepted pricing revisions.")

How long the transition will last is still uncertain. It would seem prudent, however, to assume that it will eventually result in North American gas markets becoming more like other commodity markets--price-competitive, flexible, and wide open to changes in market conditions. Not being prepared for competitive markets if and when they come could be costly.

Before competitive gas markets can happen, both Ottawa and Washington must come to grips with some basic issues of industrial organization. In the former case, permitting greater flexibility in choosing between spot and long-term sales seems essential. South of the border, the continued evolution towards competitive gas markets depends on greater progress in decoupling gas brokerage and trading from gas transmission by U.S. interstate pipelines. Until a broad range of actors has reliable access (through a well-organized market) to transportation capacity, U.S. gas markets will continue to be too rigid for competition to flower.

A "Notice of Proposed Rulemaking" (NOPR) by the U.S. Federal Energy Regulatory Commission (FERC), dated May 30, 1985, advanced a number of potentially significant changes in pipeline operations, especially rules governing access to capacity and alterations of capacity. Its fate is not yet clear--public comments were due on July 15, 1985, and the earliest any new rules will go into effect is November 1, 1985. The public reaction to the NOPR has made clear that the issue of price-controlled "old gas" is still an obstacle to reorganizing natural gas markets. The NOPR's proposed resolution of this issue--confining the low-priced old gas to a "Block 1" and other gas to a higher-priced "Block 2"--has drawn considerable opposition. As there is (by definition) no Canadian "old gas," how this issue is resolved may be important to Canadian gas export plans. Assurances from Washington that Canada will not be "discriminated" against on gas pricing, and on the treatment of certain pipeline costs in rates, may or may not be reassuring.[5] [As of this writing, October 1985, a new "Final Rule" essentially making pipelines common carriers and deferring block billing, pending further study, has been issued. The extent and significance of promised legal challenges to the Final Rule are not yet clear.]

The Canadian supply of gas to U.S. markets is arguably not "competitive" under existing policy. This is because it is constrained by government policies as well as the supply prices of willing, profit-maximizing producers. This does not affect the present analysis, however, which focuses on the other, demand side of the market. Given the demand for Canadian exports to U.S. markets as defined above, the decision can be made in Canada--through whatever process--on how much to offer for sale in the United States.

4.3 North American Regional Gas Markets

The prices this paper refers to should be viewed as the delivered prices of gas to any given market. Given transportation costs, Canadian shipments to that market will be positive if the (after-tax) "netback" at the wellhead is at least as great at the minimum supply price of gas in the field. Geographically, at any moment there will exist a "ridge" or watershed of competition in the United States between Canadian and U.S. gas supplies. Along the ridge, delivered prices from the two sources will tend to be approximately equal in the long run. (Actually, the ridge of competition will consist of a spatial band of some considerable width.) The location of the ridge will tend to change over time, as market conditions, or other determinants of supply and demand (such as government policies), change.

We do not presume to know precisely where this conceptual ridge of competition is now or will in the future be located. We think, however, that one can suggest the broad regions in the United States where it is likely to lie. (Most other analysts whose work we have read seem to hazard the same guess as we, so there is a consensus of ignorance here.) These regions, all rather vast in area, number three:

<u>Pacific</u>: WA, OR, CA + ID

<u>Midwest</u>: ND, SD, NE, MN, IA, WI, IL, IN, MI, OH + MT

<u>Northeast</u>: PA, NY, NJ, CT, MA, RI, VT, NH, ME.

Idaho is included in the Pacific region and Montana in the Midwest because they contain important gas import junctions for their respective regions; neither is a major factor in U.S. gas consumption. In a sense, California and the Pacific Northwest are separate (though interrelated) markets. Simplicity dictates treating them together, and California is the dominant factor in the region anyway. The California Public Utility Commission will play a key role in choosing which new gas projects go forward in coming years.

For completeness, we list below the other regions that play roles, if only indirect, in North American gas trade. They are also vast in area, and were defined largely on pragmatic grounds (although initiates in the gas industry will recognize the broad outlines that we are suggesting):

<u>Canada West</u>: BC, YU, NW, AL, SA

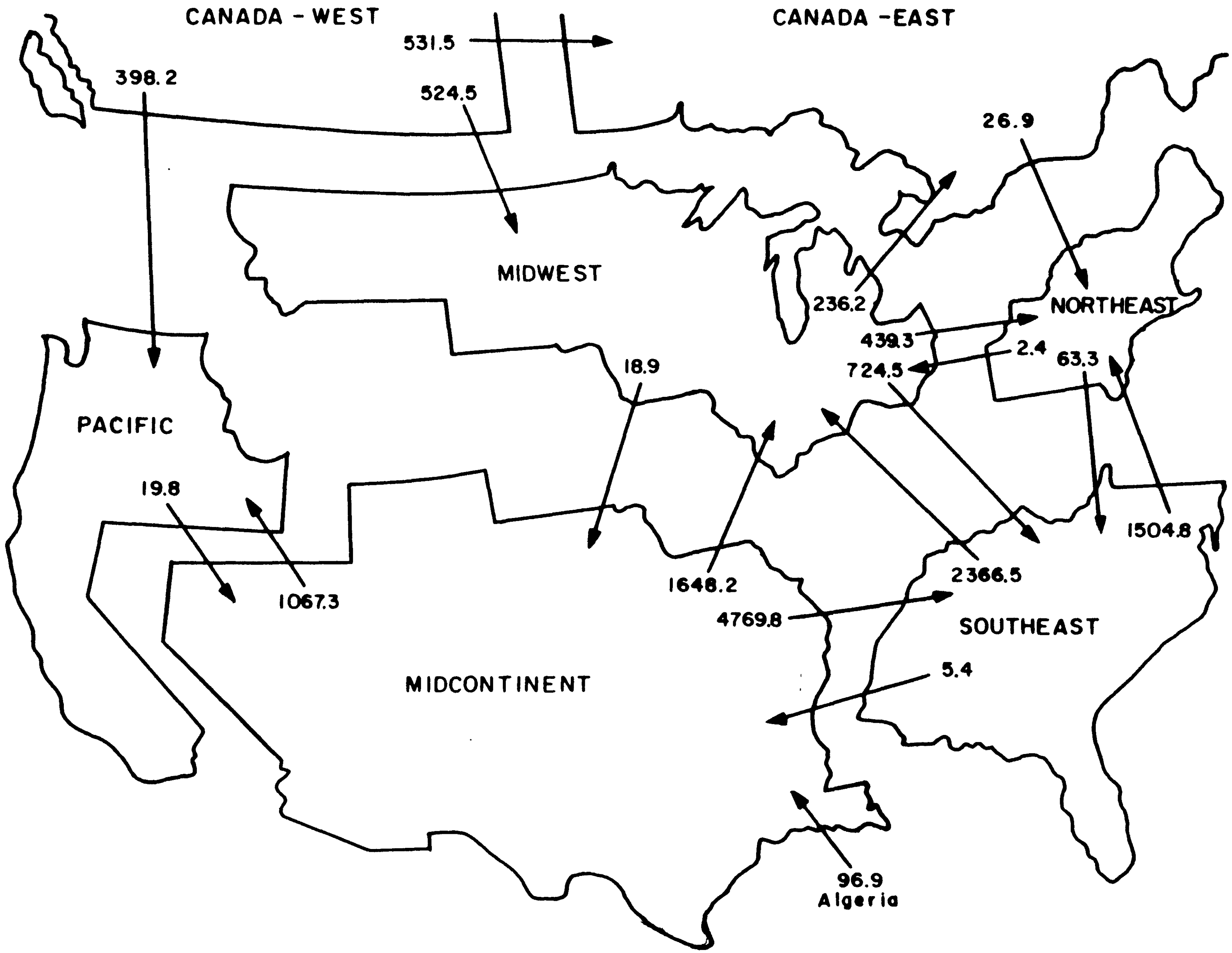
<u>Canada East</u>: MA, ON, QU + Atlantic

<u>Southeast</u>: WV, MD, DC, DE, VA, KY, NC, SC, TN, GA, MS, AL, FL

<u>Mid-Continent/Mountain</u>: AR, LA, TX, OK, KA, MO, NM, AZ, UT, NV, CO, WY

Figure 3 gives a snapshot of 1983 interregional gas flows in North America for the regions defined above.

Figure 3. REGIONAL MOVEMENT OF NATURAL GAS, 1983 (Bcf)



Source: Energy Information Administration, Natural Gas Annual 1983, Volume 1,
DOE, Washington, D.C., March 1985.

4.4 U.S. Natural Gas Supply: S_{us}

Adelman and Lynch's conference paper on the supply side of North American gas trade covers this terrain quite well and certainly more amply than we can do here. This discussion is therefore limited to a few comments that pertain to the present analysis of net demand for Canadian exports to the United States.

We exclude Alaska from effective U.S. supplies for the next ten or fifteen years. In a sense, Alaska is more naturally viewed as part of the extensive margin (or rather infra-margin) of Canadian rather than U.S. supply. This is implicit in the arrangements worked out to build the Alaskan Natural Gas Transportation System (ANGTS), with a "pre-build" portion intended to haul southern Canadian gas until more northerly gas is developed. (The financial stress that has afflicted the ANGTS in recent years is a symptom of the shifting boundary between the margin and the infra-margin.) Our view suits the analysis of continental North American gas trade better than that based on national ownership.

We now know that the "Old Mother Hubbard's Cupboard" view of gas supply that underlay U.S. wellhead price policy right up until the late 1970s was dead wrong, and plenty mischievous into the bargain. But it would be no better to adopt the opposite view that the United States will be awash in cheap gas now that the government has decided to get out of the way. The emergence of the gas "bubble" in 1983 is sometimes cited as evidence for this opposing view. In fact, the bubble had more to do with expensive gas (filtered through a rigid set of private and regulatory institutions) than with cheap gas. Many observers (e.g., economists with large oil companies owning gas reserves) expect U.S. supply prices of gas to rise steadily over the post-bubble long run, though in the short run these supply prices are falling. Adelman and Lynch consider this possible, but far from certain.

One minor consideration worth hazarding a guess on are long-term gas supplies from NGPA Section 104 ("old") gas reserves. The supply response from decontrolling old gas--which would render economic such investments as the reworking of wells and even the redesign of fields--has been the source of some controversy. It now appears that the issue is moot. A few people--those who fear that decontrol would devalue their rights to currently committed old-gas reserves--find it very important. Too many other people, in contrast, find the loss of supply from not decontrolling old gas to be of little consequence, if they pay attention to it at all. Owners of "old" gas reserves apparently are not strong enough to counter those who oppose decontrol. Thus, Section 104 gas will probably not be decontrolled.[6]

4.5 U.S. Natural Gas Demand: D_{US}

In 1981-82, the U.S. interstate gas industry met the long-run demand curve for the first time. The cause was an amalgam--supply response to rising wellhead prices under the NGPA, sagging world oil prices, and the Great Recession--that permitted gas markets to clear. In fact, prices overshot market-clearing levels through institutional rigidities that are still proving resistant to removal. As noted earlier, these events signalled the beginning of a transition from a tightly-structured, heavily-regulated system to competition.

An important question in any discussion of prospects for U.S. gas demand is, "Where will U.S. gas markets clear?" Will they clear at the margin against higher-valued distillate fuel oil, or against lower-valued residual fuel oil and even coal?

For years--as late as 1977, the year President Carter introduced his comprehensive energy policy for the United States--the notion was that natural gas is a "premium" fuel that should be husbanded for only the "highest" uses.

Those uses included residential and commercial small-space heating and (later) petrochemical production. Belief in this notion implies that natural gas markets will clear no lower than at the price of distillate fuel oil. Even for a time following passage of the NGPA in 1978, this notion was used to justify contingent price terms tied to distillate fuel oil in some gas contracts. Apart from justification, of course, such terms were offered because legal market prices still were not clearing gas markets.

One hears much less talk these days about gas being a "premium" fuel and more about how it is merely "regular," even a mere "commodity." Thus, expectations are that gas markets will clear against the "blue-collar" fuels, residual fuel oil and coal, not against distillate. These expectations have been hardened by the rapidity with which gas lost markets to residual when gas prices began to overshoot market-clearing levels in 1982.

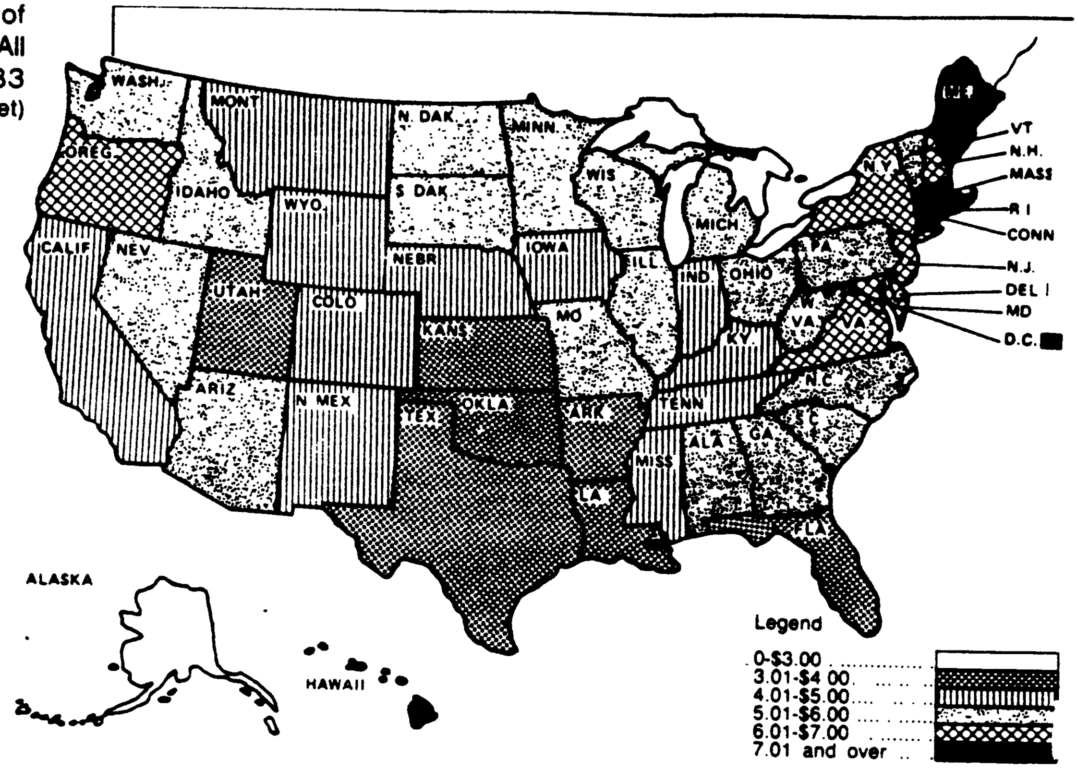
The belief that natural gas has to clear against residual or coal is no more etched in stone than was the earlier belief in gas as a premium fuel. The question is an empirical one, about which unfortunately we lack sure guidance on what the future holds. The current condition of gas clearing against residual or coal could revert to the premium-fuel situation if domestic U.S. supply prices rise quite sharply (and Canada seeks to maximize monopoly profits), or if U.S. residential and commercial gas demands grow particularly strongly. As discussed below, however, the consensus appears to be that U.S. gas markets will continue to clear in the range of residual fuel oil prices for the foreseeable future.

5. DEMAND PROSPECTS FOR CANADIAN GAS EXPORTS TO THE UNITED STATES: RECENT EVIDENCE, SOME FORECASTS, AND REGIONAL OUTLOOKS

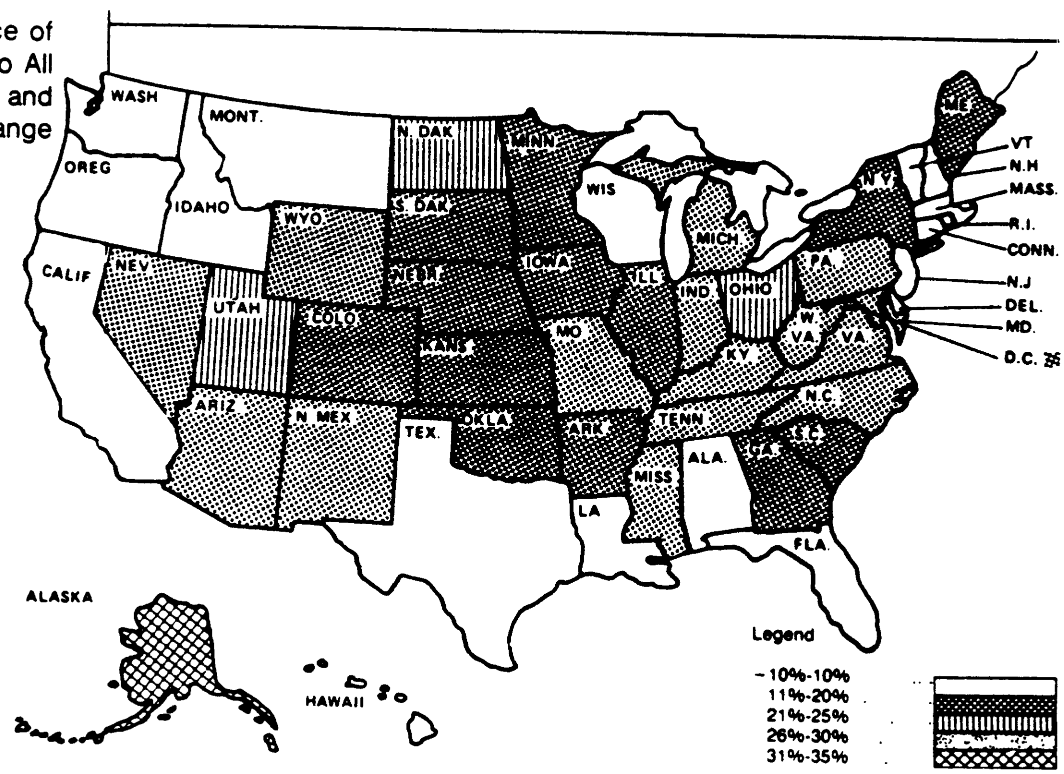
In light of the foregoing analysis, what are the prospects for Canadian exports of natural gas to the United States over the next 15 years or so? As

Figure 4

Average Price of
Natural Gas Delivered to All
Types of Consumers, 1983
(Dollars per Thousand Cubic Feet)



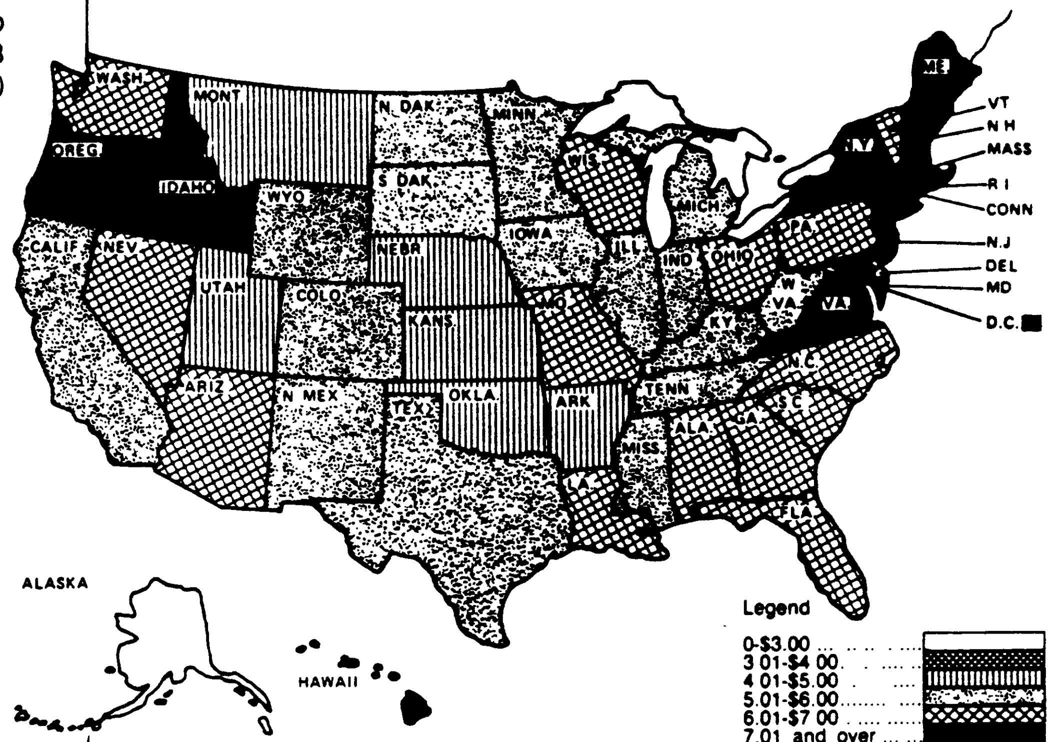
Average Price of
Natural Gas Delivered to All
Types of Consumers, 1983 and
1982 Percent Change



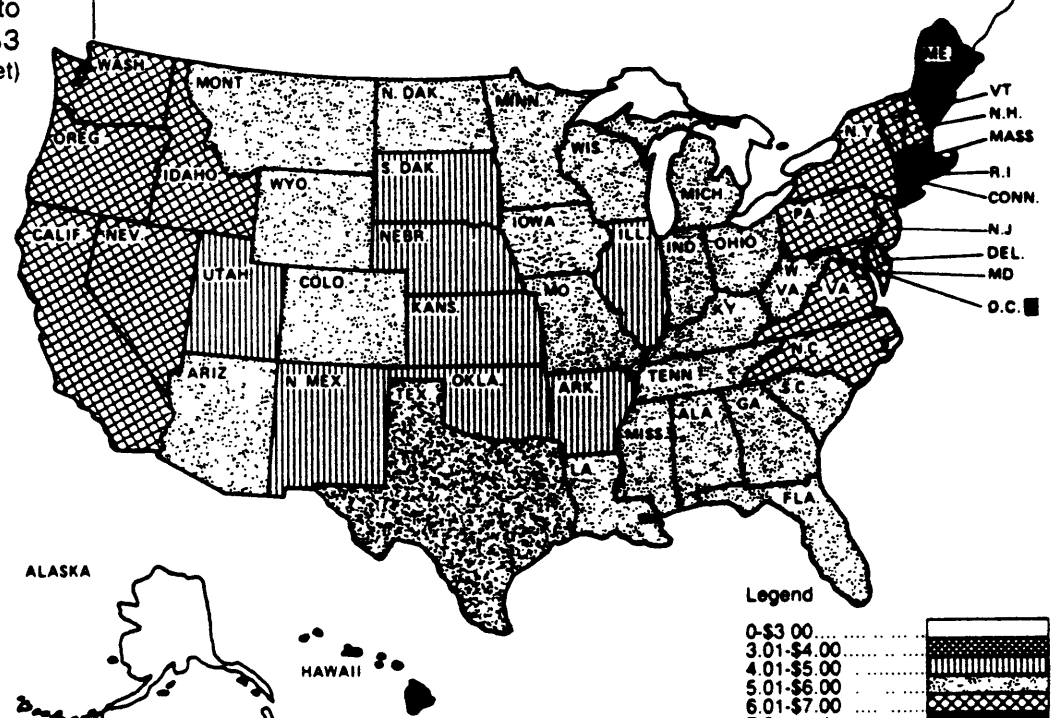
Source: Table 18.

Figure 4 (cont.)

Average Price of
Natural Gas Delivered to
Residential Consumers, 1983
(Dollars per Thousand Cubic Feet)



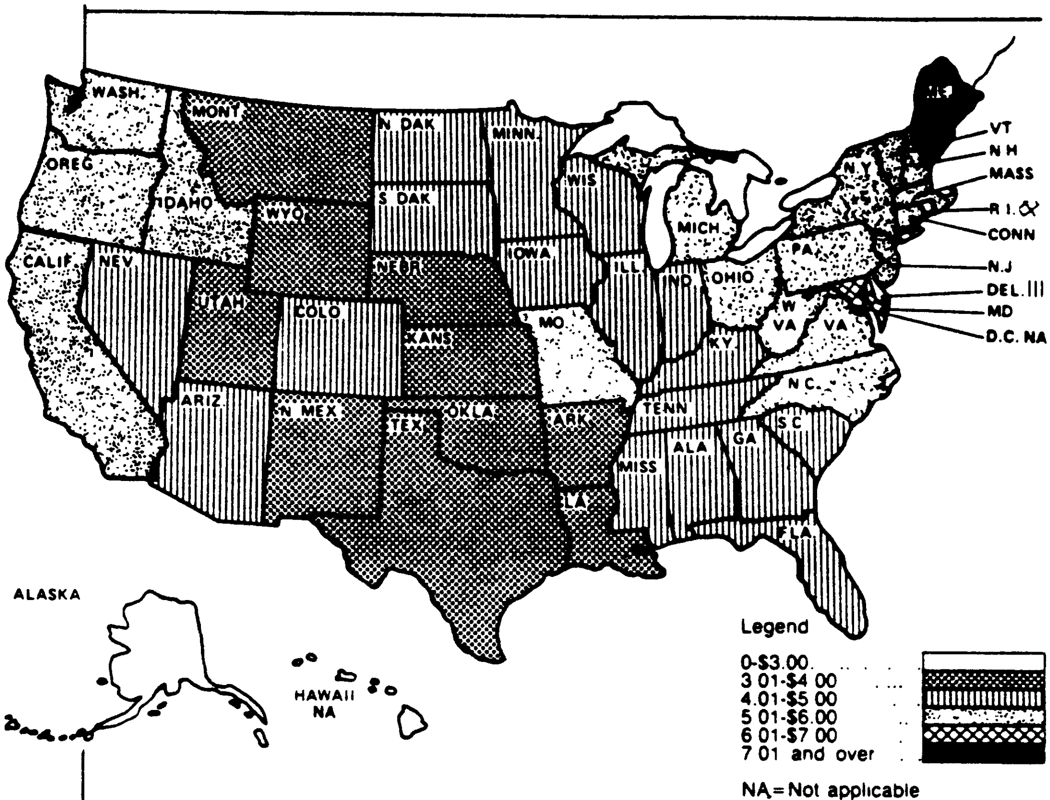
Average Price of
Natural Gas Delivered to
Commercial Consumers, 1983
(Dollars per Thousand Cubic Feet)



Natural Gas Annual 1983, Volume I
Energy Information Administration

Figure 4 (cont.)

Average Price of Natural Gas Delivered to Industrial Consumers, 1983
(Dollars per Thousand Cubic Feet)



Average Price of Natural Gas Delivered to Electric Utility Consumers, 1983
(Dollars per Thousand Cubic Feet)

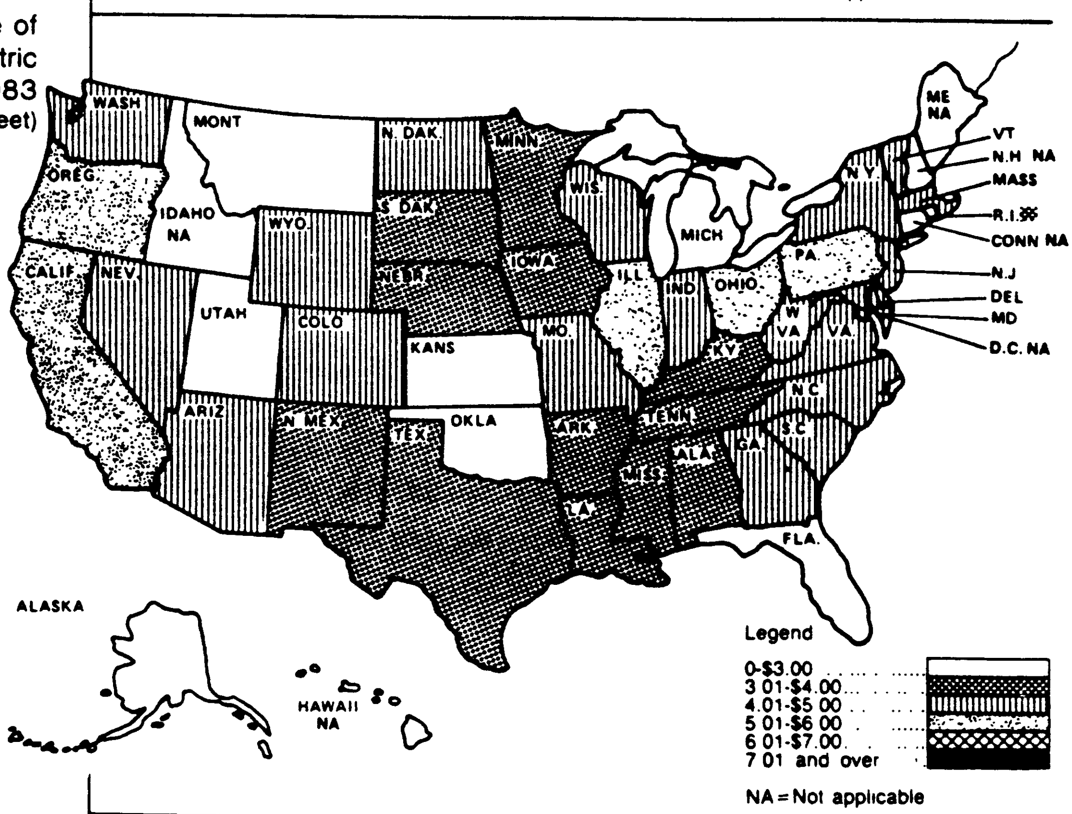


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Table 1

NATURAL GAS PRICES IN THE UNITED STATES, 1973-1984

($/Mcf)

MAJOR INTERSTATE PIPELINES

Year	Wellh'd.	Wellh'd Purchase	Indust'l. Sales	Sales for Resale	Bought by Elec. Plants	Residen-tial
1973	0.22	0.29	0.53	0.61	0.35	1.29
1975	0.45	0.41	0.73	0.83	0.77	1.71
1977	0.79	0.81	1.33	1.34	1.33	2.35
1978	0.91	0.83	1.54	1.46	1.48	2.56
1979	1.18	1.22	2.01	1.85	1.80	2.98
1980	1.59	1.63	2.53	2.52	2.28	3.68
1981	1.98	2.15	3.11	2.93	2.91	4.29
1982	2.46	2.72	3.73	3.72	3.49	5.17
1983	2.59	2.93	4.25	4.10	3.58	6.06
1984 Jan	2.72	2.80	4.25	3.86	3.56	5.98
1984 Jul	2.58	2.95	4.04	4.12	3.86	6.17
1984 Oct	2.60	2.96	4.06	4.09	3.74	6.25

Note: 1973-77 data are not strictly comparable with 1978-83 data in all cases.

Sources: DOE/EIA, Monthly Energy Review, January 1983; idem., Natural Gas Monthly, December 1984.

Table 2

U.S. OIL PRICES, SELECTED YEARS, 1976-1984
(per 10^6 Btu)

	No. 6 High Sulfur	No. 6 Low Sulfur	No. 2 Distillate
1976	$1.66	$1.99	$2.66
1979	2.61	3.37	4.10
1980	3.52	4.95	5.79
1981	4.45	6.25	7.04
1982	4.11	5.78	6.59
1983	4.64	4.64	5.88
1984	4.40	4.81	5.92

SOURCE: Monthly Energy Review

COST OF FOSSIL FUELS TO ELECTRIC GENERATION PLANTS
(per 10^6 Btu)

	Coal*	No. 6*	Gas
1973	$0.40	$0.79	$0.34
1976	0.85	1.96	1.03
1979	1.22	3.00	1.75
1980	1.35	4.28	2.21
1981	1.53	5.29	2.82
1982	1.65	4.76	3.41
1983	1.66	4.58	3.47
1984	1.66	4.81	3.58

*Both high- and low-sulfur content.

SOURCE: Monthly Energy Review

U.S. AVERAGE ELECTRICITY COSTS, BY CONSUMER CLASS, SELECTED YEARS, 1973-1984
(per 10^6 Btu)

	Residential	Commercial	Industrial	TOTAL
1973	$ 7.44	$ 7.06	$ 3.66	$ 5.74
1976	10.93	10.81	6.48	9.06
1979	13.60	13.72	8.94	11.69
1980	15.71	16.06	10.81	13.86
1981	18.17	18.43	12.57	16.00
1982	20.10	20.10	14.51	17.96
1983	21.04	20.54	14.57	18.43
1984	22.16	21.48	14.74	19.11

SOURCE: Monthly Energy Review

noted at the outset, to answer this question requires considerable intuition and some crude guesswork. We begin with a quick look at the recent past--realizing, however, that the changes in energy markets and regulation since 1973, and more recently in gas markets since 1981, undercut the usefulness of the past as a guide to the future. Next, we present a number of forecasts or projections, more to illustrate how much lack of agreement there is than to suggest any specific numbers; at most, we can attempt to identify the main sources of the discrepancies between them. Finally, we discuss the factors that will shape the outlooks for gas demands, and for the Canadian role in meeting them, both generally and in each of our three regions (Pacific, Midwest, and Northeast).

5.1 Some Recent Evidence

Figure 4 and Tables 1 and 2 provide national and regional information on the prices of natural gas and its main substitutes. Figure 4 reveals the favorable geographical situation of Canadian gas suppliers, compared with their Mexican counterparts, in being located closer to the higher-priced parts of the U.S. gas market. (Note that "white" coloration sometimes denotes zero sales, not the lowest average price.) Table 1 clearly shows the watershed character of the national Gas Policy Act of 1978, which contributed significantly to the decontrol of U.S. wellhead gas prices. Table 2 records the recent histories of prices for residual and distillate fuel oil that have created so much downward pressure on gas prices. Also, natural gas still has a cost (per MMBtu) advantage over residual fuel oil, but it has declined noticeably since 1973. The cost/MMBtu of coal ignores higher costs of use and environmental objections. Still, there is economic pressure to consider using coal in new electric generating capacity. Finally, the data on electricity rates in Table 2 illustrate why utilities have become interested in "combined-cycle" gas-fired generation capacity, with backstop gasifiers possible, when the promised cheap nuclear-generated power failed to materialize. (See David White's discussion of the potential for combined-cycle electric generation.)

Table 3 depicts dramatically what has happened to the U.S. natural gas industry since 1981. The variations in residential and commercial deliveries were heavily driven by variations in weather. In contrast, industrial and electric utility use were driven by (1) the Great Recession; (2) conservation; (3) structural change in the composition of output; and (4) relative-price substitution.

The last factor will always constitute a threat to gas demand, in the short as well as long run. If anything, the proportion of gas demand that is vulnerable to oil price declines will only increase over time. In some quarters, one finds the view that conservation and structural change not only were quite significant but also produced substantial long-term reductions in gas use compared with earlier projections. Indeed, if we assume that the 1982-84 changes in industrial and electric-utility gas use capture the full recovery from the Great Recession, a permanent loss of some 1,500 Bcf is attributable to conservation, structural change, and substitution.

In April 1985 the American Gas Association estimated that nearly all of the switchable gas load in electric generation and most of the switchable industrial load had been recovered. Also, several interstate pipelines report having recovered virtually all of the loads they lost to residual fuel oil due to price movements in 1982-83.

As for conservation, a recent DOE study reports industrial energy conservation proceeding at rates substantially greater than were forecast in 1980. The open question for the long term is how long it will take firms to complete their conservation investments. The picture is clouded by the

Table 3

U.S. NATURAL GAS DELIVERIES BY CUSTOMER CLASS

	Total Delivery (bcf)				Percent Change		
	1981	1982	1983	1984	81-2	82-3	83-4
Residential	4546	4633	4381	4331	+1.9	-5.4	-1.1
Commercial	2520	2606	2433	2370	+3.4	-6.6	-2.6
Industrial	7128	5831	5643	6108	-18.2	-3.2	+8.2
Elec. Util.	3640	3226	2911	3113	-11.4	-9.8	+6.9
Total Deliveries	17834	16295	15367	15926	-8.6	-5.7	+3.6

Source: DOE/EIA, Natural Gas Monthly, January 1985 (published March 1985) increasing conviction that real energy prices may be falling, not rising as also forecast in 1980. Thus, conservation investment might drop off for a while but undergo a resurgence if real energy prices begin to rise again. It is interesting to note that conservation investment may be greater if economic growth is stronger; if so, the increased energy (and gas) demand from the former would be offset by the latter.

Tables 4 and 5 present data on U.S. national and regional gas consumption, 1979-83, together with average prices by category of use. Note for later reference the rather pronounced declines in industrial and electric-utility use in the Pacific and Midwest markets, and the striking gains in electric-utility use, plus the less dramatic drop in industrial use, but still nearly 10%, in the Northeast market.

Table 6 shows the degree to which natural gas has "saturated" the home-heating markets in different U.S. regions. What we are calling the Northeast market (New England and Middle Atlantic) shows the lowest saturation, around two-thirds of the market; thus, there is some potential for residential growth there. However, this region has one of the slowest population growth rates in the nation. Moreover, the economics of converting to gas from distillate fuel oil (the main competitor) are not nearly so attractive as they were even five years ago, given the capital cost plus recent trends in relative costs per MMBtu (see Tables 2 and 4).

Tables 7-9 portray recent developments in gas use by industrial and electric-utility customers, including breakdowns by Standard Industrial Classification (SIC) codes for heating years (April 1-March 31) from 1979-80 through 1983-84. All industries show clear signs of the 1981-82 recession, but many also show clear evidence of structural change, conservation, and relative-price substitution. The top 20 SICs for large-user gas consumption

Table 4

NORTH AMERICAN NATURAL GAS CONSUMPTION, BY REGION AND CONSUMER CLASS, 1979-1983

	Residential		Commercial		Industrial		Electric Utilities	
	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price
Overall U.S. Market								
1979	5144.0	2.98	2776.7	2.76	6973.2	2.03	3275.0	1.78
1980	4868.5	3.75	2610.4	3.51	7135.3	2.54	3591.9	2.11
1981	4654.2	4.28	2490.2	4.01	7027.9	3.09	3775.2	2.91
1982	4708.9	5.16	2574.0	4.80	5701.6	3.88	3274.6	3.49
1983	4429.5	5.88	2438.4	5.43	5667.6	4.27	3016.0	4.00
Pacific Market								
1979	668.3	2.61	350.2	2.88	590.8	2.76	430.7	2.58
1980	613.0	3.68	342.4	4.13	507.2	3.91	529.4	3.71
1981	561.0	3.94	290.5	4.52	526.2	4.15	744.7	4.21
1982	613.5	4.66	322.3	5.48	412.6	5.01	570.6	5.29
1983	567.2	5.36	266.4	6.15	428.5	5.26	491.0	5.11
Midwest Market								
1979	1943.8	2.81	1001.0	2.59	1706.4	2.28	108.0	2.06
1980	1844.6	3.41	936.5	3.36	1574.1	2.90	85.4	2.56
1981	1756.5	3.97	904.1	3.74	1541.3	3.40	55.6	3.14
1982	1761.8	4.81	926.0	4.50	1306.1	4.14	39.5	3.66
1983	1610.5	5.54	854.2	5.10	1216.9	4.61	33.7	4.64

Sources: Royal Bank of Canada; Canadian Gas Association; DOE Energy Information Administration; <u>Monthly Energy Review</u>; American Gas Association

NOTE: These data <u>exclude</u> "lease and plant fuel" and "pipeline fuel."

Table 4 (cont.)

NORTH AMERICAN NATURAL GAS CONSUMPTION, BY REGION AND CONSUMER CLASS, 1979-1983

	Residential		Commercial		Industrial		Electric Utilities	
	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price
Northeast Market								
1979	912.6	3.91	389.3	3.50	528.8	2.73	76.2	2.50
1980	916.8	4.70	432.9	4.26	519.3	3.36	237.4	2.91
1981	933.2	5.41	442.4	4.88	576.9	4.07	236.4	3.80
1982	917.4	6.48	452.9	5.73	507.7	4.90	246.2	4.15
1983	865.7	7.29	432.8	6.52	477.7	5.18	273.5	4.37
Mid-Continent Market								
1979	1004.4	2.63	672.6	2.56	3075.4	1.61	2403.4	1.64
1980	891.0	3.10	555.0	2.92	3495.2	2.03	2440.5	1.73
1981	806.9	3.80	499.4	3.52	3336.6	2.54	2463.0	2.53
1982	850.6	4.73	526.6	4.17	2560.5	3.31	2149.7	3.09
1983	829.6	5.28	528.9	4.84	2675.5	3.83	1960.9	3.81
Southeast Market								
1979	601.9	3.17	346.4	2.74	992.8	2.27	232.2	1.57
1980	594.4	3.80	338.9	3.35	980.6	2.83	265.3	1.84
1981	587.9	4.48	343.0	4.00	984.3	3.52	253.0	2.17
1982	554.9	5.44	334.3	4.86	856.5	4.27	245.4	2.51
1983	545.7	6.22	337.2	5.50	804.4	4.50	225.3	3.25

Sources: Royal Bank of Canada; Canadian Gas Association; DOE Energy Information Administration; Monthly Energy Review; American Gas Association

Table 4 (cont.)

NORTH AMERICAN NATURAL GAS CONSUMPTION, BY REGION AND CONSUMER CLASS, 1979-1983

	Residential		Commercial		Industrial	
	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price
Overall Canada Market						
1979	338.9	3.46	327.0	2.96	853.5	2.40
1980	339.4	3.98	357.2	3.31	830.3	2.74
1981*	408.4	5.05	337.6	4.20	775.2	3.53
1982	443.6	4.87	364.8	4.20	780.4	3.61
1983	409.6	6.78	342.0	4.80	824.6	3.97
Western Canada Market						
1979	157.5	2.55	129.7	2.13	414.6	1.67
1980	155.9	2.94	148.0	2.43	398.8	1.99
1981*	176.2	3.73	149.6	3.09	400.4	2.57
1982	212.1	4.39	176.1	3.88	395.0	3.17
1983	187.9	5.21	151.9	4.32	412.6	3.41
Eastern Canada Market						
1979	181.4	4.25	197.3	3.50	454.7	2.99
1980	183.5	4.87	209.2	3.94	431.5	3.43
1981*	201.7	6.18	193.6	5.00	415.5	4.42
1982	231.5	7.05	188.7	6.01	385.4	5.42
1983	221.7	8.12	190.1	6.57	412.0	6.04

Sources: Royal Bank of Canada; Canadian Gas Association; DOE Energy Information Administration; Monthly Energy Review; American Gas Association

*Converted from NEB estimates in patajoules at 948,213 Mcf per Pj. Regional estimates derived from approximate shares for other years.

Table 5

TOTAL NORTH AMERICAN NATURAL GAS CONSUMPTION AND AVERAGE PRICES, SELECTED YEARS, 1973-1983

	UNITED STATES TOTAL		PACIFIC MARKET		MIDWEST MARKET		NORTHEAST MARKET		MID-CONTINENT MARKET		SOUTHEAST MARKET	
	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price
1973	21,327.1	.73	2,441.2	.77	5,172.5	.87	2,143.6	1.37	8,709.2	.44	2,787.0	.81
1976	19.383.1	1.45	1,991,1	1.67	4,927.5	1.57	1,947.5	2.36	8,255.0	1.12	2,170.8	1.47
1979	19,386.3	2.35	2,075.1	2.69	4,923.7	2.54	2,021.4	3.41	7,857.7	1.85	2,385.4	2.49
1980	19,560.9	2.93	2,123.5	3.82	4,626.7	3.16	2,245.5	4.21	8,053.4	2.20	2,405.4	3.03
1981	19,297.4	3.48	2,217,2	4.17	4,406.5	3.70	2,296.5	4.73	7,867.3	2.78	2,401.5	3.65
1982	17,400.3	4.33	2,009.0	5.04	4,179.6	4.52	2,246.0	5.66	6,683.0	3.54	2,175.6	4.56
1983	16,732.2	4.98	1,832.4	5.46	3,890.4	5.13	2,208.3	6.47	6,595.3	4.28	2,079.8	5.07

	CANADIAN TOTAL		W. CANADIAN MARKET		E. CANADIAN MARKET		NORTH AMERICAN TOTAL	
	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price	Bcf	Avg Price*
1973	1229.4	.87	523.7	.63	705.7	1.04	22,556.5	.74
1976	1370.8	1.84	552.4	1.23	818.4	2.27	20,753.9	1.48
1979	1535.4	2.73	701.9	1.95	833.5	3.39	20,921.7	2.38
1980	1527.0	3.16	702.8	2.31	824.2	3.88	21,087.9	2.95
1981*	------	----	714.9	3.00	806.2	5.02	20,816.6	3.52
1982	1554.7	4.88	757.4	3.67	797.3	6.04	18,955.0	4.38
1983	1547.3	5.49	732.2	4.04	815.1	6.80	18,279.5	5.02

*In US$/1000 cf

Pacific Market: CA, OR, WA, and ID
Midwest Market: ND, SD, NE, MN, WI, IA, IL, IN, MI, OH, and MT
Northwest Market: ME, NH, VT, MA, RI, CT, NJ, NY, and PA
Midcontinent Market: AZ, CO, NV, NM, UT, WY, AR, LA, OK, TX, MO, and KS
Western Canadian Market: BC, Alta., and Sask.
Eastern Canadian Market: NB, Que., Ont., and Man.

Note: These data include "lease and plant fuel" and "pipeline fuel."

SOURCES: Canadian Gas Association; Royal Bank of Canada; American Gas Association; Energy Information Administration; U.S. Department of Energy

*Converted from NEB estimates in patajoules at 948,213 Mcf per Pj.
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Table 6

GAS UTILITY INDUSTRY HOUSEHEATING CUSTOMERS AND HEATING SATURATIONS[a] BY CENSUS DIVISION, 1960-1983 YEARLY AVERAGES[b]

(Thousands)

Census Division	1960 Customers	1960 Percent	1965 Customers	1965 Percent	1970 Customers	1970 Percent	1975 Customers	1975 Percent
United States	**20,739**	**68.2**	**26,297**	**76.1**	**31,209**	**81.9**	**34,372**	**84.1**
New England	386	25 3	583	36 8	779	48 6	857	54 8
Middle Atlantic	2,475	35 1	3,212	43 2	3,827	50.3	4,128	54 1
East North Central	4,369	64.3	6,091	77 6	7,528	85.6	8,432	89 4
West North Central	1,999	82 6	2,485	88 6	2,916	92 2	3,261	94 5
South Atlantic	1,533	66.7	2,073	74 9	2,599	80 9	2,970	84 2
East South Central	1,161	87 4	1,422	92 4	1,695	96 4	1,868	96.5
West South Central	3,457	99 7	3,900	99 5	4,278	99 0	4,496	97 1
Mountain	1,081	95 5	1,366	96 4	1,646	97 3	2,040	98.0
Pacific	4,278	97 3	5,165	97 3	5,941	98 3	6,320	94.6

Census Division	1980 Customers	1980 Percent	1981 Customers	1981 Percent	1982[R] Customers	1982[R] Percent	1983 Customers	1983 Percent
United States	38,163	87.8	38,979	88.3	39,285	88.2	39,799	88.7
New England	1,009	63 1	1,069	65 9	1,090	66.8	1,080	65.8
Middle Atlantic	4,515	60 0	4,658	61 6	4,750	62.5	4,842	63.3
East North Central	9,166	92 1	9,392	93 3	9,471	93.8	9,503	93.9
West North Central	3,590	96 3	3,685	96 7	3,733	97.3	3,751	96.9
South Atlantic	3,313	89 4	3,433	90 6	3,491	90.9	3,525	90.5
East South Central	1,965	98.5	1,969	98 0	1,982	98.3	1,976	97.0
West South Central	4,998	99.5	5,068	99 4	4,992	95.9	5,153	98.0
Mountain	2,406	98 2	2,503	98 5	2,546	98.8	2,570	98.5
Pacific	7,201	95.8	7 202	94 1	7,230	93 4	7,405	94 6

a. Percentages refer to proportion of total residential customers, within specified areas, using gas for heating.
b. Excludes data for Alaska prior to 1961 .
R – Revised
Source: A.G.A. *Gas Househeating Survey*. Data represent average number of customers developed from number of year-end customers as shown in survey.

Table 7

U.S. INDUSTRIAL AND ELECTRIC UTILITY GAS CONSUMPTION, 1979-1983

	Industrial and Electric Utility Gas Consumption			Gas Consumption by "Large End Users"*		
	(2) Industrial	(3) Electric Utility	(4) Total	(5) Total	(6) Largest 20 SIC Codes	(7) Electric Util's (SIC 49)
1979	6899	3491	10390	9117	8857	3071
1980	7172	3682	10854	8834	8617	3167
1981	7128	3640	10822	8666	8448	3210
1982	5831	3226	9057	7085	6910	2740
1983	5643	2911	8554	6635	6470	2440

*Yearly figures in columns 5-7 are based on "heating seasons," e.g., "1979" corresponds to April 1, 1979 to March 31, 1980.

SOURCES: Columns 2-4: DOE/EIA, Natural Gas Monthly, March 1985.
Columns 5-7: DOE/EIA, Natural Gas Annual, 1983, Volume II.

Table 8

Deliveries of Natural Gas
to the Top 20 Industries
1979/80-1983/84
(2-digit SIC, Large End Users)

Industry	SIC Code	1979-1980	1980-1981	1981-1982	1982-1983	1983-1984
Elec Util	49	3,071.2	3,167.4	3,210.2	2,740.3	2,440.5
hemical	28	1,599.5	1,633.5	1,551.9	1,266.2	1,173.0
etrol Ref	29	780.8	862.5	759.3	686.7	639.4
Prim Metals	33	1,065.9	883.8	876.1	576.7	590.7
Stone, etc	32	534.9	431.0	365.3	313.3	311.1
Paper	26	373.5	346.4	394.0	303.3	303.0
ood	20	360.8	340.6	330.5	305.3	277.0
rans Equip	37	166.5	139.8	123.6	101.5	115.5
Fab Metals	34	112.0	102.6	102.4	75.4	83.1
Hospitals	80	139.9	112.9	96.9	76.2	75.8
chools	82	84.0	86.4	84.8	74.6	75.2
extiles	22	74.9	63.4	65.9	57.7	63.6
Nat Security	97	67.0	61.2	59.3	59.3	56.4
Rub & Leath	30	100.8	89.9	92.5	57.6	47.9
il & Gas	13	79.4	79.5	105.9	56.3	43.6
lec Machine	36	57.2	51.1	49.8	39.9	39.6
isc Mfg Ind	39	50.4	37.6	30.4	27.2	39.4
Non-Met Ming	14	49.6	45.7	48.7	37.4	35.1
Machinery	35	54.3	47.1	46.9	31.7	31.2
umber	24	34.2	34.6	31.8	23.7	27.4
Total Deliveries o Top 20 Industries		8,856.9	8,617.2	8,448.1	6,910.4	6,470.6
otal Deliveries to Large End Users		9,116.9	8,834.6	8,666.4	7,085.0	6,635.4

Source: U.S. Energy Information Administration, 1983 Natural Gas Annual, Volume II, 1985.

TABLE 9

Natural Gas Consumption by Large End Users, Selected States, by SIC Code, 1983

Industry	SIC	1979-80	(Interperiod Change)	1982-83	(Interperiod Change)	1983-84
	MICHIGAN					
Paper	26	28.5	-06%	26.9	-46%	14.4
Chemicals	28	23.1	-48%	12.1	-26%	8.9
Metals	33	28.4	-24%	21.5	-20%	17.2
Metal Prod.	34	13.4	-27%	9.8	-35%	6.4
Trans	37	78.3	-25%	58.7	-15%	50.7
Elec. Util.	49	30.9	-42%	18.0	-28%	13.0
TOTALS		272.7	-25%	203.4	-24%	154.7
	NEW JERSEY					
Food	20	2.6	42%	3.7	05%	3.9
Paper	26	3.0	220%	9.7	-43%	5.5
Chemicals	28	12.1	49%	18.2	-36%	11.7
Stone, Clay	32	19.9	-03%	19.3	-14%	16.7
Metals	34	5.0	12%	5.6	-39%	3.4
Elec. Util.	49	14.1	46%	20.6	23%	25.3
TOTALS		71.7	44%	103.0	-24%	79.0
	NEW YORK					
Food	20	6.7	25%	8.4	-05%	8.1
Paper	26	2.5	80%	4.5	-22%	3.4
Chemicals	28	9.0	14%	10.3	-32%	7.0
Stone, Clay	32	12.5	-12%	11.0	-04%	10.6
Metals	34	20.0	-08%	18.3	-56%	8.1
Elec. Util.	49	14.1	44%	20.3	-32%	13.9
TOTALS		104.0	11%	115.9	-25%	86.4
	ILLINOIS					
Food	20	42.8	-08%	39.4	02%	40.2
Chemicals	28	28.7	-20%	23.1	-19%	18.7
Stone, Clay	32	25.4	-31%	17.7	-10%	15.9
Metals	33	84.1	-21%	66.6	-32%	45.5
Machinery	35	13.1	-12%	11.5	-32%	7.9
Elec. Util.	49	19.3	-34%	12.7	-21%	10.1
TOTALS		363.8	-16%	306.5	-21%	243.1

Industry	SIC	1979-80	(Interperiod Change)	1982-83	(Interperiod Change)	1983-84
	IOWA					
Food	20	24.9	13%	28.2	-02%	27.6
Chemicals	28	35.4	-14%	30.4	-44%	16.9
Stone, Clay	32	8.3	-48%	4.3	19%	5.1
Elec. Util.	49	6.9	-81%	1.3	77%	2.3
Machinery	35	3.7	-24%	2.8	-18%	2.3
Metals	33	5.6	-11%	5.0	04%	5.2
TOTALS		108.8	-12%	95.5	-23%	73.6
	MASS					
Food	20	2.1	05%	2.2	-23%	1.7
Paper	26	1.2	41%	1.7	-30%	1.2
Chemicals	28	2.3	-26%	1.7	-18%	1.4
Stone, Clay	32	6.0	-63%	2.2	09%	2.4
Elec. Util.	49	9.4	52%	14.4	12%	32.2
TOTALS		32.8	-10%	29.5	57%	46.1
	OHIO					
Food	20	10.6	-16%	8.9	-37%	5.6
Paper	26	4.5	17%	5.2	-49%	2.7
Chemicals	28	4.5	02%	45.3	-22%	35.1
Petrol	29	10.4	-33%	7.0	-29%	5.0
Stone, Clay	32	40.2	-24%	30.6	-35%	19.9
Metals	33	12.5	-22%	97.2	-30%	67.6
Trans	37	12.8	-12%	11.1	-02%	10.9
TOTALS		292.7	-17%	241.9	-26%	176.7
	PA					
Food	20	10.8	00%	10.8	-34%	7.1
Petrol	29	30.4	-03%	29.3	-18%	24.0
Stone	32	42.0	-12%	37.1	-30%	25.9
Metals	33	170.1	-11%	152.0	-41%	89.8
Elec. Machinery	36	5.6	00%	5.6	-29%	4.0
Elec. Util.	49	3.4	106%	7.0	-44%	3.9
TOTAL		315.2	-07%	293.8	-32%	199.4

Industry	SIC	1979-80	(Interperiod Change)	1981-82	(Interperiod Change)	1983-84
	CONN					
Primary Metals	33	2.5	-40%	1.5	20%	1.8
Trans.	37	1.3	00%	1.3	23%	1.6
Stone, Clay	32	1.7	-65%	0.6	150%	1.5
Paper	26	0.2	350%	0.9	66%	1.5
TOTAL		11.3	1%	11.4	18%	13.4
	CALIF					
Elec. Util	49	502.9	31%	662.8	-31%	452.8
Pet. Refg.	29	118.4	-19%	95.5	-37%	59.8
Stone, Clay	32	62.8	-33%	42.0	-26%	30.7
Chemicals	28	52.3	-18%	42.9	-58%	17.7
Primary Metals	33	24.4	-18%	19.9	-34%	13.1
Paper	34	18.0	-28%	12.8	49%	19.1
TOTAL		892.7	11%	997.2	-33%	662.8
	IDAHO					
Food	20	7.8	02%	8.0	-16%	6.7
Paper	26	7.3	-37%	4.6	-28%	3.3
Chemicals	28	10.4	-23%	8.0	-66%	2.7
TOTAL		28.4	-20%	22.6	-40%	13.4

Table 10

U.S. GAS IMPORTS FROM CANADA, SELECTED YEARS, 1973-1983

	1973	1976	1979	1980	1981	1982	1983	Authorized 1983 Volumes	1983 Actual/Auth. (%)	1984	Authorized 1984 Volumes	1984 Actual/Auth. (%)
PACIFIC MARKET												
Imports	705.2	653.5	670.7	506.5	438.2	430.2	398.1	962.8	41.3%	389	872	44.6%
MIDWEST MARKET												
Imports	312.5	290.5	316.4	553.0	597.8	594.3	524.5	1344.4	39.0%	332	890	37.3%
Exports	(14.8)	(7.5)	(0.1)	(282.4)	(305.4)	(270.0)	(236.2)					
Net Imports	297.7	283.0	316.3	270.6	292.4	324.2	288.3					
NORTHEAST MARKET												
Imports	9.4	9.6	13.7	19.1	31.6	28.6	27.0	78.6	34.4%	34	64	53.1%
TOTAL U.S.												
Imports	1027.1	953.6	1000.8	1078.6	1067.6	1053.1	949.6	2385.8	39.8%	755	1826	41.3%
Exports	(14.8)	(7.5)	(0.1)	(282.4)	(305.4)	(270.0)	(236.2)					
Net Imports	1012.3	946.1	1000.7	796.2	762.2	783.1	713.9					

Sources: Canadian Gas Association; Royal Bank of Canada.

NOTE: All columns are in Bcf unless otherwise noted.

(Table 8) also include the 10 most energy-intensive SICs. According to the recent DOE report cited above, 9 of those 10 met or exceeded the energy conservation targets set in 1980. Only Paper and Allied products, Code 26, failed to meet its target, barely missing it by 1.2 percentage points out of a targeted 20 percent reduction. However, this industry's total annual gas use in 1983-84 was down some 70 Bcf, or nearly 20 percent, from the 1979-80 figure.

Of all the factors affecting prospects for future gas demand, structural shifts in the composition of U.S. industrial output are the hardest to gauge. It seems as though the steel, auto, and rubber industries are unlikely to reattain their previous rates of output. Many people are pessimistic about chemicals and petroleum refining (looking at existing excess capacity and the facilities now abuilding in several oil-exporting nations), and oil and gas extraction will suffer if crude oil prices remain soft. Some offsetting might occur if the so-called "overvalued" U.S. dollar declined and made some ailing U.S. industries more competitive.

Table 10 shows Canadian gas exports to each of our three U.S. market regions for 1973, 1976, and 1979-84. Also shown are the 1983 authorized volumes and the percentage of them that was actually delivered in that year. The Midwest market shows the beginning of "intransit" gas exports (to be reimported) on a major scale in 1980.

5.2 Some Forecasts and Projections

Tables 11 and 12 summarize a number of forecasts of Canadian and U.S. natural gas consumption over the next 15 years. The estimates for Canada are reasonably consistent, even to the time profile of the growth rate of gas use (compound annual percentage rate):

Table 11

FORECAST OF CANADIAN NATURAL GAS CONSUMPTION,
BY CUSTOMER CLASS, 1983-2000 (Bcf)

Year	Residential	Commercial	Industrial	Electric Utility	TOTAL	N.E.B. Total**
1983	410.8	333.0	776.2	59.8	1579.8	1553.2
(1983 actual)*	(401.5)	(335.6)	(810.0)		(1547.1)	
1984	443.1	329.2	829.3	59.8	1661.4	1592.0
1985	452.6	322.6	879.8	59.8	1714.8	1667.0
1986	474.4	317.8	921.2	59.8	1773.2	1732.4
1987	494.3	319.7	955.4	55.0	1824.4	1781.7
1990	551.2	323.5	1034.1	56.0	1964.8	1936.3
2000	670.8	414.6	1352.0	49.3	2486.7	2428.4

Source: Royal Bank of Canada, The North American Natural Gas Industry, 1984; N.E.B., Canadian Energy Supply and Demand 1983-2005, Technical Report, Ottawa, Canada, 1984.

* Canadian Gas Association, Canadian Gas Facts, 1984. Electric utility consumption is included in Industrial consumption.

** Projection of "net sales" in Canada. Converted from petajoules at 948,213 Mcf.

Table 12

FORECASTS OF U.S. NATURAL GAS CONSUMPTION,
BY CUSTOMER CLASS, SELECTED YEARS
(Bcf)

A.)	Residential	Commercial	Industrial	Electric Utility	TOTAL
1983	4429.5	2438.5	5667.6	3016.0	15551.6
(1983 actual)*	(4381.0)	(2433.0)	(5643.0)	(2911.0)	15368.0
1984	4538.4	2499.8	6087.4	2862.8	15988.4
(1984 actual)*	(4331.0)	(2370.0)	(6108.0)	(3113.0)	15922.0
1985	4487.6	2495.5	5950.7	2771.1	15704.9
1986	4482.2	2490.5	6000.3	2619.4	15592.4
1987	4495.2	2505.3	6015.1	2520.6	15536.2

B.)	Residential	Commercial	Industrial	Electric Utility	
1990	5200	3500	8200	1900	18800
2000	5500	4000	7700	1700	18900

C.)	Residential	Commercial	Industrial	Electric Utility	
1990	4600	2700	8200	3300	18800
2000	4200	3300	7700	2200	17400

A: Gas Requirements Committee, American Gas Association.

B: Canadian Energy Research Institute.

C: Gas Research Institute.

*U.S. Energy Information Administration, Natural Gas Monthly, April 1985.

	Royal Bank	N.E.B.
1985-1990	2.75	3.00
1990-2000	2.40	2.25

Note that the N.E.B.'s overall projection from which the consumption figure is taken does foresee gas exports declining after 1990. Thus, technically speaking, increasing domestic Canadian consumption does constrain gas exports, in contradiction of our earlier assertion. However, the reason appears to be unduly conservative supply projections--in particular, the lack of explicit provision for new export permits or renewal of old ones--and hence we stick by our assertion. The Royal Bank's projections are not as pessimistic in this regard as the N.E.B.'s.

Turning to Table 12, the near-term forecast for the United States suggests essentially stable residential, commercial, and industrial demand into the late 1980s, and a noticeable decline in electric utility use. Actual experience to date does not invalidate the residential and commercial figures (which depend heavily on unpredictable weather) or that for industrial use. Electric utility gas use ran surprisingly higher--nearly 9 percent--than the projection for 1984. We cannot be sure why, but one reason may have been the unexpectedly low gas prices that prevailed in 1984 and continue to do so. There may be a lesson here for gas suppliers everywhere, including Canada.

Looking further again, the CERI forecast seems way out of line, given recent experience, for residential, commercial, and industrial uses. The same can be said of the GRI's projections for commercial, industrial, and electric utility uses--unless we assume very low natural gas prices. Most striking here, however, may be the seeming ease with which two longer-term projections can be both similar and quite different. There is a lesson here, too, for anyone trying to scope out future prospects for natural gas demand with any certainty.

Table 13 presents some estimates of Canadian gas exports over the next 15 years. All are from various government sources in Canada, two of whom asked not to be identified. There is close agreement all the way out through 1986; from 1987 on, differences on the order of 13, 12, and 21 percent appear. Note that, according to the N.E.B.'s projections, exports top out in 1990 and then decline rather rapidly; however, these figures consider only potential exports under existing licenses.

5.3 Regional Outlooks for Canadian Gas Exports

For our Pacific and Midwest regions, it would be harder to argue that total gas demand will grow between now and the year 2000 than that it will stay roughly constant or even decline.[7] It is easier to find prospects for some growth in gas demand in the Northeast region, but it would be relatively modest growth, due mainly to continued strong growth in (relatively small) industrial and electric-utility gas users.

From the Canadian perspective, the Northeast U.S. market may be the worst place to have the best growth occur. As detailed earlier, the "two-markets" organization of the North American gas industry (to which both countries' policies contributed) tends to force Canadian direct exports to New England and the Middle Atlantic states, whereas indirect exports--Canadian displacement of U.S. supplies in the Midwest, with the U.S. gas moving northeastward (including into eastern Canada)--would be economically superior. One displacement project has already been proposed, as a rival to several other direct-export projects. A forcing factor here may be U.S. producers' objections to approving displacement projects while they are shut out of the eastern Canadian market.

There is perhaps the greatest certainty about future demand prospects in the residential and commercial end-use categories. Population growth

Table 13

PROJECTIONS OF CANADIAN EXPORTS OF NATURAL GAS,
SELECTED YEARS, 1985-2000
(Bcf)

	N.E.B.*	ANON1	ANON2
1985	944	950	928
1986	1074	1050	
1987	1444	1275	
1988	1570	1400	
1989	1749	1435	
1990	1749		
1995	348		
2000	158		

Sources: N.E.B., Canadian Energy Supply and Demand, 1983-2005, Technical Report, Ottawa, Canada, 1984.

ANON1 and ANON2 are government officials in Canada.

*Converted from petajoules at 948,213/MMcf. Refers to "contract" years from November 1 - October 31. The 1985 (1984-85) figure has recently been "revised to 901 Bcf excluding short-term exports" (personel communication from a Canadian government official).

projections for the Northeast and Midwest are the lowest in the United States--in part because many of their people are moving to California. Coupled with ongoing conservation and the weakening economics of converting small space heating loads to gas from distillate fuel oil, these projections push one to doubt the financial viability of projects based on expansion in residential loads. Turning to California, where projected population growth is much higher, residential demand is expected to stay roughly constant (growing at 0.7 percent a year in the north but declining at 0.5 percent a year in the south, according to the 1985 California Gas Report (CGR). Projected commercial demand is similar, with slight growth in the north (0.1 percent a year) and stability followed by a decline (at 0.5 percent a year after 1990) in the south.

In contrast to the residential and commercial categories, the outlook for industrial use approaches is less certain. However, as indicated in our earlier discussion, those in the gas business feel they have regained most of the load lost to residual fuel oil in the 1975-83 period. Assuming this to be the case, one cannot look for substantial increased sales from recapturing. In fact, with continued weakening of real oil prices for the next few years, gas prices will need to respond to lower residual fuel oil prices to avoid a new round of volume erosion.

If this analysis is correct, the U.S. industrial sector has had a more permanent loss of 1,500 Bcf due to structural change, substitution, and conservation. The effects of these factors are difficult to quantify, but the cumulative impact is clearly in the direction of decreasing natural gas demand for at least the next several years--and perhaps through the next decade (as the California study indicated). Structural change is the most difficult to assess, but indications are that major facilities in iron and steel, automobiles, and chemicals have been shut down permanently, especially in the regions in which

Canadian gas exports play an important role. Examining interfuel competition or substitution is important in its own right, but also suggestive of the more permanent structural change. In our demand regions, residual fuel oil decreased by 30-60% even while gaining load from natural gas. The figures below show total residual fuel oil and natural gas use for the period 1979-82.

Residual Fuel Consumption (trillion Btu)

	1979	1980	1981	1982	% change 79-82
Northeast	2127.9	1917.0	1583.1	1475.5	-30.6
Midwest	571.4	416.0	304.0	216.4	-62.0
Pacific	1109.7	1075.8	964.5	666.0	-40.0

Natural Gas Consumption (Bcf)

	1979	1980	1981	1982	% change 79-82
Northeast	2021	2245	2296	2246	+11.1
Midwest	4924	4627	4407	4180	-15.1
Pacific	2075	2124	2217	2209	+ 6.5

During this same period, coal use fluctuated, but was down only slightly for the three regions.

The above comparison suggests that there is little market left for gas to recapture from residual, and that some large energy users have disappeared. Coal remains a strong competitor, and falling oil prices may make residual a more active competitor for industrial and electric utility markets for at least several years. In California, for example, the CGR projects industrial demand for gas to remain constant for the next several years. The two exceptions are cogeneration and enhanced oil recovery.

Cogeneration of electric power and heat has become popular since the early 1970s. The Public Utilities Regulatory Policies Act of 1978 (PURPA) compels utilities to buy power from cogenerators at "avoided-cost" rates. The utilities opposed the mandatory purchase of co-generated power at first, but recently they have come around to accepting and even encouraging it as an alternative to constructing new generating capacity. Some, but not all, cogeneration uses or will use natural gas. As of the end of 1984, a total of 2,716 MW of installed capacity, using more than 135 Bcf of gas per year, were in existence, according to filings with the Federal Energy Regulatory Commission required to qualify for PURPA benefits (Oil & Gas Journal, August 5, 1985, p. 50). Thus far, the biggest projects have been located in Texas, although cogeneration has begun to grow in other Gulf states and California. Like other waves of the future, installed cogeneration capacity has lagged well behind what it "should" be, based on investment analysis. In assessing its impact on regional gas demands, it is important to look at the net impact inclusive of gas use displaced by cogeneration. The economics of cogeneration in general and using gas in particular are quite sensitive to the level and structure of energy prices. Promises for cogeneration gas demand might be a flimsy basis indeed for raising financial capital for a gas venture.

The two major California gas utilities are hopeful of sizeable demand growth from cogeneration. In the northern market area, the current projection is for nearly a hundred Bcf a year by 1992, about one-eighth of total system load, and an additional 36 Bcf by 2000, giving a total load share of nearly 14 percent. The projection in the southern market area is more modest: The target for 2000 is similar, but the share of total demand is quite a bit smaller.

A good bit of the hoped-for California gas demand for cogeneration comes from enhanced oil recovery (EOR). In this process, steam is injected into heavy crude oil wells to improve their production characteristics. As noted earlier, interstate pipeline companies have filed several proposals for new capacity (filled in part with Canadian gas) to serve the california EOR market. The two major California gas utilities both hope to serve the market, too. Whether they will get part or all of the EOR gas business--and by implication whether the interstates' hopes for the market will prove out--is apparently very sensitive to rulings (expected in the autumn of 1985) by the California Public Utilities Commission (CPUC) regarding "incentive" rates and other flexible but innovative policies. The status of the interstates' EOR proposals is a matter of jurisdictional dispute between CPUC and FERC.

Prospects for gas demands from electric utilities are also fraught with uncertainties. Most projections seem to assume substantial displacement of natural gas by new nuclear or coal-fired capacity; the California PUC has an explicit off-gas (and off-oil) policy for electricity generation.[8] If this happens, it could be frustrating for gas producers (and electric-utility ratepayers) to see gas-fired generation displaced by expensive nuclear power or environmentally dirty coal-fired generation.[9] The nuclear capacity will be used, however, regardless of cost, because of financial and regulatory restrictions. The role of coal will depend on the outcome of the debate over acid rain and whether to try to control it by restricting coal use. The debate is really just beginning and promises to be a long and difficult one. It is likely to involve both the Canadian and U.S. federal governments, and provincial and state governments, too.

There may be some basis for speculating that the EOR and cogeneration markets represent a new type of gas demand that comes in a lumpier form. As indicated above, cogeneration could represent something like a 15% increase by the year 2000 in the total market for Northern California. This is a market that is likely to be dominated by 1 or 2 suppliers, since it will likely be a decision taken by the regulatory process selecting from among a number of proposals. Similarly a decision by U.S. federal or state regulators to require cleaner combustion in electric utilities in some region would give a market opportunity for gas that simply was not there. However, the electric utilities would be selecting from among alternatives for pollution mitigation, including coal cleanup, scrubbing, compliance coal use, fluid bed combustion, residual fuel oil, and natural gas. Seeking out and winning such lumpy demands will require agility in marketing and perhaps some careful calculations on the value of lower margins on large volumes compared with the certainties and risks of more general gas market trends.

The final source of potential demand for Canadian gas exports to the United States is on the supply, not the demand side. We suggested earlier that Canadian suppliers to U.S. markets could not ignore what U.S. suppliers were willing and (absent any restrictions) able to offer for sale there. Adelman and Lynch, in their paper on North American supply, find some basis for arguing that current U.S. supply levels cannot be replaced indefinitely at wellhead prices of $2.25-2.75 per Mcf, and therefore that supply prices may well trend upward somewhat over the next 15 years. Their Canadian supply outlook is somewhat more optimistic, but costs will also trend upwards. Nonetheless, this would suggest a window of opportunity to export gas further into the three U.S. regions than is currently the case. (We abstract here from non-economic, regulation-induced barriers to Canadian exports that are part of what we called the transition to competitive North American gas markets.)

The structural shifts have probably been less profound in supply than in demand, but the data are murky nonetheless. Regulation has taken its toll in disguising supply costs both in Canada and the United States. The most that can be said is probably that the difference in relative supply costs will give Canadian gas suppliers a modest, and perhaps slowly increasing chance to pick up extra business in the United States over the long term. Note that even modest, slow market penetration from this source may engender pressures from U.S. producers to restrict imports. Relaxing the policy of Canadian self-sufficiency in gas, even in eastern Canada, could be an attractive bargaining chip here. It would be a more-than-free chip, as Canadian gas consumers (and taxpayers) would likely benefit from the change. But the Venture gas sitting offshore may engender too much political opposition to permit any U.S. gas to flow into eastern Canada.

6. IMPLICATIONS OF THE ANALYSIS

North American gas markets are now demand-constrained and look like remaining so indefinitely. This implies that volumes will be much more sensitive to price than they were in the days when those markets were supply-constrained. Morevoer, the safest bet would seem to be that competition will eventually replace--in three years? five years?--regulation as the predominant governing force in market operations. As this happens, there will be a growing premium on flexibility of response to changes in market conditions. Still-regulated transactions will end up not taking place. At the same time, gas activities will be increasingly difficult for governments--federal, provincial, and state--to manage for purposes of skimming economic rents. The rents themselves will tend to get bid away by market processes.

If the foregoing accurately describes emerging North American gas markets, anyone wanting to sell gas must be ready to meet the competition, on price, timeliness, and flexibility or other contract terms. By the same token, no one willing to meet the competition will be excluded from any market.

Demands for natural gas are unlikely to experience significant growth over the next 15-20 years. Economic growth does not promise to be robust. Overall use may even decline. And (barring a solid rise in oil prices) gas has won back most of the load that switched to residual fuel oil in 1981-83. Some gains in total market size are possible from continuing deregulation of gas trading. And new technologies or activities--cogeneration, combined-cycle generation of electricity, enhanced oil recovery--may add large blocks of demand periodically. Overall, though, the demand outlook is relatively flat.

Thus, demand growth does not look like a major source of expanded North American trade in natural gas. Supply prospects may, however, have more impact.

The Canadian natural gas producing industry is relatively younger than its U.S. counterpart. From what Adelman and Lynch tell us, Canadian gas supply costs should increase somewhat less rapidly than those in the United States. Therefore, _if_ our description of the trend toward competition is correct; _if_ Canadian supply policy becomes more flexible--"market responsiveness"--and _if_ Washington erects no import barriers, _then_ Canadian sellers should be able to sell more gas in U.S. markets through price-competitiveness. In our jargon, the bank (or ridge) of Canadian-U.S. competition should shift slowly but steadily southward.

The net demand available to Canadian gas in U.S. markets could be even bigger if Ottawa were to rethink its policy of requiring that eastern demands be met out of Canadian supplies. Put differently, Canada could well sell more gas into the Pacific and Midwest regions of the United States without the constraint than it can into the Pacific, Midwest, _and Northeast_ regions with the constraint. It would be more efficient for everyone, on both sides of the border, to remove this constraint. It could also prove expeditious if it headed off retaliatory import restrictions against growing Canadian imports into the U.S. Midwest.

APPENDIX A

DERIVATION OF NET DEMANDS FOR THE ILLUSTRATIVE MODEL RUNS

Our analysis tells us that total U.S. demand for natural gas in our three regions is likely to grow only modestly at best. What growth there is will be sensitive to price, since interfuel competition will continue to be a feature of gas markets. As a base assumption, however, we postulate residual oil prices remaining constant in real terms over the next 15-20 years.

Next, we must explore the responsiveness of volumes to gas prices. We start with average delivered (burner-tip)gas prices in the three demand regions. These tend to fall between commercial on the high side and electric utilities on the lower (see Table 4); for reasons discussed above, we ignore residential prices. This yields the following base delivered prices by region:

Pacific: $5.00   Midwest: $5.00   Northeast: $6.00.

Next, recall our demand discussion illustrated by Figure 2. The question is how much quantity demanded will increase if the gas price is reduced. For this exercise, we have changed the gas price in $.25 increments; see column (1) of Table I. Column (2) assigns a percentage change in demand as a result of this price change. These numbers represent our best judgment about °price-induced demand elasticities, but are open to disagreement among even reasonable persons. Any bias is probably toward a higher demand elasticity. Column (3) gives total U.S. volumes. using a base of 2,000 Bcf in the Pacific region, 4,000 in the Midwest, and 2,300 in the East Coast.

Column (4) is our best judgment about U.S. supply response to changes in gas prices. The tables are arranged in three segments to reflect probable change in U.S. supply response over time. For the period 1985-90, the excess deliverability described in the paper by Adelman and Lynch means that the United

States is not yet on a long-run supply curve. Currently installed capacity allows U.S. production to meet some part of the increase in volumes as prices decline. We refer to this period as a demand-constrained phase. During the period 1991-94, described as the "transitional period," U.S. production is constant, neither increasing nor decreasing, and the remaining overhang of installed capacity offsets the early stages of rising costs. From 1994 on, the U.S. supply curve begins to behave in a more normal pattern, exhibiting the usual upward slope.

Column (5) gives the net demand facing Canadian suppliers. Recall that this is the total U.S. demand, less U.S. supply, at each price.

Columns (1) - (5) refer to burner-tip sales. To derive the price for Canadian gas f.o.b. the U.S. border, we have to deduct U.S. transportation and local distribution charges. Of necessity we have made a simplistic calculation of these costs for each of the three U.S. demand regions, using the following formula:

Pacific: deduct $1.90 ($.45 transport; $1.45 distribution)

Midwest: deduct $1.85 ($.50 transport; $1.35 distribution)

Northeast: deduct $2.10 ($.50 transport; $1.60 distribution)

Column (6) gives the resulting net-back prices at the border.

Columns (5) and (6) are the net demands fed into the model of North American natural gas trade (see the Blitzer-Wright paper). Different assumptions were made about growth rates over time in the various scenarios that were run.

The net demands just described are somewhat steeper in the lower than in the higher price ranges; that is, they have a "kink" in the middle. By way of testing the sensitivity of the model runs to variations in the slopes of the net demands, we also ran the model with net demands that were of roughly constant slope throughout their length--making them more elastic than those above at lower prices. In the discussion of the model runs, in Part II of the Blitzer-Wright paper, we refer to these as the "flatter" demands. Table II gives the prices and quantities for these net demands.

There is nothing wrong (or right) with these alternative net demands, except that they imply quite large quantitative increases in demand at low prices, compared with the "best-judgment" demands above. It seems to us that, to get increases in quantity demanded of this size in this price range, one must believe that there is considerable room for further penetration of natural gas in boiler-fuel uses. We offer the model results with the flatter demands to show the effects of this belief.

Table I

PACIFIC MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	2317	1660	657	$2.10
$4.25	0.030	2271	1630	641	$2.35
$4.50	0.045	2205	1600	605	$2.60
$4.75	0.055	2110	1570	540	$2.85
$5.00	0.058	2000	1540	460	$3.10
$5.25	-----	1890	1510	380	$3.35

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	2317	1560	757	$2.10
$4.25	0.030	2271	1560	711	$2.35
$4.50	0.045	2205	1560	645	$2.60
$4.75	0.055	2110	1560	550	$2.85
$5.00	0.058	2000	1560	440	$3.10
$5.25	-----	1890	1560	330	$3.35

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	2317	1485	832	$2.10
$4.25	0.030	2271	1504	767	$2.35
$4.50	0.045	2205	1523	682	$2.60
$4.75	0.055	2110	1541	569	$2.85
$5.00	0.058	2000	1560	440	$3.10
$5.25	-----	1890	1579	311	$3.35

Table I (cont.)

MIDWEST MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	4818	4100	718	$2.15
$4.25	0.030	4724	4038	686	$2.40
$4.50	0.040	4586	3975	611	$2.65
$4.75	0.050	4410	3912	498	$2.90
$5.00	0.053	4200	3850	350	$3.15
$5.25	-----	3990	3788	202	$3.40

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	4818	3950	868	$2.15
$4.25	0.030	4724	3950	774	$2.40
$4.50	0.040	4586	3950	636	$2.65
$4.75	0.050	4410	3950	460	$2.90
$5.00	0.053	4200	3950	250	$3.15
$5.25	-----	3990	3950	40	$3.40

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.020	4818	3760	1058	$2.15
$4.25	0.030	4724	3808	916	$2.40
$4.50	0.040	4586	3855	731	$2.65
$4.75	0.050	4410	3903	507	$2.90
$5.00	0.053	4200	3950	250	$3.15
$5.25	-----	3990	3998	-8	$3.40

Table I (cont.)

NORTHEAST MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.036	2679	2410	269	$2.90
$5.25	0.030	2587	2373	214	$3.15
$5.50	0.040	2512	2335	177	$3.40
$5.75	0.050	2415	2298	117	$3.65
$6.00	0.053	2300	2260	40	$3.90
$6.25	-----	2185	2223	-38	$4.15

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.036	2679	2300	379	$2.90
$5.25	0.030	2587	2300	287	$3.15
$5.50	0.040	2512	2300	212	$3.40
$5.75	0.050	2415	2300	115	$3.65
$6.00	0.053	2300	2300	0	$3.90
$6.25	-----	2185	2300	-115	$4.15

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.036	2679	2215	464	$2.90
$5.25	0.030	2587	2243	344	$3.15
$5.50	0.040	2512	2270	242	$3.40
$5.75	0.050	2415	2298	117	$3.65
$6.00	0.053	2300	2325	-25	$3.90
$6.25	-----	2185	2353	-168	$4.15

Table II

PACIFIC MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.039	2400	1680	720	$2.10
$4.25	0.045	2310	1640	670	$2.35
$4.50	0.047	2210	1600	610	$2.60
$4.75	0.055	2110	1570	540	$2.85
$5.00	0.058	2000	1540	460	$3.10
$5.25	-----	1890	1510	380	$3.35

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.039	2400	1550	850	$2.10
$4.25	0.045	2310	1550	760	$2.35
$4.50	0.047	2210	1560	650	$2.60
$4.75	0.055	2110	1560	550	$2.85
$5.00	0.058	2000	1560	440	$3.10
$5.25	-----	1890	1560	330	$3.35

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.039	2400	1480	920	$2.10
$4.25	0.045	2310	1510	800	$2.35
$4.50	0.047	2210	1528	682	$2.60
$4.75	0.055	2110	1541	569	$2.85
$5.00	0.058	2000	1560	440	$3.10
$5.25	-----	1890	1579	311	$3.35

Table II (cont.)

MIDWEST MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.040	4980	3980	1000	$2.15
$4.25	0.042	4790	3955	835	$2.40
$4.50	0.044	4595	3925	670	$2.65
$4.75	0.048	4401	3900	501	$2.90
$5.00	0.053	4200	3850	350	$3.15
$5.25	-----	3990	3788	202	$3.40

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.040	4980	3930	1050	$2.15
$4.25	0.042	4790	3940	850	$2.40
$4.50	0.044	4595	3950	645	$2.65
$4.75	0.048	4401	3950	451	$2.90
$5.00	0.053	4200	3950	250	$3.15
$5.25	-----	3990	3950	40	$3.40

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$4.00	0.042	4990	3730	1260	$2.15
$4.25	0.042	4790	3790	1000	$2.40
$4.50	0.044	4595	3860	735	$2.65
$4.75	0.048	4401	3894	507	$2.90
$5.00	0.053	4200	3950	250	$3.15
$5.25	-----	3990	3998	-8	$3.40

Table II (cont.)

NORTHEAST MARKET

DEMAND-CONSTRAINED PHASE (1985, 1988)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.037	2705	2390	315	$2.90
$5.25	0.038	2608	2358	250	$3.15
$5.50	0.040	2512	2322	190	$3.40
$5.75	0.050	2415	2298	117	$3.65
$6.00	0.053	2300	2260	40	$3.90
$6.25	-----	2185	2223	-38	$4.15

TRANSITIONAL PHASE (1991)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.037	2705	2280	425	$2.90
$5.25	0.038	2608	2290	318	$3.15
$5.50	0.040	2512	2300	212	$3.40
$5.75	0.050	2415	2300	115	$3.65
$6.00	0.053	2300	2300	0	$3.90
$6.25	-----	2185	2300	-115	$4.15

LONG-RUN SUPPLY CURVE (1994 on)

(1) DELIVERED PRICE	(2) % CHANGE IN DEMAND	(3) U.S. DEMAND (bcf)	(4) U.S. SUPPLY (bcf)	(5) NET FOR CANADA (bcf)	(6) F.O.B. PRICE
$5.00	0.037	2705	2225	480	$2.90
$5.25	0.038	2608	2248	360	$3.15
$5.50	0.040	2512	2262	250	$3.40
$5.75	0.050	2415	2298	117	$3.65
$6.00	0.053	2300	2325	-25	$3.90
$6.25	-----	2185	2353	-168	$4.15

FOOTNOTES

1. We abstract from regulatory restrictions and short-run contractual obligations that might prevent sellers from moving gas from lower to higher demand-price buyers. Such restrictions and obligations have hampered the adjustment of the North American gas market to the new market conditions it has confronted since 1981. When, or whether, they will cease to do so is still unclear. We discuss this further in Section 4.

2. We abstract from "intransit" gas flows, in which (for instance) Canadian gas crosses and then re-crosses the U.S. border en route to Canadian customers, to reduce transportation costs.

3. For instance, those of the National Energy Board published in its Canadian Energy Supply and Demand, 1983-2005, Technical Report, Ottawa, September 1984, showing "primary gas demand" (net sales in Canada plus pipeline fuel and losses, plus reprocessing fuel) growing by some 57 percent over the 20 years 1985-2005.

4. The Canadian constraint that domestic demands must be met before any Canadian gas may be exported does say this, in an extreme form: U.S. producers are effectively excluded from increasing sales in Canada at any price.

5. One analyst has argued that the NOPR, if implemented as proposed, could hurt Canadian sales to the U.S. Midwest the most. A major reason is that, under current Canadian policy, there is no demand for U.S. gas in eastern Canada. No assurance from Washington could make a difference here.

6. The FERC's recently proposed rules, discussed earlier, appear to assume this. The pricing rules would establish a separate "block" of 104 gas, with rights assigned to existing customers.

7. In the 1985 California Gas Report (CGR), for example, in the northern market area total "requirements" are projected to decline for the next five years at 1.1 percent a year, then increase at 2.2 percent a year for the next decade. In the fine print, however, the latter figure turns on winning a big share of the so-called "California EOR market," which will be using natural gas to raise steam (and cogenerate electric power) to produce heavy crude oil. This in turn requires cooperative rate and service policies from the California Public Utilities Commission to prevent one of several rival interstate pipeline projects (some involving Canadian exports) from winning the business.

In the southern market area, an upbeat outlook "more favorable than it has been for several years" turns out to mean a projected total gas demand in the year 2000 of "over a trillion cubic feet"--about what it was before the dip in 1983, but some .25 Tcf less than in 1980. And this "favorable" news likewise depends on winning a good share of the EOR market.

8. For example, according to the CGR, the start-up of nuclear capacity in California is expected to reduce gas use for electricity generation in the northern market area by 35 percent over the period 1984-86, and then cause an annual average decline of 15.4 percent through 1992. Not until then, with new capacity needed (and assumed not to be nuclear), does gas demand for electric power begin to recover--at only 12.5 percent a year through 2000.

9. The economics of combined-cycle electricity generation, using natural gas but with a medium-Btu gasifier as a backstop, appear quite strong; see David White's discussion. A capacity-selection model of electric power, constructed at M.I.T., would pick scarcely anything else in the Northeast well into the next century.

NATURAL GAS DISCOUNT RATES, PROJECT TIMING AND LONG-TERM CONTRACTS

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1. INTRODUCTION

This portion of the report discusses two sets of issues. The first regards the proper valuation of the sets of cash flows estimated to flow from investment, production, and marketing decisions under various assumptions about project timing. Section 2.1 discusses the appropriate discount rate for natural gas development and production operations. Section 2.2 examines the cost of waiting to implement the project and thus delaying sales, including the relations among the discount rate, future export price uncertainty, and a decision to delay exports. Section 2.3 discusses the value of reserving the "option" to pursue development of the project in the face of uncertain profitability. The second set of issues regards the design and valuation of the take-or-pay contracts necessary to obtain financing and to guarantee an acceptable return.

2. DISCOUNTED VALUE OF CASH FLOWS

2.1 The Discount Rate

To calculate the present value of natural gas development and production, a discount rate was calculated from market data on the riskiness of oil and gas production. A long-term real interest rate in Canada of 0.4% was used, and added to this base was a premium on risky cash flows of 10%. This risk premium is derived from data on the return to Canadian market assets and the riskiness of Canadian investment in oil and gas production using the Capital Asset Pricing Model (CAPM). A study by Dr. Michael Brennan for the Canadian Energy Research Institute is the source of the data.[1] These estimates have been checked against various other estimates for discount rates and against estimates derived from data on U.S. oil and gas companies. The estimate of the long-term real interest rate that we used was calculated as the long-term historical average of measured real rates, the difference between the short-term interest rate, and the realized rate of inflation.

Recent lower rates of inflation have made the current measured real riskless interest rate higher, around 3-4%. These data likely represent a divergence between the measured and the anticipated real riskless rate, a divergence peculiar to the current period of unusual success in controlling inflation. Calculating the real riskless rate from this recent period could lead to large estimating error. A sounder basis is obtained by looking backward over a longer period of time. Our base case for the model therefore uses the long-term average for the real interest rate. We will also exhibit some runs for the higher discount rate, 12.5%, which would obtain under the assumption of the higher real interest rate.

Recent yields on Canadian government bonds are displayed in Table 1 below. The yield curve is slightly increasing, indicating perhaps a rise in the nominal interest rate from about 10-10.5% currently to 11.1% for the very late 1990s and

[1] "Estimation of Betas and the Cost of Equity Capital, Oil and Gas Production Sector," Appendix E, The Oil and Gas Investment Climate: Changes Over a Decade, Datametrics Limited, Canadian Energy Research Institute Study No. 20, June 1984.

Table 1

Data on Canadian Federal Government Bonds, reported in the Toronto Globe and Mail, June 10, 1985

maturity date	coupon	quote	yield
jul 1-85	11.25	100.00	11.25
jul 1-85	15.50	100.25	11.25
sep 1-85	14.50	101.00	9.87
sep 6-85	10.50	100.13	9.82
Oct 1-85	10.75	100.25	9.83
Oct 1-85	12.75	100.88	9.74
Dec 6-85	9.75	99.88	10.01
Dec 15-85	8.00	99.00	10.01
Dec 15-85	9.75	99.88	9.98
Mar 6-86	10.50	100.38	9.91
Jun 6-86	13.00	102.88	9.90
Dec 15-86	10.00	100.00	10.00
Jun 1-87	13.00	104.55	10.40
Jun 1-87	14.75	107.25	10.60
Dec 15-87	11.00	101.85	10.15
Mar 15-88	10.50	100.85	10.13
Oct 15-88	10.75	101.50	10.20
Feb 15-89	6.75	90.88	9.74
Feb 15-89	11.00	102.00	10.32
Jun 1-89	13.25	108.25	10.65
Dec 15-89	11.25	103.75	10.19
Jun 1-90	11.75	104.75	10.50
Jun 1-91	11.00	102.38	10.45
Jun 1-92	10.25	100.00	10.25
Jun 1-92	15.00	119.25	10.98
Dec 15-92	11.75	105.63	10.64
May 1-93	10.75	100.88	10.58
Oct 15-93	11.75	105.63	10.71
Dec 15-93	11.50	104.50	10.68
Jun 15-94	9.50	94.50	10.46
Dec 15-94	12.50	109.88	10.81
Jun 1-95	10.50	99.25	10.62
Oct 1-95	6.50	74.00	10.72
Oct 1-95	10.00	96.25	10.60
Oct 1-95	11.25	103.25	10.72
Sep 15-96	3.00	55.25	9.58
May 15-97	9.25	90.28	10.61
Mar 15-98	3.75	57.75	9.54
Oct 15-99	9.00	88.38	10.59

Table 1 (cont.)

maturity date	coupon	quote	yield
Dec 1-99	13.50	116.50	11.17
Mar 15-00	13.75	118.13	11.20
Jul 1-00	15.00	125.13	11.46
Dec 15-00	9.75	92.50	10.75
Feb 1-01	15.75	130.38	11.51
May 1-01	13.00	113.25	11.19
Oct 1-01	9.50	92.75	10.43
Mar 15-02	15.50	129.13	11.53
May 1-02	10.00	93.25	10.88
Dec 15-02	11.25	102.13	10.97
Feb 1-03	11.75	105.75	11.00
Oct 1-03	9.50	91.00	10.63
Feb 1-04	10.25	96.75	10.65
Oct 1-04	10.50	96.88	10.89
Mar 1-05	12.00	107.13	11.10
Sep 1-05	12.25	108.38	11.13
Mar 1-06	12.50	111.75	11.04
Oct 1-06	14.00	121.63	11.29
Mar 1-07	13.75	119.88	11.28
Oct 1-07	13.00	114.63	11.20
Mar 1-08	12.75	112.75	11.21
Oct 1-08	11.75	105.75	11.05
Mar 1-09	11.50	104.00	11.02
Oct 1-09	10.75	98.86	10.88

the early 2000s. Calculations made in nominal terms and contracts fixed in nominal terms should therefore recognize this slightly increasing term Structure. This increase is very modest, however, and may not significantly affect bottom line calculations.

In other portions of this report the analysis of each development and production proposal has been broken down into seven streams of costs and revenues:

1. Investment costs, defined as those capital costs necessary to establish the capacity for production of the quantities that are projected to be produced in the coming years;

2. Operating Costs--Pools, defined as those expenditures on labor and materials and operation of the gas production facilities;

3. Operating Costs--Pipelines, defined as the variable expenditures necessary to move the produced gas for export;

4, 5, and 6. Export Revenues, defined as border receipts for sale of natural gas into the United States in three distinct markets; and

7. Royalties on Production (for Exports).

The data from which the discount rate is calculated are the set of stock market returns earned by a sample of Canadian oil and gas producers. It therefore is a measurement of the average risk experienced by these firms from the entire set of operations in which they are involved. The revenue cash flows for the projects analyzed are all export flows and do not include revenues derived from domestic Canadian sales. To the extent that export revenues are different in risk than the average revenue stream of the Canadian companies sampled, we will not have an accurate estimate of the risk associated with these flows. The measured risk is an average of the risk derived from both export operations and domestic operations. If export revenues are riskier than domestic revenues, then our discount rate will be biased downward; alternatively, if export revenues are less risky, then our discount rate will be biased upward. However, this is not likely to be a significant error.

Each of the cash flows listed is presumed to be of equal riskiness, so the single discount rate discussed above is applied to each flow. Cash flows earned in later years, though incorporating the identical discount rate, are reduced by a larger factor since the discount rate is compounded for the number of years forward that the flows are received.

One final bias should be mentioned. Oil and gas revenues represent a large portion of the portfolio of Alberta. Although much of the capital is perhaps owned by non-Albertans, be they Canadian or foreign nationals, and some of the risk in capital return has been diversified through other means, it is nonetheless certain that much of the typical Albertan portfolio is heavily invested in oil and gas. This is especially true for provincial revenues. The calculation of the discount rate mentioned above presumes that the portfolio held by the relevant decision maker is completely diversified. When, as is the case for Alberta, the portfolio is not diversified, a premium should be placed on projects that serve to diversify the portfolio, and a discount should be charged against projects that concentrate the portfolio in operations currently overrepresented. The risk inherent in gas revenues is greater for Alberta than it would be for another region less concentrated in this industry. This means the discount rate that an Alberta decision maker should use in assessing expanded or delayed oil and gas operations should be larger than the one employed here. One implication of this, as we shall see, is that earlier exploitation of the value of the gas fields should be even more preferred by Albertans than when the 10% discount rate is used.

Estimating the present value of a scenario for production and export sales involves applying discount rates to the estimated cash flows. Table 2 presents

Table 2

Base Case #1

	1991	1994	1997	2000	2003
Exports (BCF)					
west-coast	757	832	832	832	767
midwest	868	1000	1000	1000	916
east-coast	287	242	242	344	117
Export Price ($US/MCF)					
west-coast	2.10	2.10	2.10	2.10	2.35
midwest	2.15	2.24	2.24	2.24	2.40
east-coast	3.15	3.40	3.40	3.15	3.65
Export Revenues (Million $US)					
west-coast	1590	1747	1747	1747	1802
midwest	1866	2244	2244	2244	2198
east-coast	904	823	823	1084	427
Investment Charges	1030	819	1701	1699	529
Operating Costs, Pools	1400	1560	1639	1766	1638
Operating Costs, Pipelines	1291	1336	1336	1494	1064
Royalties on Exports					
west-coast	451	487	487	487	461
midwest	247	280	280	280	273
east-coast	116	103	103	137	53
Profits to Canadian Producers (Million $US)	2440	2923	2044	2072	3356
Present Value	1377	1240	651	496	604
Net Present Value	8793				
Profit to Canada (Million $US)	639	1099	138	116	1198
Present Value	361	466	44	28	215
Net Present Value	2231				

a summary of the cash flows from one possible scenario for Canadian exports. We will use this as our Case #1, with which we will compare the results of various alternative decisions. This case has been taken from one set of demand and supply figures given to the project model, and assumed that total U.S. demand remains constant through 2009. The model was used to calculate the "optimal" level of exports in every year when faced with these demand and supply figures and incorporated the discount rate of 10%. In Case #1 the export levels correspond to those which would follow under the assumptions that current royalty levels are maintained and that the Canadian government permits Canadian exporters to enter any and all markets in which the price is greater than the marginal costs of production.[2] In this Case #1, the level of exports in 1985 and 1988 is significantly greater than actual exports observed for the past two years, and the net demand curve implies that these exports are sold at $2.10, $2.15, and $2.90 at the West Coast, Midwest, and East Coast border points, respectively.

Total revenues earned in each export market are shown in Table 2 directly below the export prices in each market. Investment charges, pool operating costs, and transportation costs follow. Royalties on exports are then calculated. The sum of the three export revenue streams net of the three cost streams yields the net profits to Canada. The profit to Canadian producers is calculated by netting royalties out of the net benefit to Canada calculation. The net present value of the benefits to Canada is calculated by discounting the benefits for each year by a discount factor, $(1+r)^{t-84}$. In Table 2, we set r=10%.

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[2]This case is referred to in Part II of the Model paper as the "Reference Case." The objective function used to derive the results is referred to by Charles Blitzer in the explanation of how the model works as "Version 3."

The second scenario which we will use as a reference point for comparing alternative policies is presented in Table 3, Case #2. This case is calculated on the basis of the same demand curve and cost figures. However, the level of exports in most years is lower than that in Case #1. This may be viewed as a situation, for example, in which the Canadian government restricts the number of licenses for export; or, alternatively, a licensing condition in which the government requires a negotiated price higher than that which is seen in Case #1.[3] Although exports are restricted in Case #2 relative to Case #1, it should be noted that even in Case #2 exports in 1985 and 1988 are slightly greater than current exports.

A central question to be considered in analyzing any proposed schedule for development and production is whether the reserves should be exploited now or be held for future production. This is commonly referred to as the problem of the optimal timing of the investment or project decision. Sections 2.2, 2.3, and 2.4 each focus upon a distinct factor to be considered in assessing the effect of a decision to implement the project currently or to delay it for several years.

2.2 The Time Costs and Benefits of Delaying the Project

The costs and benefits of delaying investments until a later date are composed of two parts: the expected profit margins earned in the various possible years of operation, and the discount factor. If profit margins are close to zero for the current period, and if there is a small possibility that prices will be rising, then it would likely be wise to delay investments. This

[3]This scenario is an example of the scenario described in Part II of the Model paper as the "Restricted Imports Case." The exports in our example have been restricted, however, in every year and not just the first three, and they approximate closely the numbers for the scenario described in the Model paper as the "Maximum Benefits to Canada" case. The actual figures were derived using the objective function described in that paper as Version 1.

Table 3

Base Case #2

	1991	1994	1997	2000	2003
Exports (BCF)					
west-coast	440	440	440	440	440
midwest	585	507	507	507	507
east-coast	212	117	117	233	117
Export Price ($US/MCF)					
west-coast	3.10	3.10	3.10	3.10	3.10
midwest	2.71	2.90	2.90	2.90	2.90
east-coast	3.40	3.65	3.65	3.41	3.65
Export Revenues (Million $US)					
west-coast	1364	1364	1364	1364	1364
midwest	1584	1470	1470	1470	1470
east-coast	721	427	427	793	427
Investment Charges	286	461	983	991	653
Operating Costs, Pools	1058	1040	1121	1252	1261
Operating Costs, Pipelines	875	675	675	854	675
Royalties on Exports					
west-coast	291	290	290	290	290
midwest	205	189	189	189	189
east-coast	91	53	53	99	53
Profits to Canadian Producers (Million $US)	3479	3247	2726	2821	3087
Present Value	1964	1377	869	673	555
Net Present Value	11537				
Profit to Canada (Million $US)	1451	1085	482	530	673
Present Value	819	460	154	127	121
Net Present Value	4146				

result hinges critically upon the narrowness of profit margins assumed to currently exist--when they are close to zero, then the decision to wait involves no significant loss in profits. If, however, current profit margins are not close to zero, then the results may be reversed. A small rise in prices will only imply future profit margins a small percentage higher than current profit margins. The discount factor will likely reduce the present value of these higher margins to a fraction of the present value that would come from immediate investments. A larger rise in prices would offset the discounting effects and justify a recommendation to delay production.

Since margins are a critical element of the analysis, it is important to differentiate between the perspective of the producer whose margins are net of royalty and tax payments, and a government for which the relevant margins include the royalty and tax payments. The examples below are examined from both perspectives.

Table 4 contains calculations of the present value for Case #1 when we lower exports in 1991 and increase exports in 2003, that is, when we delay production for export. In making the calculation for Table 4 we have assumed (1) that the level of demand remains constant throughout the period of analysis, i.e., that prices are not expected to be increasing, and (2) that lowering exports in 1991 does not increase the price that Canadian producers can negotiate for the remaining supplies and symmetrically that the increased output in 2003 does not cause the price received to fall.

The results for Table 4 should be contrasted with those for Table 2. Lowering exports in 1991 by 100 Bcf lowers profits to Canadian producers in that year by $42 million (U.S.), while increasing exports in 2003 increases profits to Canadian producers in that year by $66 million. Although the nominal dollar earnings are raised by delaying exports, the net present value of the profits to

Table 4

Base Case #1 when exports in 1991 are lowered by 100 BCF and exports in 2003 are raised by 100 BCF.

	1991	1994	1997	2000	2003
Exports (BCF)					
west-coast	657	832	832	832	867
midwest	868	1000	1000	1000	916
east-coast	287	242	242	344	117
Export Price ($US/MCF)					
west-coast	2.10	2.10	2.10	2.10	2.35
midwest	2.15	2.24	2.24	2.24	2.40
east-coast	3.15	3.40	3.40	3.15	3.65
Export Revenues (Million $US)					
west-coast	1380	1747	1747	1747	2037
midwest	1866	2244	2244	2244	2198
east-coast	904	823	823	1084	427
Investment Charges	1030	819	1701	1699	529
Operating Costs, Pools	1359	1560	1639	1766	1687
Operating Costs, Pipelines	1224	1336	1336	1494	1123
Royalties on Exports					
west-coast	392	487	487	487	521
midwest	247	280	280	280	273
east-coast	116	103	103	137	53
Profits to Canadian Producers (Million $US)	2398	2923	2044	2072	3422
Present value	1354	1240	651	496	615
Net Present Value	8781				
Profit to Canada (Million $US)	538	1099	138	116	1324
Present Value	304	466	44	28	238
Net Present Value	2196				

Canadian producers is not positive--it is in fact lowered by $12 million. This is because the cash flow received in 2003 is discounted by a larger factor than the cash flow received in 1991 (5.56 in 2003, and 1.77 in 1991). The larger discount factor incorporates both the greater time cost of funds and the greater riskiness of funds to be received at a later point in time. The net present value loss from the decision to delay production is very small, essentially zero, since producers in the Table 2 scenario are exporting in 1991 at prices that exactly cover their marginal cost plus the royalty--the profit margins are close to zero. Hence the marginal cost to their profits from lowering exports in 1991 is negligible. Regardless of the discount rate, a small shift in production to later years does not significantly affect the profit to Canadian producers.

The value of delaying exports is negative, however, when the royalty payments are recognized as well. By delaying output in 1991 by 100 Bcf, the profit to Canada (profits to Canadian producers plus royalty payments) is reduced by $101 million. The increased output in 2003 raised profits nominally by $126 million, but the net present value loss to Canada is $35 million. Since the margins inclusive of the royalty are not zero, then the delay of the exports would be, in present value terms, negative from a government perspective.

The conclusion that delaying the implementation of the project will lower the present value to Canada of the project's cash flows is typical of this type of project. The key feature is the fact that the value of the project comes in the form of the revenue flows generated by production of an asset (gas). It is only when the value of the gas held appreciates sharply that it may be advantageous to delay a profitable project in order to make it yet more profitable. An example in which the appreciation factor is dominant would be an expected significant increase in future prices. Suppose, for example, that real export prices were expected to be rising 3% annually between 1991 and 2003 (in real terms). Under this assumption, and given the starting point of Case #1, a producer anticipating the price rise would delay production. Without assuming a price increase, producers were indifferent to delaying production: Clearly, then, anticipated increases in prices in the future would suffice to convince them to hold onto reserves in the ground until they could take advantage of the higher prices.

A 3% annual growth in real prices would not be sufficient, however, to make the present value of the increased profits to Canada (from a government perspective) in 2003 from delaying the exports over the present value of the sacrificed profits in 1991. Annual growth in real prices would have to rise more than 7% to increase the present value of the delayed project above that of the original scenario for Case #1.

Table 5 should be contrasted with Table 3 to demonstrate the same cost of delaying exports using Case #2 (that is, starting from a lower initial level of exports). Since marginal profits in 1991 are much larger for Case #2 than for Case #1, the loss from delaying production is larger, both in magnitude and as a percent of the Case #1 profits. Producers' profits in 1991 are lowered by $135 million in nominal terms and by $76 million in present value terms, and producers' profits in 2003 are increased by $131 million in nominal terms and by $24 million in present value terms: a net loss of $53 million in present value terms. Again, the loss from delaying exports for Canada as a whole is greater than for the producers, since the present value loss on the royalties must be added to the loss on profits. The present value to Canada is reduced by $78 million as a result of the delay in exports.

If prices were growing at a rate of 3%, as considered above, it would not be sufficient to induce producers to delay exports to the level of Case #2. To

Table 5

Base Case #2 when exports in 1991 are lowered by 100 BCF and exports in 2003 are raised by 100 BCF.

	1991	1994	1997	2000	2003
Exports (BCF)					
west-coast	340	440	440	440	540
midwest	585	507	507	507	507
east-coast	212	117	117	233	117
Export Price ($US/MCF)					
west-coast	3.10	3.10	3.10	3.10	3.10
midwest	2.71	2.90	2.90	2.90	2.90
east-coast	3.40	3.65	3.65	3.41	3.65
Export Revenues (Million $US)					
west-coast	1054	1364	1364	1364	1674
midwest	1584	1470	1470	1470	1470
east-coast	721	427	427	793	427
Investment Charges	286	461	983	991	653
Operating Costs, Pools	1019	1040	1121	1252	1379
Operating Costs, Pipelines	804	675	675	854	738
Royalties on Exports					
west-coast	225	220	220	216	270
midwest	205	254	254	248	254
east-coast	91	59	59	114	59
Profits to Canadian Producers (Million $US)	3344	3247	2726	2812	3218
Present Value	1888	1377	869	673	579
Net Present Value	11484				
Profit to Canada (Million $US)	1250	1085	482	530	870
Present Value	706	460	154	127	157
Net Present Value	4068				

justify delaying production in Case #2, a yet larger rate of growth in prices would have to be assumed, approximately 7%. Viewed from the perspective of exporting governments, a rate of growth in prices of 10% would have to be assumed for a delay in production to raise present values.

In the comparison of Table 4 to Table 2 and in the comparison of Table 5 to Table 3, we assumed that the prices at which the gas was to be sold were not altered by the decision to shift production. This might not be the case. Lowering exports in 1991 could raise prices paid to Canadian producers. Similarly, increased exports in 2003 might crowd the market and force the export price to fall. For this to happen, Canada must be facing a downward-sloping demand curve. If effects on prices in 1991 and 2003 are of equal magnitude, the decision to delay production would increase the net present value of the profits to Canadian governments and perhaps to Canadian producers, since the increased revenue in 1991 is discounted less than is the loss in 2003. The degree to which this might occur is an empirical question.

In Table 6 we have used the demand figures calculated elsewhere in this report to determine for Case #1 the amount by which prices would rise in 1991 and by which they would fall in 2003 for our alternative of shifting exports from 1991 to 2003. Based on the structure of the net demand curve given the model (see the Demand paper and Part II of the Model paper), the net present value of profits to Canada is improved by $19 million by delaying production for export and profits to Canadian producers is improved by $42 million. It therefore appears that export volumes somewhat less than those given as output for Case #1 would generate greater profits both for Canada and Canadian producers. This is consistent with the fact that the model has calculated the exports given in Case #2 as those which would maximize the profits to Canada. Our examples in this section have all considered only marginal changes in output

Table 6

Base Case #1 when 100 BCF in exports are delayed form 1991 to 2003 and the export price in 1991 rises by 25¢/MCF and in 2003 falls by 25¢/MCF

	1991	1994	1997	2000	2003
Exports (BCF)					
west-coast	657	832	832	832	867
midwest	868	1000	1000	1000	916
east-coast	287	242	242	344	117
Export Price ($US/MCF)					
west-coast	2.35	2.10	2.10	2.10	2.10
midwest	2.15	2.24	2.24	2.24	2.40
east-coast	3.15	3.40	3.40	3.15	3.65
Export Revenues (Million $US)					
west-coast	1544	1747	1747	1747	1821
midwest	1866	2244	2244	2244	2198
east-coast	904	823	823	1084	427
Investment Charges	1030	819	1701	1699	529
Operating Costs, Pools	1327	1560	1639	1766	1729
Operating Costs, Pipelines	1224	1336	1336	1494	1123
Royalties on Exports					
west-coast	392	487	487	487	521
midwest	247	280	280	280	273
east-coast	116	103	103	137	53
Profits to Canadian Producers (Million $US)	2563	2923	2044	2072	3205
Present Value	1447	1240	651	496	576
Net Present Value	8835				
Profit to Canada (Million $US)	702	1099	138	116	1107
Present Value	396	466	44	28	199
Net Present Value	2250				

from a given initial position, and the full significance can only be seen by valuing the aggregate increase in profits that would follow from delaying output to that point which would maximize Canadian profits. The exports selected by the model for Case #2 represent the best alternative available relative to Case #1. The increased price advantage resulting from lowering output appears significant, raising the present value of profits to Canada over the period by $1.915 billion. This is assuming zero growth in U.S. demand and, therefore, no exogenous expected increase in export prices.

This analysis has significant implications for Canadian government export, reserve requirements, and royalty policies. Canadian government policies will determine the extent to which private gas producers increase exports to take advantage of current market opportunities. If the structure of the net Canadian demand curve used for the cases discussed here approximates the actual demand curve faced by Canada, then Canadian producers allowed to export to any and every profitable market will produce and export at a rate in excess of that which yields the maximum benefit to Canada. They will produce the export levels given in Case #1 instead of those given in Case #2. Government policies such as restrictive export licensing arrangements, more stringent reserve policies, and/or higher royalty rates on exports, especially through the 1990s, can be used to bring the production and export decisions of producers more in line with those that are best for Canada as a whole. How these policies should be designed and what are the problems in implementing these policies is beyond the scope of this paper. This conclusion is well illustrated by the cases derived from the demand curve calculated for the model runs, but it is very robust to changes in the demand specification. The conclusion is weaker when the net Canadian demand curve is more elastic, i.e., when a small drop in price significantly increases the amount of export sales open to Canadian producers.

In the original model runs that yielded the cases discussed above, a drop in price, for example, of $0.25/Mcf from $3.10/Mcf raised export sales to the West Coast market by 129 Bcf in 1994. Our conclusion regarding the value to Canada of restrictive export policies remains strong when the elasticity of the demand curve is increased, so a drop in price of only $0.10 raises export sales to the West Coast market by 145 Bcf in 1994. To support the conclusion that the restrictive export policies do not add significantly to Canada's benefits would require an extremely flat demand curve.

Alternative assumptions regarding the discount rate could also influence the timing decision, moving the optimal timing of the investment forward or backward. If the discount rate were greater in later than in earlier years, then this increases the cost of delaying the investment project. If, on the other hand, the discount rate were lower in future years, then the cost of delaying the project might not be as high as the first calculations presented in Tables 1 and 3 would lead one to believe.

It is important to understand the situations that could be correctly represented by a larger discount rate on later cash flows. Often one imagines that a larger discount rate should be applied to later cash flows, since uncertainty is greater the further out in time one looks. It is correct that uncertainty is compounded over time, and therefore later cash flows should be reduced by a larger factor. However, in the typical discounted cash flow analysis, this is done with a constant discount rate, since the discount factor on later cash flows is compounded.

A second sense in which risk might increase in later years is through the increasing danger that competition will erode the price level at which the commodity may be sold. This element of risk is correctly incorporated not in the discount rate, but in a lower estimate of the mean revenue stream that can be anticipated from the sale of a given quantity of gas--it enters into the numerator of the discounted cash flow calculations and not in the denominator through the discount rate.

The discount rate incorporates the systematic or market risk inherent in the cash flows from the project. This captures the variance in the cash flows that an investor cannot eliminate through diversification. Later cash flows from a project may warrant a larger discount rate if there is reason to believe that the project will have more systematic or market risk in later period, that is, if there is reason to believe that the profits from the project move more closely with the rest of the market in later years than they would in earlier years. If, for example, the correlation of gas prices with market movements remained constant, but the variance in gas prices were expected to rise at some point in the future, then this would imply a higher discount rate on the stream of export revenues received after that date. The consequence of this rise in the discount rate would be a lowering of the present value of all export revenues received after that date, and therefore a raising of the cost of delaying an investment and pushing the stream of export revenues out further. Our sample runs of the model indicate, however, that for narrow changes in the discount rate this effect is not large.

2.3 The Option of Waiting to Invest

An important aspect of the decision to commit capital to developing natural gas reserves is uncertainty regarding export prices. This uncertainty has been large in recent years for almost every energy commodity and for gas in particular. Once the capital costs are committed to the development of a field, they are not reversible, even in the case of the drastic fall in the attainable export price. The previous section considered the timing decision in terms of a choice made today about the decision to commit the capital and other costs at any point in time. Table 2 presents the present value calculations of a decision made today to invest the necessary capital to sell the exports listed there, including the capital necessary for the export level for 1991. Alternatively, Table 4 presents similar calculations for a decision made today that at a point in the future (1988, for example) the capital investments needed earlier for the extra output in 1991 will be delayed to make possible the additional production in 2003 instead. Making a decision not to invest today does not entail a commitment to invest the capital at some point in the future. If the investments are delayed and export prices rise, then the investments will be made at this later date. If the investments are delayed today and export prices fall, so the profitability of the investments at the later date are also in doubt, then the investments can be further delayed. By delaying the investments, the capital costs are saved in those cases in which uncertainty in future export prices is resolved unfavorably. In the cases in which uncertainty is resolved favorably, the investments can be made and the higher value captured.

A clear example of this is in the comparison of Case #1 with the possibility of delaying exports to 2003, using the net profit to Canadian producers as our criterion of evaluation. In the comparison using Tables 1 and 3 we found that the two choices were virtually identical in present value terms. But the decision to delay exports includes the additional value, and this would weigh in the favor of delaying exports until 2003.

3. FINANCIAL CONTRACTING: TAKE-OR-PAY COMMITMENTS

Long-term delivery contracts for natural gas are typical wherever trade in natural gas is important. Although in a given country the legal and regulatory structure may have encouraged or required long-term contracts and may have specified certain forms of contracts, the regulatory structure cannot be presumed to have been the primary motivating force. It is certain that any producer and pipeline company would have an interest in using such contracts for natural gas trade independent of government regulations. The primary motive for long-term contracts in natural gas is the high fixed costs of development and the party-specific nature of the transportation system that must be constructed to deliver the gas.

Without a long-term contract to guarantee take at prices agreed upon up front, the developer would be in a poor negotiating position in attempting to sell its gas ex post. The relevant negotiating decisions will be made on the basis of marginal cost. If the contract is negotiated up front, then marginal costs will include the costs of additional units of capacity. If the contract is negotiated after capacity is installed, then the price of exchange will be determined by the marginal costs of production given the capacity, and will therefore be much lower. The developer, therefore, may in some cases not be able to recover the fixed capital costs unless it is able to negotiate the purchase and price commitments up front. Similarly, without a long-term contract between the pipeline developer and a distributor, the pipeline developer would be in a poor negotiating position in attempting to sell the gas for which it has contracted. In this case the transaction-specific nature of the capital costs becomes relatively more important than the size of the fixed costs themselves.

Although this need has long been recognized, very little effort has been made to offer quantitative assessments of the financial benefits that the producer obtains from a long-term contract. We constructed a small simulation model designed to test the financial risks borne by the producer and to quantify that portion of a project's return secured by means of take-or-pay commitments. The results will be useful in making qualitative comparisons between different projects, and will permit us to identify which projects face the greatest need for long-term commitments. The nature of the simulation is introduced in more detail in the appendix to this paper and will be completely documented in a forthcoming supplement.

One factor that would mitigate the need to negotiate long-term take-or-pay commitments is the degree of demand competition that could be expected for the resources in the future. If a pipeline could reroute supplies from one buyer to another, then, after development of a field and installation of the primary pipeline, the existence of the alternative buyer would significantly erode the ability of one buyer to negotiate downward the price of the gas.

A prime example of two projects that should be distinguished on this basis are the fields being developed in Alberta and the Venture and other east coast offshore fields. Albertan gas is able to compete in all three major export markets analyzed in this paper. Venture gas will flow into New England with little chance for sales in other markets. The number of markets open to Albertan producers decreases the risk that these producers bear for uncontracted volumes; similarly, it decreases the risks that Albertan producers bear by signing take-or-pay contracts with significantly looser restrictions. Our simulations show that the proportion of the Venture project's value that is secured by long-term contracts is larger than the proportion similarly secured for any field in Alberta. Without strong take-or-pay commitments, 10% on average of the Venture project would be lost, and therefore the profitability of the project would be entirely sacrificed. If the project were completed nonetheless, it would possibly register a loss nearly twice as great as the profit that could be anticipated were take commitments successfully negotiated.

In the Alberta fields, however, sales could in some cases be increased if the requirement for take-or-pay commitments were abandoned, but the anticipated profitability of a project in the field would fall by 50%, since prices that the producer could successfully negotiate in future years of operation would be much lower than those concluded in the older take-or-pay contracts. The most important result is the qualitative difference between the Venture and the Alberta fields. In the Venture fields the significance of the take commitments is much greater than in Alberta--an order of magnitude greater. One expects that successful operations and marketing in the Alberta (as opposed to the Venture) fields will therefore involve less dependence upon the typically rigid and heavy take contracts that have been common in the past.

These forces have shown themselves in changes that have been occurring in natural gas markets in past years. Recent contracts for delivery of gas in the United States and from Canada to the United States have included significantly lower take-or-pay commitments relative to the size of the field and the expected annual sales (see Table 7). The total number of contracts closed has been small, so it is difficult to discern if this represents a significant and permanent change in the nature of contracts being signed. The reason to believe that this change is at least in part permanent is the fact that the number of potential customers to whom gas may be routed has grown significantly, and this has caused a significant decrease in the size of the up-front commitment necessary to assure a satisfactory price on sales negotiated after the high fixed costs have been incurred. These forces are particularly strong for Albertan gas being sold to markets in the United States. Recent efforts to promote short-term sales and spot markets of some form are additional, albeit weak, indicators of these forces.

Table 7

Summary of Take-or-Pay Provisions by NGPA Section and Vintage[a]

NGPA Section and Vintage	Weighted Average Percent Take Requirement
NGPA Section	
102 Onshore	87.2 (0.03)
102 Offshore	90.4 (0.01)
103	80.1 (0.02)
107	75.8 (0.04)
108	97.8 (0.02)
105/106(b)	75.9 (0.03)
104/106(a)[b]	92.0 (NA)
Vintage[c]	
Pre-1973	78.1 (0.08)
1973-April 20, 1977	94.0 (0.03)
April 20, 1977-11/8/78	88.0 (0.02)
November 9, 1978-1979	86.8 (0.02)
1980	79.0 (0.02)

[a]Coefficients of variation are contained in parenthesis beside value presented; see footnote a, Table 4, for an explanation of these statistics.

[b]Data on 104 and 106(b) data are not based on the Form EIA-758 data but the study published in December 1981 [2].

[c]These data on vintage do not include Section 104 and 106(a) data.

NA = Not available.

From: Natural Gas Producer/Purchaser Contracts and their Potential Impacts on the Natural Gas Market, US Department of Energy, EIA Office of Oil and Gas, June 1982

The large surplus of deliverable gas is yet one more force suggesting that suppliers should be willing to negotiate contracts with much lower take requirements: Profits on developed and deliverable reserves do not benefit significantly from long-term contracts. This, of course, helps to explain the willingness of many suppliers on both sides of the border to take advantage of the various extraordinary pricing programs: Special Marketing Programs and Variable Related Incentive Program (SMPs and VRIP). Of course, while Albertan producers may be well advised to experiment with ways by which they may impose lower take requirements on customers, this does not mean that they should be willing to accept a relaxation of current commitments.

Inherent in the decision to negotiate a long-term contract is the need to set quantities and prices for the agreed-upon deliveries. The choices of prices and quantities at which gas will be delivered under various circumstances and prevailing market conditions necessarily determine which party will accept the risks associated with the project. If, for example, the producer is able to negotiate a fixed price, then the purchaser will have taken on the price risk associated with the project. Due to the need to use long-term take-or-pay contracts as a means of avoiding opportunism in later purchases, and due to the lack of a spot market for natural gas to which the contracted price might be tied, it has usually been necessary to fix the price for the term of the contract. As a result, the long-term take-or-pay contract has necessarily transferred some of the pricing risk to the purchaser. This is not a result for which the contracts were designed and implemented. It is difficult to imagine a reason for which the purchaser should be the bearer of the pricing risk. The assignment of the pricing risk to the purchaser is not a desirable arrangement. It is a necessary result of the need to arrange a commitment from the purchaser in order to avoid opportunistic negotiating after the fixed costs have been incurred. This commitment takes the form of take-or-pay contracts with fixed-price provisions, and therefore it shifts the pricing risk. This risk would presumably better lie with the producer as the entrepreneur who should be involved in risking capital funds for production of the least-cost source of energy.

A take-or-pay contract therefore necessarily and unfortunately restricts the flexibility of the purchaser in adapting its purchases of each type of input to fluctuations in the relative market values of different energy supplies or to fluctuations in the demands for the natural gas due to fluctuations in weather or industrial activity in a region or territory. Purchasers therefore will be hesitant to enter into take-or-pay commitments or will enter into them only to the extent that they feel assured that given the contingencies in which the commitment will force losses upon them, the contract as a whole assures them a profit.

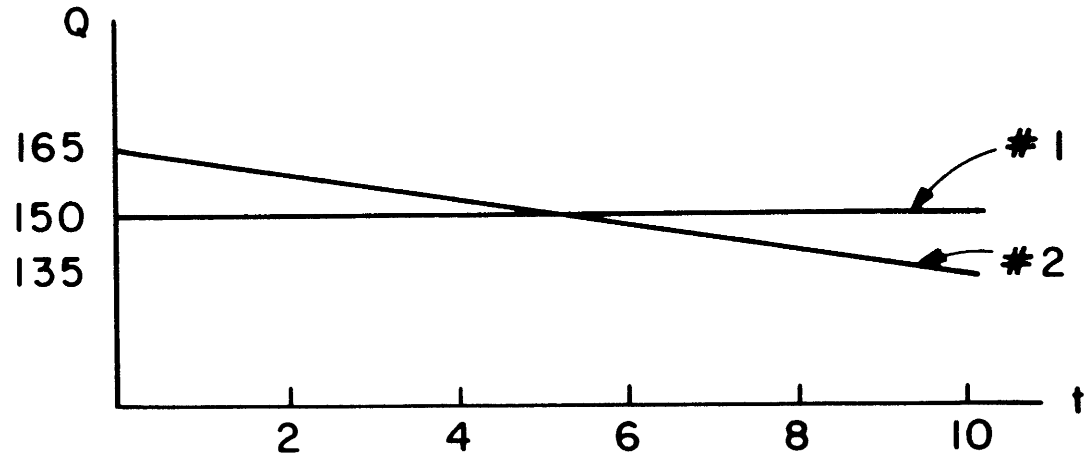
To illustrate this cost to the purchaser, imagine an industrial user of natural gas with capital equipment capable of switching between oil and gas. At the expected price of $3.50 per Mcf of natural gas, this user intends to purchase 150 units of gas. For simplicity, we will begin by supposing that the expected price of oil may be indexed at $3.50 per Mcf equivalent. If the price of oil were to fall in the next year to $2.80, while the consequence fall in the price of natural gas was to $3.00, then a large amount of the user's purchases might be shifted to oil--a net decrease of 70 units of gas purchases. If, on the other hand, the price of oil in equivalent units were to rise to $4.18 in the subsequent years and the price of gas to rise to $4.00, then the net addition to gas purchases might be 52.5 units. This supposed reallocation in purchases across the two commodities represents an optimal adjustment in the face of changing factor costs. A take-or-pay contract in which quantities and prices of take are relatively fixed or constrained will prevent this reallocation of factor inputs. A take-or-pay contract that yielded the producer an expected revenue stream equal to that which would be anticipated in the scenario given above would require the purchase of 150 units of natural gas at a price of \$3.50. This take-or-pay contract would, however, impose upon the purchaser an average increase of 2% in costs above the optimal adjustment case. Alternatively, to assure the purchaser of a long-term contract equivalent to what it would receive in a short-term market, the producer would have to accept a price of \$3.42 per Mcf as opposed to \$3.50

If it were somehow possible to construct a contract in which the purchaser could be given the greater flexibility to adapt its purchases to the conditions it faces, without at the same time yielding to the purchaser the opportunity to use this flexibility to negotiate a price discount or other favorable treatment that would jeapordize the producer's earnings, then this would be a more desirable contract. The "most favored nation" clauses in contracts were for a long time one of the favored devices designed for this purpose. These clauses accomplished the intended purpose when the continual expansion or turnover in the market yielded an acceptable proxy for the short-term prices to which the parties would have agreed, absent opportunism on the part of the purchaser. Lacking similar market conditions, these clauses may no longer be satisfactory in accomplishing this objective. Market-out conditions have been another device most recently popularized for this purpose. It is not clear, however, to what extent they have resolved the contradiction between the need to permit a renegotiation of the price and the need to prevent the purchaser from taking an opportunistic advantage of its *ex post* improved bargaining position.

Price escalators linked to movements in competing fuels are another device that has recently gained greater attention. By linking the price paid to competing fuels, the contract assures purchasers of the return that they could otherwise receive in those circumstances. If the producer is the party most appropriately bearing the pricing risk, the party expected to be making the investments based upon its view of the relative future value of the various fuels, then a commitment tied to the prices of other competing fuels assigns this risk appropriately and therefore minimizes the dead weight loss associated with the use of the take-or-pay contract form. One primary issue regarding price escalators linked to the spot price of competing fuels is the identification of the appropriate fuels for comparison. Commonly the price has been tied to either crude oil prices or fuel oils no. 2 and no. 6. To the extent that these are the marginal competitors for natural gas they may be the appropriate price index commodities. However, as has been commented upon elsewhere in this paper, other fuels will in the future be competitors with natural gas, and therefore other indices may be better used. One advantage of crude oil and heating oil, and perhaps the primary reason why their use has become popular in recent years, is the rise of the organized spot market in these commodities on which a large volume is traded. Hence, although they may not represent the competing fuel in a particular case, the price index tied to the spot on these fuels may be the best available commonly acceptable proxy.

To the extent that any or all of these contract clauses fail to serve as a completely satisfactory proxy for the repeated purchase/sale decisions that would have been made under the various contingencies, there will remain dead weight costs associated with the signing of a long-term take-or-pay contract. One additional opportunity for minimizing this dead weight cost may be identified in the current market conditions in which less than 100% takes are common. A take-or-pay commitment of less than 100% gives to the developer a guaranteed minimal return while also leaving to the producer and purchaser alike a margin of flexibility in its total take and in its pricing terms under the changing market conditions it may face over the years. The same minimal return may be guaranteed by a take-or-pay commitment that begins at 100% but declines over the life of the agreement so the level of total take is identical to what would arise in a constant-take commitment contract. With such a declining-take contract the purchaser's flexibility will be greatest in later years--exactly those years in which the degree of uncertainty is at present the greatest and for which escalator clauses constructed presently will be most at variance with the prices they are intended to proxy.

This discussion can be illustrated with the following figures. Figure 1 depicts the time path of take commitments for a standard contract in which the commitment is constant (#1) and the time path for a front-loaded contract in which the commitment begins at a greater volume but declines at a constant rate (#2). The area under each line represents the total quantity of gas to which a purchaser is committed under each contract. For the two depicted here the total commitment is the same, with the front-loaded contract requiring a larger initial take and a lesser take in the later years of the project. If future relative prices of gas and alternative fuel sources were known with certainty, as well as the future demand for gas in each year, then the two contracts could be written so both the producer and the purchaser would be indifferent between them. If, however, future prices deviate sharply from the anticipated levels, then the front-loaded contract may be preferred by the purchaser and the producer as well. Figure 2 illustrates three possible paths for gas prices relative to a competing fuel source. The critical feature to note is that in later years the price will likely have diverged a great deal from the expected or average level. It may be either above or below, but will likely not be as close as in early years. The take requirements for these later years,



$$\sum_t Q_t(1) = 1500$$

$$\sum_t Q_t(2) = 1500$$

Figure 1

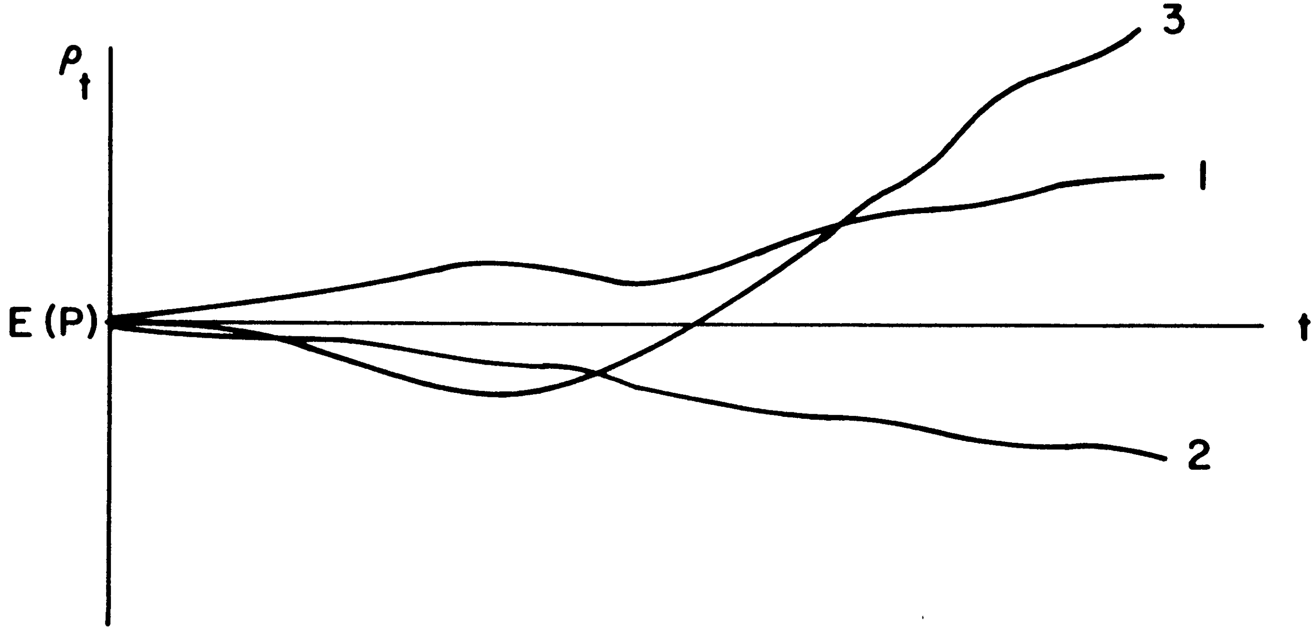
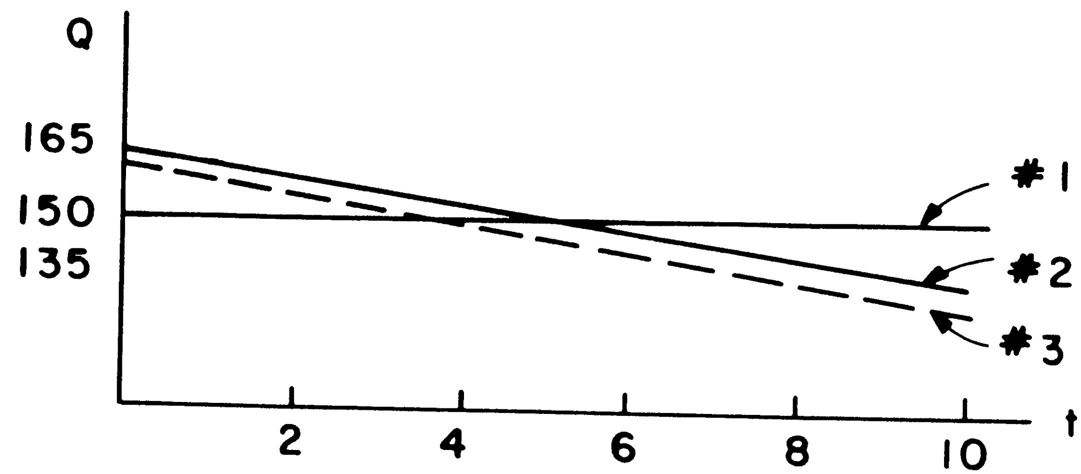


Figure 2

negotiated at an earlier point in time, will likely then include price and quantity requirements that are undesirable to the purchaser relative to the alternative fuels then available. The standard constant-take contract involves a larger take in these later years than does the forward-loaded contract, and therefore is less desirable to the purchaser. The seller, however, does not gain anything by imposing this cost on the purchaser. It is a dead weight loss.

Purchasers negotiating take-or-pay contracts will recognize these costs, and will incorporate the anticipated costs in the average price to which they are willing to commit themselves. If a producer were to offer a front-loaded contract, then he would be in a position to demand a greater average sale price for the gas and the level of total take commitment could be lowered, reducing the dead weight loss from the contracting yet further. This is illustrated in Figure 3. While front-loaded contract #2 involves the identical total take volume, it may be negotiated at a lower price. Alternatively, the total take volume could be decreased, maintaining the feature of front loading, and the negotiated contract could be identical to that which would be agreed upon in the standard contract. This is illustrated in contract #3.

The advantages of forward-loaded take-or-pay contracts are illustrated by the recent history of standard take-or-pay contracts. Faced with the drastic changes in energy prices of recent years, with the recession-induced cutback in demand, and with changes in the border pricing regulation for gas exports from Canada to the United States, many take-or-pay commitments have been renegotiated so lower levels of take will be accepted for a period of time or so various prepayments for gas not taken have been either wavied, deferred, or reduced. In most of these cases the exemption from or amendments to the original commitments are temporary. Nevertheless, they underscore the implied flexibility in the contract in the face of clearly extreme circumstances. The take-or-pay



$$\sum_t Q_t(1) = 1500$$

$$\sum_t Q_t(2) = 1500$$

$$\sum_t Q_t(3) < 1500$$

Figure 3

commitments have, in this case, been de facto front-loaded: Most of the commitment will have been fulfilled in earlier years relative to later years. Anticipating the possibility of a recurrence of such a sequence of events, it would seem to be to the advantage of both parties to give explicit recognition to this possibility by explicitly front loading the contract. This minimizes the likelihood that the parties will be forced into legal or strategic battles over whether or not a particular circumstance warrants amending the commitments to be required.

A small amount of front loading the take-or-pay commitments will increase the flexibility of the purchaser in his own usage decisions without thereby endangering the profitability of the original gas production project. Limits on the length of the make-up period constrain the extent of front loading that would increase the flexibility of the purchaser. In the extreme case of a contract with no greater than a two-year make-up period, if the contract is written with a 100% take commitment in the first three years of the contract, the purchaser will have essentially no flexibility in the face of low demand during the first two years of the contract. The level of take that has been typical in recent contracts appears, however, to have minimized this concern.

Appendix A

EXPLANATION OF THE SIMULATION MODEL

A model is currently under development to simulate the bargaining process facing a producer selling commodities to a small number of potential buyers or a small number of discrete markets. The marketing process is modelled using the structure of an auction as an analog. In the auction model we use, the seller initially sets a high price in the hopes that some buyer will accept that price. If no buyer accepts the price, then it is successively dropped. As soon as enough buyers have accepted a price so capacity is exhausted, the sale is complete. Each buyer would like to wait until the price drops yet further, but is afraid that if it waits too long supply will be completely exhausted. The optimal strategy for a buyer in this type of an auction has been solved, and it is therefore feasible to construct an algorithm with which to calculate the outcome for various parameter values.[4] Moreover, the particular auction that we model has been shown to yield to the seller the highest expected revenue for the sale of its output.

In addition to setting the highest price, the seller establishes a floor price for the auction below which the seller will not drop the price. This floor price is critical because it affects the buyer's anticipation that by waiting he may receive a lower price: The higher the floor price, the higher is

[4]See Milton Harris and Artur Raviv, 1981, "Allocation Mechanism and the Design of Auctions," Econometrica, 49:1477-1499, and Milton Harris and Artur Raviv, "A Theory of Monopoly Selling Schemes with Demand Uncertainty," American Economic Review, 71:347-365.

the point at which a given buyer signals his willingness to pay the going price. The level of the floor price is determined primarily by the marginal cost of producing a unit: This is because it is the marginal cost of production that determines the strength of the seller's negotiating position in the face of excess capacity and buyers hoping to purchase output at sale prices. The seller will never accept a price below the marginal cost of production. In most cases there will be several buyers willing to pay a price above the marginal cost and the seller will not need to impose this condition. In a few cases, however, there will be only a few buyers willing to pay the marginal cost or slightly greater. In these cases the seller will produce only enough to satisfy these buyers, and at prices in the range of the marginal cost. The importance of this lower bound is determined by the frequency of these cases.

This lower bound is the critical feature for our analysis of the value to commitment in a long-term contract. When long-term contracts are signed before a field is completely developed and the capital costs expended, the marginal cost that determines the floor price below which the seller will not drop is inclusive of marginal capital costs. If long-term contracts have not been signed, then the relevant marginal costs will be the operating and transportation costs alone or supplemented with those capital costs that are truly marginal. We will run a model of the auction using marginal costs inclusive of marginal capital expenditures, and using marginal costs exclusive of capital expenditures. The expected revenues from each auction will be compared. The difference between these expected revenues represents the financial value to the producer of obtaining the long-term purchase commitment.

This research will be completed and documented at a later stage of the Natural Gas Project.

A NORTH AMERICAN NATURAL GAS TRADE MODEL: PART I

by

Charles R. Blitzer

A NORTH AMERICAN NATURAL GAS TRADE MODEL: PART II

by

Arthur W. Wright

A NORTH AMERICAN NATURAL GAS TRADE MODEL: PART I

by

Charles R. Blitzer

A NORTH AMERICAN NATURAL GAS TRADE MODEL:

PART I

by

Charles R. Blitzer

INTRODUCTION

This is a brief description and overview of the North American natural gas trade model, which has been developed as part of the CEPR project on international gas issues. The primary purpose of the model is to provide a consistent framework for estimating the costs and benefits to Canada and Canadian firms of alternative gas production and export programs. Each time the model is run, it calculates profit-maximizing time profiles of production and exports, given a set of specific assumptions about investment and operating costs, deliveries to the Canadian market, the shape of demand functions in different export markets, and relevant governmental regulatory policies.

The logic of the model can be stated succinctly. The model starts with a set of constraints. Some of these are technical, such as those relating production profiles to reserves and installed capacity. Others represent policy interventions such as taxes and royalties or non-technical limits on production. There are also economic constraints, such as those relating the level of exports in each year to sales revenue in each market in the United States and projections of discount rates and operating and investment costs. The levels of demand use in Canada is an exogenous projection, and the implicit assumption is that changes in gas export policy will not have substantial feedbacks on the Canadian macroeconomy or internal fuel substitution. This is a simplification assumption, which is made in order to focus on the gas trade issues. There are also accounting constraints to insure that deliveries do not exceed production and to keep track of investment requirements, operating costs, production capacity, and so forth.

Collectively, the constraints impose limits on what can be produced and exported within a period of time. That is, they define a set of internally consistent alternative possibilities regarding gas production (from which field or pool), and gas exports in each year (to which market and through which pipeline). The problem the model is asked to solve is to rank these alternatives and to determine the most profitable alternative from the feasible set. This ranking is done by taking into account estimated operating and capital costs for each reserve pool, price-sensitive demand functions for Canadian gas exports, and risk-adjusted discount rates.

The ranking is done on the basis of profit maximization, where profit maximization can be defined in several ways. For instance, the model can be solved assuming that Canada recognizes that it faces a downward sloping demand function for its exports to the United States and pursues a restrictive policy aimed at exporting up to the point at which marginal export revenue equals marginal costs. The implementation of such a policy implies either explicit governmental regulation of prices or quantities, or collusive behavior among the producers. Alternatively, the model can assume that each producer, representing a small part of the market, acts as if the level of his sales does not affect the price of other sales. In this case, gas exports are made up to the point at which the price to the producer (net of royalties) equals marginal costs. Finally, for reference purposes, the model can calculate the globally efficient solution that maximizes the joint benefits to both the

United States and Canada, rather than to just Canada.[1] These behavioral rules are explained more fully later in this chapter in the sub-section on objective functions.

Gas production, investment levels, and gas exports are calculated at three-year intervals beginning in 1985 and continuing until 2015. This long time horizon is required to account fully for the long investment lags and long operating lives of major capacity expansion projects. Dynamic relations are also important because production in earlier periods affects marginal production costs in the future. Because of well-known and inevitable problems with terminal conditions, we report results only through 2006.

As now formulated, the model includes nine different potential "pools" of reserves. Seven are in Western Canada and two are in the East. Pools differ in their total size (measured in TCF) and their capital and operating costs. There are three separate gas markets in the United States: West Coast, Middle West, and North East. Western Canada can export gas to each of these regions, but Eastern Canada's exports can go only to the Northeast.

The remainder of the paper is divided into three sections. In the next section, the algebraic formulation of the model is presented and discussed. The internal pricing structure of the model is reviewed in the following section. Finally, we close with a brief description of the results from an actual run of the model comparing how the solution differs depending on which of the three behavioral variants is used.

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[1] In the first version, the model maximizes Canadian profits, that is, discounted gross export revenues less capital and operating costs. The maximand for the third version, "perfect competition," is discounted consumer surplus in the United States associated with gas imports from Canada less capital and operating costs. Royalties are an additional cost item for the second version.

MODEL FORMULATION

In technical terms, the model is formulated as a mathematical programming problem in which a computer algorithm is used to find the optimal time path of the values of the endogenous variables (e.g., exports to each United States market and investment and production in each gas pool).[2] As part of the solution procedure, dual variables are calculated. These include marginal costs of production, export prices, marginal export revenues, capital rental charges, resource depletion costs, etc. The formulation and methodology is similar to the industrial sectoral planning models that have been used by economists and operations researchers for many years. What is new in the model is the specific application and the data, not the methodology.[3]

We report on the present formulation of the model. It should be understood that this modelling framework is considerably more flexible in the sense that additional constraints, project, activities, policy interventions, etc. could be added. Indeed, as the model is used, it will be important to make modifications based on initial results and enhanced perceptions of the issues that need further investigation.

---

[2] The particular version reported here is formulated as a linear programming problem using piece-wise linearizations of downward sloping demand functions. This is done primarily to save on computer costs. Introducing explicitly non-linear functions for costs and export demand would not raise any conceptual problems. Similarly, excellent algorithms exist for handling non-convexities, such as for pipeline investment costs that exhibit significant scale economies.

[3] Other models of the Canadian gas industry and exports have been developed at the University of Alberta and the Alberta Research Council. In comparison to these, our model is innovative in its explicit treatment of downward sloping demand functions and its ability to simulate different kinds of economic behavior.

The model is described more detail in the following sub-sections. The format in each section will be to provide the underlying motivation of the constraint and describe it specifically in words and algebraic equations. In general, endogenous variables are represented by capital letters and parameters by lower case letters. Bars over letters indicate exogenous variables. The subscripts "i", "p", "j", and "t" refer to Canadian regions, reserve pools, export markets, and the time period, respectively.[4] All quantities are in BCF units.

Supply-Demand Balances

We begin with the requirement that total gas production in each Canadian region must be sufficient to meet that region's deliveries to Canada and each export market. These supply-demand balances are expressed in the following relationship:

Total Production, Region i	$\geq$	Canadian Deliveries, from Region i	+	Total Exports, from Region i

$X_{i,p,t}$ represents annual production from reserve pool p (if it is located in region i) in year t; $D_{i,t}$ represents the exogenously projected deliveries to Canada; and $E_{i,j,t}$ stands for total gas exports from region i to market j in period t.[5] All units are measured in BCF per year. Algebraically, we have:

$$(1) \qquad \sum_p X_{i,p,t} \geq \overline{D}_{i,t} + \sum_j E_{i,j,t}$$

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4 Recall that there are two Canadian regions (West and East) and three United States export markets (West Coast, Middle West, and North East). The nine pools are characterized by location, reserve base, and operating and investment cost structure.

5 In the numerical applications, it is assumed that all Canadian demand is provided by the Western Canada region.

Production-Reserve Relationships

There is a recursive relation between production in any one period and remaining reserves in the next period. That is:

$$\begin{matrix}\text{Reserves in Pool}\\ \text{p, at Start of}\\ \text{Period t}\end{matrix} = \begin{matrix}\text{Reserves in Pool}\\ \text{p, at Start of}\\ \text{Period t-1}\end{matrix} - \begin{pmatrix}\text{Number}\\ \text{of Years}\\ \text{per Period}\end{pmatrix} \bullet \begin{pmatrix}\text{Annual}\\ \text{Production}\\ \text{of Pool p,}\\ \text{Period t-1}\end{pmatrix}$$

Defining $R_{p,t}$ and reserves of pool p at the start of period t and remembering that periods are three years in length, the equation form is:

$$(2) \qquad R_{p,t} = R_{p,t-1} - 3\, X_{i,p,t}$$

The following constraints represent a simple approximation to the limitations on annual production imposed by the level of remaining reserves. That is, production in each pool can be no greater than an exogenously specified fraction of reserves left in that pool.[6]

$$\begin{matrix}\text{Annual}\\ \text{Production}\\ \text{of Pool p,}\\ \text{Period t-1}\end{matrix} \leq \begin{pmatrix}\text{Maximal Rate of}\\ \text{Reserve Depletion}\\ \text{of Pool p,}\\ \text{Period t}\end{pmatrix} \bullet \begin{pmatrix}\text{Reserves in Pool}\\ \text{p, at Start of}\\ \text{Period t}\end{pmatrix}$$

These maximal rates, $a_{p,t}$, can represent technical/engineering limits or more restrictive policy interventions. Initially, technically imposed bounds are assumed.

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[6] We recognize that the technical relationship between production and reserves is more complicated, but have adopted this formulation for its simplicity. If data were available, it would not be difficult to substitute more complex equations.

(3) $$X_{i,p,t} \leq a_{p,t} R_{p,t}$$

Similarly, there are constraints that insure that total production within the horizon does not exceed some fraction of reserves. This amounts to imposing lower bounds on the reserves of each pool that must be left in the ground at the end of the model's planning period. The fractions, b_p, represent policy variables and can be altered for each exogenous scenario. Again, the model itself could incorporate more complex relationships. For instance, these types of constraints could be designed specifically to simulate and evaluate the effects of 25-year production-reserve restrictions or explicit postponement of projects that would otherwise be economic to undertake in earlier years.

$$\begin{matrix}\text{Total Production}\\ \text{from Pool p,}\\ \text{1985-2015}\end{matrix} \leq \begin{pmatrix}\text{Maximum}\\ \text{Reserve Depletion}\\ \text{Pool p}\end{pmatrix} \bullet \begin{pmatrix}\text{Initial}\\ \text{Reserves}\\ \text{Pool p}\end{pmatrix}$$

or

(4) $$\sum_t X_{i,p,t} \leq b_p \overline{R}_{p,o}$$

Production-Investment Relationships

Annual production in each pool is also constrained by available productive capacity, which in turn depends on previously undertaken investment projects and whatever remains of the capacity that exists in 1985 (before the model starts making its own investment decisions). The latter is exogenous to the model, while capacity expansion after 1985 is determined endogenously on the basis of profit maximization. That is:

Annual Production of Pool p, Period t	$\leq$	Capacity Remaining from 1985, Pool p	+	Capacity Created after 1985, in Pool p

$Y_{p,t}$ stands for capacity (in BCF per year) to produce from pool p which first becomes available in year t. This capacity lasts q_i periods, after which it is lost.[7] $K_{p,o}$ is the 1985 capacity and d_i is the rate of depreciation. With three years between time periods, we have:

(5) $$X_{i,p,t} \leq \overline{K}_{p,o}(1-d_i)^{3t} + 3\sum_n Y_{p,n}$$

where the index "n" runs from year t back to year $t-q_i$.

Export Delivery Patterns and Pipeline Constraints

Exports of gas from each region i (West and East) to each market j (West Coast, Middle West, North East) may be limited by existing pipeline capacity, as well as by the pipeline charges that exporters must pay. The model takes pipeline capacity as exogenous projections and does not include investment in expansion of this capacity as something to chose endogenously.[8]

Exports from Region i to Market j, Period t	$\leq$	Capacity of Pipeline from Region i to Market j, Period t

Defining capacity as $P_{i,j,t}$, the constraint is:

[7] For example, if capital lasts 15 years, q would have the value 5.

[8] The economics of pipeline expansion can be estimated either by parametric change or by including alternative investments as endogenous variables. Because of economies of scale in pipeline costs, the latter approach implies using some sort of non-convex programming algorithm. Therefore, pipeline investment is not included in the initial version. If the solutions indicate that more pipeline capacity is needed, a minor alteration of model (but one which could involve more computational cost) could be made.

(6) $$E_{i,j,t} \leq \overline{P}_{i,j,t}$$

Total sales (in BCF) of gas to market j are the sum of exports to that market from the two regions, i. At present the distinction between sources is relevant only for sales to the North East.

Exports to Market j, Period t	=	Exports from Western Canada to Market j, Period t	+	Exports from Eastern Canada to Market j, Period t

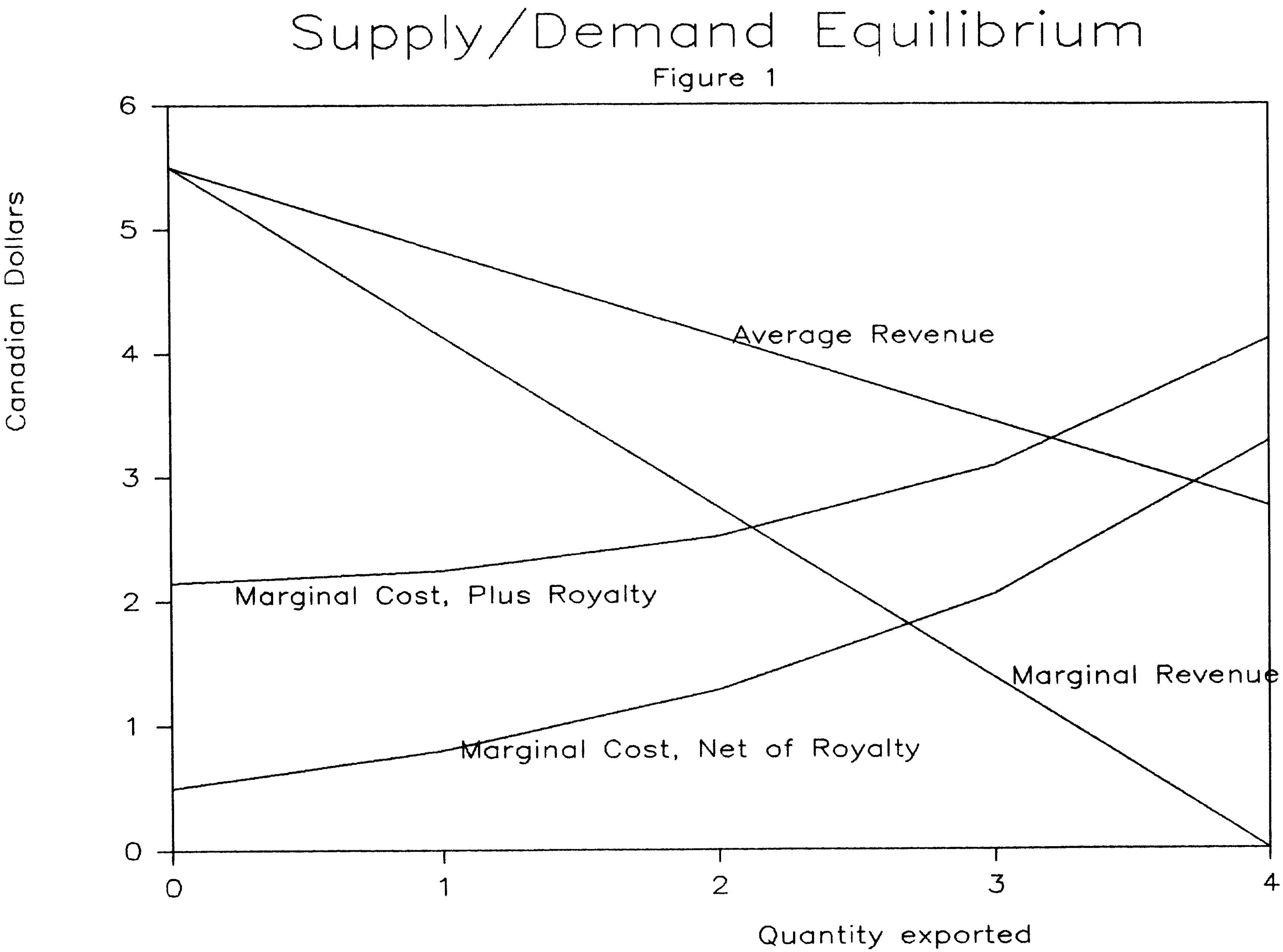
or, defining exports to market j in year t as $EX_{j,t}$,

(7) $$EX_{j,t} = \sum_{i} E_{i,j,t}$$

Export Revenue

Other than the limitations imposed by the pipeline constraints, exports can vary widely and are constrained only by costs and revenues. The revenue associated with any level of exports to a market are calculated using price-sensitive demand functions for each of these markets. Thus, greater exports in any year to any particular United States market may or may not yield greater total revenue depending on the slope of the demand function for that region.

To clarify this concept, refer to Figure 1. Here, the average revenue curve represents total revenue divided by the quantity sold, or the average price. This is normally referred to as the "demand" function. The downward


Supply/Demand Equilibrium
Figure 1
Canadian Dollars
Average Revenue
Marginal Cost, Plus Royalty
Marginal Revenue
Marginal Cost, Net of Royalty
Quantity exported
0
1
2
3
4
5
6

sloping curve beneath this is the marginal revenue function. It measures the increase in total revenue from a marginal increase in export volume. The reason that marginal revenue is less than the price or average revenue is that average revenue falls as quantities exported are increased.[9]

While downward sloping demand functions could be handled by available non-linear programming methods, the present version of the model uses demand functions that are piece-wise linear. That is, within a given range or segment, the slope of the demand function (and the marginal revenue function) is constant.[10] The only restriction on how complex the demand functions can be is that they do not create a non-convex problem that would produce perverse results when economic maximization rules are applied. Among the demand functions which could be tested, are those that simulate the dynamics of market penetration, which one year's demand function is determined in part by the level of sales in earlier years. The only problems with more complex formulations are greater computational costs and increased difficulties in parameter estimation.

The total quantity of gas exports to market j in any year is then simply the sum of the amounts exported in each linear segment of the demand functions. Clearly the most that can be exported in any one segment is the difference between the given amounts associated with the two end points of that segment. The model will always export first along the first segment, by

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9 In the simple case of a linear demand function, which is shown in Figure 1, the slope of the marginal revenue function is always twice (in absolute terms) that of of the demand function itself.

10 Specifically, the model is given the average price at a set of different quantities exported. The marginal revenue for volumes between any two consecutive points is the ratio of the difference in total revenue between the given points (price times quantity) to the difference in volumes between those points.

construction the one with highest marginal revenue. Then it will utilize the second segment, and so forth. In word equation form:

Exports to Market j, Period t	=	Sum of Exports to Market j, in Segment g, Period t

Algebraically, define $\Delta_{j,g,t}$ as exports to market j in year t, along linear demand segment g. For each market there are 6-10 such segments. In each segment, $\Delta_{j,g,t}$ has an upper bound that is determined by the specific points of the demand function for that market in that year. That is:

(8) $$EX_{j,t} = \sum_{g} \Delta_{j,g,t}$$

(9) $$\Delta_{j,g,t} \leq \bar{\Delta}_{j,g,t}$$

Revenue from sales to each market are the sum of revenues from exports along each segment.

Export Revenue from Market j, in Period t	=	Sum of Exports Revenue in Market j, Segment g, Period t

Total export revenue of sales to the j'th market in period t are represented by $REV_{j,t}$, and the revenue of exports in the g'th segment are $REV_{j,g,t}$. Define $c_{j,g,t}$ as the constant marginal revenue associated with exports in segment g. We then have the following relationships:

(10) $$REV_{j,g,t} = c_{j,g,t} \Delta_{j,g,t}$$

$$\text{REV}_{j,t} = \sum_{g} \text{REV } j,g,t \tag{11}$$

The segments are labeled consecutively, starting with lowest level of sales (and highest prices), then increasing up until the point of maximum sales and lowest average price. There may be few or many segments. The only restrictions on the piece-wise demand functions are that they must not have marginal revenue increasing as greater amounts of gas are exported in any one year to any one market. Otherwise the programming problem would no longer convex and well-defined.

Consumer Surplus Calculations

While only export revenue as a function of export quantities is required to solve the model when Canadian profits are the objective, finding the "competitive" solutions (with or without royalties, as will be discussed in the following sub-section) involves calculating the value to United States purchasers of imports from Canada. The value, usually referred to as consumer surplus, can be approximated as the area under the demand curves for each level of exports in each market, less payments made to Canada for those sales.

For example, take any point on the average revenue or demand curve in Figure 1. Consumer surplus at that quantity is then approximated by the area of the the triangle defined by that point itself, the intercept of the demand function with the vertical axis, and the intercept of a horizontal line drawn from the vertical axis to the given point on the demand curve. Here, a point on the average price or demand curve, has the interpretation of the marginal utility of gas imports at that point.

Since, the model utilizes segmented horizontal average price functions, each of these segments has a specific consumer surplus associated with it. Therefore, total consumer surplus is the sum of the consumer surplus associated with exports along each of the segments.

$$\begin{array}{c}\text{Consumer Surplus}\\\text{in Market j,}\\\text{in Period t}\end{array} = \begin{array}{l}\text{Sum of Consumer}\\\text{Surplus in Market j,}\\\text{Segment g, Period t}\end{array}$$

$CS_{j,g,t}$ and $CX_{j,t}$ stand for consumer surplus in the g'th segment and the total for market j in year t. As with export revenue, consumer surplus in each segment is a linear function of the Δ for that segment, with marginal consumer surplus given the the coefficient $f_{j,g,t}$.[11]

(12) $$CS_{j,g,t} = f_{j,g,t} \; \Delta_{j,g,t}$$

(13) $$CS_{j,t} = \sum_{g} CS_{j,g,t}$$

<u>Cost Calculations</u>

The model considers three types of out-of-pocket costs. These are the operating (or current) costs of production and pipeline usage, and capital costs associated with investment and capacity expansion. The unit costs of each of these are projected exogenously. First consider operating costs.

$$\begin{array}{c}\text{Operating}\\\text{Costs,}\\\text{Pool p,}\\\text{Period t}\end{array} = \left(\begin{array}{c}\text{Unit}\\\text{Operating}\\\text{Costs,}\\\text{Pool p}\end{array}\right) \bullet \left(\begin{array}{c}\text{Annual}\\\text{Production}\\\text{Pool p,}\\\text{Period t}\end{array}\right)$$

---

[11] In any one segment, this coefficient is taken as the average of the prices associated with the beginning and end points of that segment.

Letting OC_t represent total operating costs in year t and oc_p unit operating costs of production from reserve pool p, this is equivalent to:

(14) $$OC_t = \sum_p oc_p X_{i,p,t}$$

Similarly, pipeline operating costs (POC_t) are determined as linear functions of exports from source i to market j. That is:

$$\begin{matrix}\text{Operating} \\ \text{Costs,} \\ \text{Pipeline} \\ \text{(i,j), in} \\ \text{Period t}\end{matrix} = \begin{pmatrix}\text{Unit} \\ \text{Operating} \\ \text{Costs,} \\ \text{Pipeline} \\ \text{(i,j)}\end{pmatrix} \bullet \begin{pmatrix}\text{Exports from} \\ \text{Region i to} \\ \text{Market j,} \\ \text{Period t}\end{pmatrix}$$

(15) $$POC_t = \sum_p poc_p E_{i,j,t}$$

Annual capital costs are more complicated to calculate because of the gestation lags between when expenditures on new capacity are first incurred and when that capacity is first available. For each reserve pool, the model has a specified time structure of capital expenditures. For example, for pool "2" the model might need to make capital outlays in two periods prior to when the capacity is available, as well as in the year it comes on stream. In any given year then, the total capital outlay is the sum of outlays on all capacity additions in the "pipeline." The relationship specified is:

$$\begin{matrix}\text{Capital} \\ \text{Outlays for} \\ \text{Pool p,} \\ \text{Period t}\end{matrix} = \begin{pmatrix}\text{Capital cost} \\ \text{Structure of} \\ \text{Pool p}\end{pmatrix} \bullet \begin{pmatrix}\text{Capacity Addition} \\ \text{of Pool p, Coming} \\ \text{On-line in Future}\end{pmatrix}$$

Specifically, let v_p stand for the number of periods before an investment comes on line that investment expenses are incurred. Total investment expenses associated with capacity expansion in reserve pool p in year t (defined as $IN_{p,t}$) then depend on the level of capacity which comes on line in year t ($Y_{p,t}$), as well expansions that will be available in period t+1 to $t+v_p$. The parameters $s_{p,g}$ are the costs incurred "g" periods before an investment comes on stream per unit of capacity expansion in pool "p." In the following equation, the index g goes from zero (costs incurred in period an investment actually becomes operational) to v_p.

$$IN_{p,t} = \sum_g s_{p,g} Y_{p,t+g} \tag{16}$$

Objective Function

The objective function represents what the model is attempting to maximize. As noted in the introduction to this chapter, the model is solved using three different behavioral rules:

--Maximize net benefits to Canada as a whole (Version 1);

--Maximize the sum of net benefits to Canada and United States importers of Canadian gas (Version 2); and

--Simulate competitive profit maximizing behavior among Canadian producers inclusive of royalties (Version 3).

In this sub-section, we describe the specific objective functions that correspond to each of these outcomes. Figure 1 is used to illustrate the underlying interpretation of each type of solution and how the model arrives at each of them. Here, we simplify by focussing only on one export market and one time period. However, these simplifications do not alter the behavioral character of the model in the more complicated case of many markets and many time periods.

There are four curves shown in Figure 1, two relating to export demand and two to supply and marginal costs of production. As mentioned in the subsection on export demand, the average revenue or demand curve represents the relation between quantities exports and the price paid. The total revenue associated with any level is exports is merely that quantity times the average price. The marginal revenue function measures how much total revenue changes when larger amounts are exported.

The upward sloping curves are a representation of marginal costs. The lower of the two includes only true economic costs, or what might be called "real" costs. These include direct costs such as investment and operating expenditures, and indirect or "user costs" which relate to resource depletion.[12] Here, all taxes and royalties are ignored. The other marginal cost curve lies above the first, because it adds taxes and royalties to the costs faced by producers. For simplicity, the tax or royalty rate used in drawing this curve is taken as a constant fraction of average sales price.[13]

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[12] What this means is that if low-cost reserves are used up more rapidly, future production will be more costly since greater reliance on high-cost resources will be necessary. In other words, the position of the marginal cost curve in any year is determined in part by production decisions made previously.

[13] This does not imply that there are no royalties on production destined for local markets. The royalty rate imposed on production for domestic consumption is assumed fixed in the model, just as total domestic demand is, and is unaffected by export volumes. The endogenously determined royalty payments are those that relate to netback on exports. On the other hand, the model could include (in addition or instead) a fixed royalty, measured in \$/Mcf, for all production.

The different intersections of these curves represent the different versions of the model. For Version 1, the objective function represents net profits to Canada of the model's choice of production and export levels and patterns. It includes export revenue as a positive item, and operating and investment costs as negative items. In terms of Figure 1, this outcome corresponds to the intersection of the marginal revenue function with the net-of-royalty marginal cost curve.[14] In the model itself, exports and costs are calculated for each period, then discounted using risk-adjusted discount rates which may vary according to what category of cash flow is being considered.[15] The objective function for Version 1 then is:

Discounted Profits to Canada	=	Discounted Export Revenues	-	Discounted Operating Costs	-	Discounted Pipeline Costs	-	Discounted Investment Costs

Algebraically, we define $\delta_{e,t}$, $\delta_{o,t}$, and $\delta_{in,t}$ as the discount factor associated with flows of export revenue, operating costs, and capital costs respectively in period t.

$$(17)\quad \text{Maximand 1} = \sum_t \left(\delta_{e,t} \sum_j REV_{j,t} - \delta_{o,t}\,(OC_t + POC_t) - \delta_{in,t} \sum_p IN_{p,t}\right)$$

Version 2 of the model seeks to calculate the globally efficient (or perfectly competitive) solution, the one which maximizes the sum of net

[14] Dropping a line from the intersection of these curves to the horizontal axis defines the optimal level of exports. The export price is determined by drawing a line up from this intersection to the average price curve. It is not difficult to prove geometrically that this is the point of maximum profit for the exporters.

[15] The objective function may also include valuation terms for production capacity and pool reserves which remain after the model's terminal date. These have not yet been implemented. Terminal year distortions have been reduced by extending the time horizon several time periods past the last year we are interested in examining, 2006.

benefits to Canada (discounted total export revenue, less discounted direct costs) and net benefits to United States purchasers of Canadian gas (discounted consumer surplus, represented by the area under the demand curve less the purchase cost of the gas). In Figure 1, this outcome corresponds to the intersection of the demand curve with the net-of-royalty marginal cost curve. This is the globally efficient solution because, in principle, the loser from moving to this point from any other can be compensated by the gainer leaving both better off.[16] This maximand is:

$$\begin{array}{c} \text{Total Benefits} \\ \text{to United States} \\ \text{and Canada} \end{array} = \begin{array}{c} \text{Discounted} \\ \text{Consumer} \\ \text{Surplus} \end{array} + \begin{array}{c} \text{Discounted} \\ \text{Canadian} \\ \text{Profits} \end{array}$$

Discounted Canadian profits are defined in equation (17) and United States consumer surplus in equation (13). Combining them, we have:

$$(18) \qquad \text{Maximand } 2 = \sum_t \delta_{e,t} \sum_j (CS_{j,t} + REV_{j,t}) - \delta_{o,t} (OC_t + POC_t)$$

$$- \delta_{in,t} \sum_p IN_{p,t})$$

The objective function for Version 3 is similar to that for Version 2 in the sense that buyers and sellers act competitively without collusion. The difference here is that the producers in maximizing their own individual profits also react to royalties imposed by Canadian governments. This version represents the result of private profit maximization by the firms in the

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[16] This is the standard definition of Pareto efficiency, but in the real world achieving such cooperative solutions typically is very difficult. At the same time, if the potential gains are substantial, this version points to the advantages which both countries could achieve by negotiating some scheme to share the benefits of more competitive behavior. Note also that exports are always greater than in Version 1.

industry acting competitively against each other. Note that this is not the same as monopolistic behavior by the industry facing royalties, but acting collusively.

In this version, the marginal cost curve includes the royalties and, therefore, lies above the net-of-royalty curve shown in Figure 1. The solution in this case is represented by the intersection of this marginal cost curve with the demand function. Technically, this corresponds to finding the solution which maximizes the sum of area under the demand curve plus the area above the royalty-inclusive marginal cost curve.[17] That is:

$$\text{Maximand} = \begin{array}{c}\text{Discounted}\\ \text{Consumer}\\ \text{Surplus}\end{array} + \begin{array}{c}\text{Discounted}\\ \text{Private}\\ \text{Canadian}\\ \text{Profits}\end{array}$$

The algebraic formulation is the same as in equation (18), except that royalties are now subtracted. The royalty rates apply to production that is exported (for reasons discussed above), are taken as fixed in each export demand segment, and are defined as $tax_{j,,g,t}$. Total royalty payments derived from sales to market j in year t are referred to as $TAX_{j,t}$. The equations defining these royalty payments and the objective function for Version 3 are:

(19) $$TAX_{j,t} = \sum_g tax_{j,g,t}\ \Delta_{j,g,t}$$

(20) $$\text{Maximand } 3 = \sum_t (\delta_{e,t} \sum_j (CS_{j,t} + REV_{j,t} - TAX_{j,t})$$

$$- \delta_{o,t}\ (OC_t + POC_t) - \delta_{in,t}\ \sum_p IN_{p,t})$$

[17] If private producers were to act collusively or monopolistically, they would attempt to equate marginal revenue with the royalty-inclusive marginal cost. As shown in Figure 1, this would imply export volumes less than in the competitive case or the other versions that are modelled. Although the model can simulate this behavior, we have not attempted this in the numerical experimentation conducted to date.

Note that export volumes here will always be lower than in the perfectly competitive case (Version 2). Depending on the chosen royalty rates, export volumes may be greater than (as shown in Figure 1) or less than for Version 1. This implies that if these were chosen optimally, this behavioral rule would also lead to maximized total profits to Canada. Comparing the Version 1 results with those implied by Version 3 provides a mechanism to test the optimality of a set of royalty rates. Indeed, one of the attractive features of the model is this ability to provide a measure of the net costs and benefits of government intervention.

PRICE STRUCTURE OF THE MODEL

The behavior of the model has been illustrated using the demand and marginal cost curves shown in Figure 1. As explained in the previous section, the demand curves and marginal revenue curves are given directly to the model in the form of piece-wise linear segments. However, the model is not given marginal cost curves in any direct way. Rather it is given the direct costs of certain activities (production and investment) and a number of additional constraints that limit how much can be produced in specific pools or exported through pipelines, etc. The model itself puts this information together to determine endogenously the shape of the marginal cost curves and how they shift depending on the production, investment, and export decisions that the model makes. The calculation of marginal costs is always done on the basis of cost minimization, taking into account both direct and indirect production costs.

In addition to solving for each of the endogenous variables referred to previously (technically called primal variables), the programming algorithm also calculates a set of implicit or "shadow" prices (dual variables). Each constraint or equation has a shadow price associated with it which represents the marginal cost, in terms of whatever objective function is being used, of that constraint. These are calculated based on the model's internal cost structure and are used in determining the optimality of any intermediate solution. In effect, the model knows that an optimal solution is found when: (a) all variables which are positive in the solution have the property that the marginal benefits (MB) from increasing that variable by a little bit exactly equal the marginal costs (MC) of doing so, and (b) there are no variables for which marginal benefits exceed marginal costs.[18] These costs and benefits are calculated using the shadow price structure. The shadow prices also have the useful property that they can be used in evaluating specific projects outside the model itself, so long as those projects are not too large relative the the gas sector as a whole.

Rather than going through the complete shadow price structure of the model, here we illustrate how it works by examining the interrelations among a few key prices and variables.

Consider first the costs and benefits of producing from a certain pool p in region i in year t, the variable $X_{i,p,t}$. We see from the previous section that this variable appears in six constraints: (1), (2), (3), (4), (5), and (14). The shadow prices associated with each of these equations or constraints can be used to perform a cost-benefit test on whether this variable should be increased or decreased. The rule for an optimal solution

[18] These are known as the complementary slackness conditions and hold for all optimizing problems.

with $X_{i,p,t}$ positive is that MC=MB. If MB>MC, then it would make sense to increase $X_{i,p,t}$, and the reverse if MB<MC.

The marginal benefits of one more unit of gas from pool p is merely the shadow price of constraint (1). This is the supply/demand balance equation, which can be thought of as a market for gas. Each producer in a region sells gas for the same price, either for domestic use or to exporters resale at the border after pipeline costs have been added.

One element of marginal cost is operating costs. These are calculated as the operating costs in nominal dollars, $oc_{i,p}$, times the shadow price of the operating cost equation (14). This shadow price takes account of whatever discounting is appropriate for operating costs in year t. Another element is the implicit annualized costs of using the capital equipment required for production. This is the shadow price associated with constraint (5).[19]

In addition to these, there are "user" costs related to resource depletion. These appear as the shadow prices of constraints (2), (3), and (4). The shadow price of (3) is the value of being able to produce one more unit from a low cost pool in which production is constrained by an upper limit related to remaining reserves. The shadow price of (2) represents the cost of limiting future production from the pool because depletion now decreases the upper bounds on possible production in later years.[20] Finally, the shadow price of constraint (4) stands for the cost of maximal depletion over the entire planning horizon, a factor which may or may not be determined by policy.

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[19] This cost is neither depreciation in the accounting sense nor the investment payments made to increase capacity. Rather, it is a charge that the model itself determines based on investment costs, gestation lags, life of capital, and the discount rate.

[20] In the marginal cost-benefit test, this shadow price is multiplied by three to represent the fact that the model calculated annual averages for a three-year period.

Note that if any constraints are not binding, as is frequently the case with constraints (2), (3), and (4) for high-cost pools, the shadow prices of those constraints of course are zero.

As a second example, consider the costs and benefits of an investment activity to expand capacity in pool p that first comes on stream in year t, $Y_{p,t}$. The costs of this activity appear in equation (16). Actually, they may appear more than once because some of the investment cost is incurred in year t, some in year t-1, and perhaps some in earlier years as well. The total cost of the capacity expansion then is the sum of the shadow prices of equation (16) in each of the years when there is an out-of-pocket investment charge times the "s" parameter associated with that many years before the investment project is completed.

The benefits of the investment are the discounted sum of the capital rental charges that accrue in year t and in the years following until the investment physically depreciates. These are the sum of the shadow prices associated with constraints (5) for each of these years. They are each multiplied by the factor "3" because the model does three-year averaging.[21]

As a final example, consider the price structure associated with gas exports. There are three types of export variables, $E_{i,j,t}$, $EX_{j,t}$, and $\Delta_{j,g,t}$. The $E_{i,j,t}$ variables appear in equations (1), (6), (7), and (15). On the cost side, gas is purchased in market i at the shadow price of constraint (1), and to this is added pipeline operating charges (the "pop" coefficients times the shadow price of equation (15) which discounts this

[21] Conceptually, the model also should account for the future stream of rentals after the horizon date for capital stock which is not then fully depreciated. To overcome this problem, we have extended the horizon date significantly. In future versions, this will also be accounted for more directly using adjustments to the cost of capital stock, which will continue to be useful post-terminally.

cost) and a pipeline capacity charge (the shadow price of constraint (7)) if the pipeline from i to j is fully utilized in time t. Then the gas is sold at his combined price, which also equals the shadow price of equation (7).

The $EX_{j,t}$ activities "buy" gas at this price and "sell" at the shadow price of equation (8). This marginal value of sales is found by looking at the marginal export segment, $\Delta_{j,g,t}$, the last one which is used in a particular solution. The marginal cost of increasing $\Delta_{j,g,t}$ is the sum of the shadow price of equation (8) and the shadow price of constraint (9), the upper bound on that export segment.[22] The benefits (which of course feed back on all the other shadow prices) depend on which version of the model is being solved. For Version 1, the benefits are marginal export revenue, $c_{j,g,t}$, discounted by the factor $\delta_{e,t}$. For Version 2, the benefits are augmented by adding the consumer surplus factor $f_{j,g,t}$ before discounting. For Version 3, the marginal benefits are $c_{j,g,t}+f_{j,g,t}+tax_{j,g,t}$.

In a similar way, the full price structure of the model can be readily analyzed. For example, the marginal value of finding additional reserves for any particular pool with given costs can be determined using the shadow prices of equations (2), (3), and (4). And using the shadow price structure, it is possible to evaluate the economics of alternative investments, cost structures, or export possibilities not included in the model itself, by using the model's shadow prices as inputs in a discounted cost-benefit calculation.

Implementation

The purpose of this section is to describe how the model has been implemented. The data for the model, which include the constants and

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[22] This upper bound need not be binding.

coefficients which were referred to in previous sections, were provided by the project researchers working on the supply and demand sides respectively.[23] The model is set up using the GAMS (Generalized Algebraic Modelling System) program developed by Mr. A. Meeraus of the World Bank and solved on a CDC CYBER computer.

Data

The model includes nine pools from which it makes investment and production decisions. The basic data are shown in Table 1, with the names of the pools alongside the rows. The first numeric column of this table contains the total capital investment required per Mcf for capacity expansion. Note that we assume that no additional investment will be required for the discovered Alberta fields. The last column has our assumptions about the average gestation lag between when investment expenditures are first incurred and when the investment comes on stream. The annual charges are spread evenly across periods for that number of years. Once capacity is installed, the number of years it lasts until replacement is needed is shown in the fourth column of the table. Operating costs and estimated reserves are listed in columns 2 and 3 respectively. Finally, the initial runs all assume that no more than 5% of remaining reserves can be produced in any one year.

Table 2 contains the assumptions about pipeline charges and capacity, from regions of Canada to the United States border. These are broken down by region of origin and region of destination. The implicit assumption is that these capacities will be available regardless of the model's decisions about export volumes. Of course, if results indicate that pipeline capacity is a

[23] See those chapters of the report for a complete discussion of this work, which is only summarized in numeric form in the coefficients of the model.

binding constraint on future optimal export volume growth, this indicates that the economics of capacity expansion should be examined carefully.[24]

As described previously, export demand to each of the three United States markets is characterized as a series of linear step functions; in this case we have six steps. For each year, market, and step, three numbers are given to the model: quantity demanded, average price if that were the quantity sold, and the average royalty rate associated with that quantity of sales. For reasons described in the chapter dealing with the United States outlook, the demand functions have different shapes and growth patterns between 1985-90, 1991-93, and from 1994 on.

The parameters are shown in Table 3. In all years, we segment the demand functions at the same price points; therefore, the prices and royalties at each of the six grid points are identical for all years. The quantities associated with each of the six points on the demand function are presented for 1985, 1991, and 1994. The 1985 quantities hold until 1991, when demand shifts to the new functions for the period until 1994. After 1994, these quantities can grow at specified rates which can differ across markets. In the case reported here, however, we have held the demand functions constant. These functions and how they change over time are extremely important parameters for the model, the solutions being quite sensitive the shape of the functions. Therefore, considerable experimentation has been done with other values for the demand functions and their future growth rates.

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[24] As noted previously, because of scale economies, this should be done by specifying a discrete set of alternative pipeline investments and then solving the model using a mixed integer programming algorithm. Although more costly in computer time, this does not increase the difficulty of formulating the model, since these types of activities are easily handled in the GAMS program, which generates the model and prepares it for solution.

The discount rates which were used in these runs of the model all equalled ten percent in real terms.

Table 1: Reserve Pool Data

		Cap. Cost $/MCF	Oper. Cost $/MCF	Est. Reserves TCF	Equip. Life years	Gest. Period years
GAS-1	Discovered Alberta	NA	.3	40	NA	NA
GAS-2	Discovered Shut in Alberta	1	.35	7	12	3
GAS-3	Discovered Cheap Alberta	2	.4	13	12	3
GAS-4	Discovered Costly Alberta	2.5	.45	20	12	3
GAS-5	Alberta Undiscovered	5	.5	60	12	3
GAS-6	Alberta Undiscovered	7	.6	60	12	3
GAS-7	Venture Discovered	15	.2	4	12	6
GAS-8	East Coast Undiscovered	25	.3	30	9	6
GAS-9	Arctic Gas	20	.5	25	9	6

Table 2: Pipeline Data

	Capacity (Bcf)	Operating Cost ($/Mcf)
Alberta to West-Coast	872	.35
Alberta to Midwest	1000	.67
Alberta to East-Coast	600	1.55
Venture to East-Coast	200	1.80

As for Canadian domestic demand for gas, we take as given the quantities for the base year and then apply growth rates (which can vary over time, as a scenario variable) to determine future quantities that must be delivered. It is clear that more rapid growth of domestic demand will have some dampening effect on export supply. This is because greater domestic demand will force the model to use up less expensive reserves earlier, which amounts to a shift upward of the marginal cost curve for exports. In the runs reported here, a annual growth of 4% is assumed through 1991; thereafter, growth of Canadian demand is projected at 1% annually.

Illustrative Results

In this sub-section, we present results of solving all three versions of the model using the data set summarized above. The purpose is to illustrate typical results and their interpretation, and therefore, these are not necessarily the most likely or "best" set of runs that have been done with the model.

Tables 4-6 contain the projected time paths from 1985-2006 of total production from each reserve pool (omitting those which are never used), export volumes to each market, export prices, and export revenue. The results show the impact of solving the model under different behavioral rules. The lowest export volumes correspond to Version 1, where maximizing total discounted profits to Canada is the objective. At the other extreme are the projections for Version 2, where the joint benefits to the United States and Canada are maximized. Here export volumes are considerably higher, especially exports to the East Coast. In all versions, export volumes in some periods

Table 3: Export Demand Data

Base Year Prices ($/Mcf)

	Grid-1	Grid-2	Grid-3	Grid-4	Grid-5	Grid-6
West-Coast	3.35	3.10	2.85	2.60	2.35	2.10
Midwest	3.40	3.15	2.90	2.65	2.40	2.15
East-Coast	4.15	3.90	3.65	3.40	3.15	2.90

Base Year Royalties ($/Mcf)

	Grid-1	Grid-2	Grid-3	Grid-4	Grid-5	Grid-6
West-Coast	0.67	0.60	0.55	0.48	0.43	0.36
Midwest	0.44	0.38	0.29	0.21	0.10	0.06
East-Coast	0.54	0.48	0.43	0.36	0.31	0.24

1985 Quantities (Bcf)

	Grid-1	Grid-2	Grid-3	Grid-4	Grid-5	Grid-6
West-Coast	380	460	540	605	641	657
Midwest	202	350	498	611	686	718
East-Coast	-	40	117	177	214	269

1991 Quantities (Bcf)

	Grid-1	Grid-2	Grid-3	Grid-4	Grid-5	Grid-6
West-Coast	330	440	550	645	711	757
Midwest	40	250	460	636	774	868
East-Coast	-	-	115	212	287	379

1994 Quantities (Bcf)

	Grid-1	Grid-2	Grid-3	Grid-4	Grid-5	Grid-6
West-Coast	311	440	569	682	767	832
Midwest	-	250	507	731	916	1058
East-Coast	-	-	117	242	344	464

are constrained by projected pipeline capacity, particularly to the Midwest.[25] The results for Version 3 lie between these reference points. If the royalty rates were set at a higher level, export volumes would be further constrained, moving in the direction of the Version 1 projections.

In all three runs, production occurs only in Alberta, but from all six cost/resource pools in that province.[26] However, in Version 2, production is greater, implying quicker depletion of known reserves (Gas-1) and high-cost undiscovered reserves (Gas-6) is produced one period earlier.

A comparison of the net benefits of the different versions is contained in Table 7. Here, eight different measures are presented: (1) gross export revenues; (2) direct production, transport, and investment costs; (3) royalty payments; (4) net profits to Canadian producers; (5) net benefits to Canada as a whole; (6) gross utility to United States purchasers of Canadian gas; (7) net benefits to United States purchasers of Canadian gas; and (8) the sum of net Canadian and United States benefits. Each of these measures is the sum of a discounted stream covering the period 1985-2015.[27]

Net benefits to Canadian producers are the gross revenue (1), less direct costs (2), less royalty payments (3). Net benefits to Canada is net benefits to producers plus royalty payments. The net benefits to gas importers is the difference between utility (6) and import costs (1).

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[25] This does not necessarily imply that additional pipeline expansion is economic, only that the economics of such additions merit close investigation. The reason we cannot automatically conclude that new pipelines should be built is due to the strong scale economies in pipeline construction. In further work, the model could be asked to resolve with specific fixed and variable costs for new pipelines and the economics would be judged by examination of variations in the objective function.

[26] British Columbia gas is subsumed in these pools as well.

[27] We use a longer time horizon than reported in Tables 4-6 in order to reduce the terminal effects referred to in discussing model formulation.

Finally, joint benefits are the sum of (5) and (7). It is important to remember that in addition to the benefits to Canada which the model calculates as a function of exports, there are also substantial revenues associated with the sale of gas for domestic Canadian use. Since the quantities of domestic usage are taken as fixed, there is no need to include the associated benefits since they are not affected by any endogenous choice the model may make. Since export activities do affect marginal costs of all production, the cost calculations include those associated with domestic and export production. Therefore, the measurements of net benefits provide a cardinal ranking of alternatives and different scenarios, but not a complete measure of net benefits of the entire gas industry.[28]

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[28] The net benefits of exporting (discounted revenue, less discounted costs) may in some cases be less than the discounted costs of producing the gas required for domestic Canadian use. In this type of case, the net benefits to Canada that are calculated endogenously would appear as a negative number. This raises no problems in comparing solutions. All that the negative number itself implies is that we have not specifically calculated the positive, but fixed in each run, value of domestic gas.

Table 4: Version 1 Projections

Export Volumes (BCF)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	460.000	460.000	440.000	440.000	440.000	440.000	440.000	311.000
MIDWEST	611.000	498.000	585.423	507.000	507.000	507.000	507.000	283.591
EAST-COAST	177.000	177.000	212.000	116.999	116.999	232.587	116.999	0.015

Export Revenues ($ millions)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	1426.000	1426.000	1364.000	1364.000	1364.000	1364.000	1364.000	1041.850
MIDWEST	1619.150	1444.200	1584.419	1470.300	1470.300	1470.300	1470.300	876.745
EAST-COAST	601.800	601.800	720.800	427.050	427.050	793.002	427.050	0.062

Export Price ($/Mcf)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	3.100	3.100	3.100	3.100	3.100	3.100	3.100	3.350
MIDWEST	2.650	2.900	2.706	2.900	2.900	2.900	2.900	3.092
EAST-COAST	3.400	3.400	3.400	3.650	3.650	3.409	3.650	4.150

Production Levels (Bcf/year)

	1985	1988	1991	1994	1997	2000	2003	2006
GAS-1	2748.000	1587.800	1349.630	1147.185	975.108	828.842	704.515	598.838
GAS-2		304.348	304.348	258.696	219.891	186.908	158.871	135.041
GAS-3		425.627	509.701	509.701	433.246	368.259	313.020	266.067
GAS-4		317.225	761.041	838.260	712.521	605.643	514.796	437.577
GAS-5				48.580	514.332	1035.307	1274.083	1115.981

Table 5: Version 2 Projections

Export Volumes (BCF)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	657.000	657.000	757.000	832.000	832.000	832.000	767.000	682.000
MIDWEST	718.000	718.000	868.000	1000.000	1000.000	1000.000	916.000	565.964
EAST-COAST	269.000	269.000	287.000	242.000	242.000	344.000	117.000	0.016

Export Revenues ($ millions)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	1379.700	1379.700	1589.700	1747.200	1747.200	1747.200	1802.450	1773.200
MIDWEST	1543.700	1543.700	1866.200	2243.535	2243.535	2243.535	2198.400	1593.191
EAST-COAST	780.100	780.100	904.050	822.800	822.800	1083.600	427.050	0.062

Export Price ($/Mcf)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	2.100	2.100	2.100	2.100	2.100	2.100	2.350	2.600
MIDWEST	2.150	2.150	2.150	2.244	2.244	2.244	2.400	2.815
EAST-COAST	2.900	2.900	3.150	3.400	3.400	3.150	3.650	3.900

Production Levels (Bcf/year)

	1985	1988	1991	1994	1997	2000	2003	2006
GAS-1	3144.000	1528.400	1299.140	1104.269	938.629	797.834	678.159	576.435
GAS-2		350.000	297.500	252.875	214.944	182.702	155.297	132.002
GAS-3		565.217	565.217	480.435	408.370	301.838	301.838	256.563
GAS-4		700.383	778.211	778.211	661.479	556.596	478.768	406.953
GAS-5			659.228	1196.633	1641.677	2182.400	2087.225	1834.926
GAS-6								

Table 6: Version 3 Projections

Export Volumes (BCF)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	540.000	540.000	550.000	569.000	569.000	569.000	569.000	492.767
MIDWEST	611.000	498.000	636.000	731.000	507.000	731.000	507.000	507.000
EAST-COAST	177.000	177.000	212.000	241.999	241.999	241.999	241.999	116.999

Export Revenues ($ millions)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	1539.000	1539.000	1567.500	1621.650	1621.650	1621.650	1621.650	1469.391
MIDWEST	1619.150	1444.200	1685.400	1937.150	1470.300	1937.150	1470.300	1470.300
EAST-COAST	601.800	601.800	720.800	822.800	822.800	822.800	822.800	427.050

Export Price ($/Mcf)

	1985	1988	1991	1994	1997	2000	2003	2006
WEST-COAST	0.933	1.283	1.648	1.738	1.820	1.593	1.804	1.997
MIDWEST	1.253	1.603	1.968	2.058	2.140	1.913	2.124	2.317
EAST-COAST	2.133	2.483	2.848	2.938	3.020	2.793	3.004	3.197

Production Levels (Bcf/year)

	1985	1988	1991	1994	1997	2000	2003	2006	
GAS-1	2828.000	1575.800	1339.430	1138.515	967.738	822.577	699.191	594.312	505.165
GAS-2		304.348	304.348	258.696	219.891	186.908	158.871	135.041	114.785
GAS-3		495.024	575.746	489.384	415.977	353.580	300.543	255.462	217.142
GAS-4		339.828	825.240	825.240	701.454	596.236	440.696	440.696	374.592
GAS-5			40.532	568.586	804.038	1428.069	1619.985	1650.154	2083.296
GAS-6									265.274

Table 7: Summary of Results

(Units: millions of 1985 U.S. Dollars)

	Version 1	Version 2	Version 3
Export Revenue	13237	15916	14804
Direct Costs	9021	13571	10420
Royalty Payments	2181	3036	5021
Net Profits, Producers	2035	-691	-636
Net Profits, Canada	4216	2345	4385
Gross Utility, Importers	14546	21287	17891
Net Utility, Importers	1309	5371	3087
Joint Benefits, Canada plus United States	5525	7716	7472

A NORTH AMERICAN NATURAL GAS TRADE MODEL: PART II

by

Arthur W. Wright

A NORTH AMERICAN NATURAL GAS TRADE MODEL:

PART II

by

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Early on, the project team decided to include in its work a small modelling effort that would make it possible to explore in broad terms the costs and benefits of trade in natural gas. This effort was <u>not</u> to be the be-all and end-all of the research. Major modelling would have consumed most of the project's resources, and we were not confident that the results would justify the commitment. Rather, the intent was to develop a caricature of trade in natural gas: The likeness should be apparent, but only the prominent features would stand out. Such a model would permit us to illustrate the costs and benefits of gas trade under different assumptions about market conditions and decision making. This model would not, of course, support anything so grand as forecasts of production, consumption, or export flows.

In this first segment of the project, the modelling effort was directed to providing a means of examining the net benefits to Canada of various production and export programs. Charles R. Blitzer describes the resulting model in some detail in Part I of this paper. In essence, each run of the model calculates a time-profile of (present-value) profit-maximizing gas production and exports, given certain conditions and constraints:

(a) operating and investment costs as functions of output;
(b) required deliveries to Canadian customers;
(c) the demands facing gas sellers in three different export markets in the United States; and
(d) government policies.

The time frame of the model is from the present to 2015, in three-year intervals, 1985, 1988, etc. Although we are mainly interested in the period to

2000, the model was run to later periods (to 2009 in the runs reported here) to minimize the "end-period" distortions of intertemporal models.

In what follows, we report on a set of model runs designed to illustrate the impacts of varying either constraints or assumed market conditions. The full model results are suppressed here in the interests of space and tractability. (In his part of the present paper, Blitzer walks the interested reader through a complete set of model output for a single run.) For quick reference, here is a list of what we shall be doing to and with the model.

A. Reference case:

1. Zero growth of U.S. gas demand in those parts of the United States where Canadian gas is most likely to be price-competitive: the Pacific, Midwest, and Northeast regions. (See the Demand paper.)

2. Competitive market with existing producer royalties; sellers make their own export deals, subject to current reserve-test policies.

3. Canadian internal demand is constant until 1989, then grows at 4 percent per year through 1991 and at 1 percent per year thereafter. Internal demand has first claim on any Canadian gas production.

4. Discount rate is 10 percent. (This is a real rate of return.)

5. No specific restriction on Canadian gas exports, apart from reserve-test restrictions.

B. Two "best" behavior cases:

Modify A.2 to maximize net benefits (i) to Canada; (ii) to North America.

C. Two higher royalty cases:

Modify A.2 by (i) doubling and then (ii) tripling the royalty rate.

D. Zero-Canadian growth case:

Modify A.3 by assuming zero Canadian growth, to gauge the effect of the "Canada first" constraint.

E. Higher discount rate case:

Modify A.4 by raising the discount rate to 12.5 percent.

F. Restricted exports case:

Modify A.5 by assuming that Ottawa restricts gas exports in 1985 and 1988.

The variables that we shall focus on in discussing the model results are as follows:

Gas exports: total and regional
Export revenues: total and regional
Prices in export markets
Pipeline capacity "shadow prices"
Net benefits to the various parties.

We also examine one alternative specification of the demand curve (discussed briefly in the appendix to the Demand paper) for the reference case (A) and the maximum-benefits-to-Canada case (B.1.).

A. REFERENCE CASE

This case is best viewed as the most plausible, in our judgment. (To repeat, though, the characteristics of this or any other case are not meant to be predictions or forecasts, but rather merely illustrative.) The demand analysis suggests that zero demand growth in the three U.S. regions considered is probably the bankers' conservative projection. Canadian participants from the gas industry and relevant regulatory bodies assured us that export behavior is best modelled as competitive, with existing royalty treatment. Our projection of brisk Canadian internal demand growth into the early 1990s, followed by much less brisk though still positive growth, is derived from National Energy Board figures "interpreted" for us by an industry source. Everyone we talked to thought a real return of 10 percent was the central tendency of "hurdle" rates used in the gas business. Finally, specific export restrictions (in effect, through a decision by Ottawa that it is best to "wait" a bit) are not thought likely among the Canadian participants.

Tables A1 and A2 present the results of this "most plausible" run. Table A1 gives the figures for gas exports, revenues from exports, and prices realized f.o.b. the Canadian-U.S. border on exports, in each case, by the three U.S. demand regions and total. We report the results from 1985 out to 2003, at the three-year intervals in which the model calculates them. Table A2 reports the net-benefit results.

In Table A1, we see that Canadian gas exports to the United States are relatively robust, compared with current experience and most projections. The 1985 figure is some two-thirds greater than present readings of what the actual figure will turn out to be. (And this is inclusive of <u>increased</u> U.S. deliveries at falling prices, out of the current surplus of deliverability, through 1988. See the Demand paper.) Exports rise rapidly in the early 1990s (supported in part by major new production capacity) but soon stabilize at or around 2 Tcf a year before beginning to slack off after 2000. The means of achieving these robust export results is price competition, as the export prices show. Thus, export revenues would continue to lag despite the volume increases, as they have done since Ottawa began allowing border prices to drop in 1983. Interestingly, pipeline capacity is exceeded only in three periods, into the Midwest market. The short duration of the binding constraint, plus the relatively small values of the resulting shadow price ($0.056, $0.110, and $0.246 per Mcf) suggest that new investment would not be warranted.

Table A2 presents the components of net benefits:

(1) gross export revenues
(2) direct costs
(3) royalty payments
(4) net profits, producers
(5) net profits, Canada
(6) gross utility, importers
(7) net utility, importers
(8) joint benefits, Canada plus U.S.

In our "most plausible" run, the Canadian producers fare rather poorly compared with our other scenarios, with projected losses of some $700 million over the period.[1] Canada as a whole fares somewhat better. Adding back the royalties gives net Canadian benefits of some $2.3 billion--see item (5). Note that our model, hence also these results, ignores the benefits to Canada from selling gas to <u>Canadian</u> customers.

U.S. customers for Canadian gas realize gross "consumer surplus" of over $21 billion (see item 6). <u>Net</u> benefits, however, are only some $5.4 billion (see item 7) after royalties of $15.9 billion have been paid on export volumes.

Aggregate net benefits, the sum of items (5) and (7), total $7.7 billion in our "most plausible" case.

<u>Alternative, "flatter" demand assumption:</u>

As discussed in the appendix to the Demand paper, the demand curve assumed

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[1] All net benefit figures are present values at a real interest rate of 10 percent, stated in 1985 U.S. dollars. The reported figures for producers' profits understate actual profits realized on export sales, because they exclude revenues on domestic Canadian sales but include all costs of total gas production. A crude side calculation yields total discounted revenues on domestic Canadian sales of some US$9.5 billion over the period. Thus, the present value of gas producers' total profits in the reference case would be + US$8.8 billion, not - $0.7 billion.

in the reference case is steeper in the lower price range than at higher prices. This reflects the judgment that natural gas has captured most of the switchable boiler fuel demand. If this judgment is wrong, and it could well be, the gas export demand facing Canada could be considerably flatter in its lower regions than the reference case assumes. Accordingly, we ran the model with an alternative demand curve (given in the Demand paper appendix) that embodies such a possibility.

Compared with the reference case, assuming a "flatter" demand curve increases Canadian exports to the United States until 1994 (by +24 percent in 1988, falling to +3 percent in 1994), then reducing exports a bit from 1997 on. Export prices are the same or nearly so until 1997, when they increase by some $0.15-0.25 per Mcf. With the larger exports early and the higher prices later, export revenues are uniformly greater than in the reference case.

The figures in the net benefits calculation under the "flatter" demand assumption are also greater (with one minor exception) than in the reference case. Compared with the reference case:

royalty payments increase by 5 percent;
producer profits rise dramatically, by some $728 million;[2]
and so net profits to Canada rise by 38 percent.

Interestingly, the net utility of importers falls by a little over 3 percent, presumably the net result of greater imports at lower prices early on and smaller imports at higher prices later. Joint benefits to North America, Canada, and the United States taken together, increase by 9 percent.

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[2] A percentage change would be misleading here; see footnote 1.

Thus, if one believes in the "flatter" alternative demand curve, it implies that Canadian exports could be even larger than the already impressive amounts in the reference case, and that the means to these greater exports is to be ready to reduce prices. Our analysis also suggests that just about everybody would gain, compared with the reference case, if the "flatter" demand curve is the accurate one, and if Canadian gas producers are permitted to compete through price in exporting to the United States.

B. TWO "BEST" BEHAVIOR CASES

These two extreme cases bracket the reference case. What's "best" for Canada would be to choose export volumes collusively (e.g., through a powerful marketing board) in order to gain market power: A single decision maker would face a downward-sloping net demand for exports. In contrast, what's "best" for North America would be to remove Canadian royalties and sell gas "perfectly competitively." We examine each extreme case in turn.

1. Maximum Benefits to Canada:

Table B.1.1 shows that export volumes are substantially lower than in the reference case, enough so that pipeline capacity is never exceeded. However, export prices are substantially higher. On net, export revenues are somewhat lower, but because costs are too, the profits to Canadians are greater in this case than in the reference case.

Items (4) and (5), middle column of Table B.2, illustrate the increase in benefits to Canadians. With collusively-set export volumes, producers now make profits of better than $2 billion, while Canada as a whole reaps some $4.2 billion compared with the $2.3 billion in the reference case. Interestingly, Canadian royalty recipients lose nearly a third of their payments compared with the reference case (see item 3).

U.S. customers for Canadian gas of course now fare much worse, both gross and net. In fact, they fare enough worse that joint benefits are smaller than in the reference case, even though Canadians are better off. Reduced joint benefits from the exploitation of market power are not surprising, of course.

<u>Alternative, "flatter" demand assumption:</u>

We also ran the model with the alternative "flatter" demand curve. The consequent changes were in general smaller in magnitude than was true of the reference case, discussed above. Export volumes are somewhat greater in 1985, 1988, and 2000 (6, 17, and 1 percent, respectively) and slightly smaller in 1991 (3 percent). Export prices scacely change, and so the pattern of export revenues more or less tracks that of export volumes. The components of net benefits are all a bit higher than those reported in Table B.2., including now the net utility of importers. Thus, if Canada were able to conduct its gas export trade collusively, the specification of the lower reaches of the export demand curve facing Canada would matter less than in the reference case.

2. <u>Maximum Benefits to North America:</u>

As Charles Blitzer points out in Part I of this paper, the behavioral maximand in this case is the value to U.S. buyers of gas exports from Canada. This value is expressed as consumer surplus, which is approximated by the area under the demand curves for given export volumes, less payments to Canada for those sales. Royalties to owners of gas reserves are set at zero in this case. (Again, the model does not calculate the value to Canadians of their gas purchases, nor to Americans of their purchases of U.S. gas.)

We do not bother presenting a table of export volumes, revenues, and prices for this case. The main change from the reference case is increased volumes to the U.S. Northeast beginning in 1991. The lesson may be that Canadian gas exports to this region are especially sensitive to changes in cost (including transportation and royalties). Of course, even in the reference case, with existing royalties in effect, exports are much larger to this region than past or present levels.

The rightmost column of Table B.2 shows the net benefits of this perfectly competitive case. Relative to the reference case in the first column, export revenues rise a bit, as do royalty payments. However, so do costs, so net profits to Canadians are quite a bit smaller (see item 5). In fact, producers lose nearly $400 million more than in the reference case (see item 4). The big beneficiaries of this case are U.S. customers for Canadian gas (see item 7). Overall, North America is a bit better off, but Canadians suffer somewhat. Compared with the opposite extreme case reported in the middle column of the table, of course, Canadians lose quite a bit: more than half of the net profits.

C. <u>TWO TAX ROYALTY CASES</u>

These cases illustrate the effects of trying to move closer to the "maximum-benefits-to-Canada" or collusive case by imposing taxes on top of the royalty payments. In one case, we impose a tax equal to the existing royalty rate, and in the second we double the tax rate.

Again, we do not bother presenting a table of exports, revenues, and prices. The noteworthy impact of a tax equal to the royalty rate is to reduce, rather sharply, export volumes going to the Pacific and Northeast regions, beginning in 1991. In the year 2000, for example, exports to the Pacific region are 150 Bcf (18 percent) lower than the reference case, and those to the Northeast region are 227 Bcf (66 percent) lower. (This effect is exaggerated in the double-tax-rate case.) Interestingly, exports to the Midwest hardly budge, and in the double-tax-rate case they even increase slightly over the reference case in 2003. The combination of reduced depletion in early years and demand growth in later years overcomes the negative impact of the taxes. Once again, we see that royalties-and-taxes hit the Northeast region hardest; moreover, they could hit the Pacific region, too.

With a tax rate equal to the royalty rate, export revenues are mainly, though not uniformly, constant or higher, compared with the reference case. (Doubling the tax rate sharply reduces export revenues after 1988.) This is the net result of higher export prices but lower volumes with the extra taxes.

Table C.2 gives the net benefits for the two tax cases, together with the comparable figures for the reference and "Canadian best" cases (in the first and second columns, respectively). The most interesting comparison is with the latter. With the tax set at the royalty rate, Canadians as a group make some progress toward their best case but still fall shy of it (see item 5). Canadian producers suffer by a gross change of $4.4 billion, so the improvement for Canada is definitely at their expense! The difference, of course, is in "royalty payments" (which now should be interpreted as "royalties plus taxes"): The net take here is better than $3 billion (see item 3). With Canadians still shy of their "best" possible case, U.S. buyers do better with the tax than with the Canadian best case (see item 7), and North America as a whole is far better off (see item 8).

With the tax set at the royalty rate, the net benefits do not differ that much from those of the reference case. This is really the mirror image of the comparison with the Canadian best case.

Setting the tax at twice the existing royalty rate is a "self-inflicted wound" case. Everyone suffers, compared with the reference case, except claimants to royalties-plus-taxes. Clearly, they should be bribed to give up this case, out of the gains from <u>not</u> doubling the tax rate.

D. ZERO CANADIAN GROWTH CASE

As expected, the smaller domestic Canadian consumption of this case reduces costs a bit and therefore increases export volumes and profits somewhat. The changes are small enough, however, to support the contention in the Demand paper that internal Canadian gas demand will likely not be a binding constraint of great significance on exports southward.

Exports to the U.S. Northeast increase by about 100 Bcf in 1994. Otherwise, there is no volume effect, relative to the reference case, until 2003, when they increase to all three regions by a total of 274 Bcf. As expected, less domestic consumption postpones the eventual downturn of gas exports by 3-6 years. This is reflected in somewhat lower export prices for the corresponding periods. However, the relevant ranges of the demand functions are evidently elastic, because export revenues increase a bit.

As to net benefits, net profits to Canadians increase compared with the reference case. Producers benefit the most, their profits rising from -$692 million to +$126 million before considering domestic revenues. American gas consumers also gain a little from Canadian's energy thriftiness, and North America as a whole is better off by $1 billion. CAVEAT: We have ignored the decline in the benefits to Canada (and hence to North America) realized from domestic Canadian gas use, whose benefits are not calculated in the model. (If gas use is reduced because of increased use of lower-priced competitive fuels, the decline in gas-related benefits would be offset by an increase in benefits from the use of other fuels.)

E. HIGHER DISCOUNT RATE CASE

The "real" side of the model is remarkably resistant to an increase of 2.5 percentage points, to 12.5 from 10.0 percent, in the discount rate. The investment activity that goes on "behind" the changes in gas exports is not much affected. Compared with the reference case, exports drop in the U.S. Northeast region by 75 Bcf (26 percent) in 1991, and in the U.S. Pacific region by 46 Bcf and 65 Bcf (well under 10 percent) in 1994 and 1997, respectively. The corresponding export prices are a bit higher, and export revenues drop by nearly 25 percent in the Northeast but increase slightly in the Pacific.

The net benefits, being discounted present values, of course drop quite a bit, but do so pretty much monotonically across the eight categories that we have been using. One bright aspect is that the present value of Canadian producers' revenues recovers by better than $400 million. However, so far as the issues examined here are concerned, there is little of true interest in this variant.

F. RESTRICTED EXPORTS CASE

This case illustrates the effects of a government decision to "wait" for a short period of time, by restricting exports in the first 3-6 years of the model's "life", 1985 and 1988. This could also be viewed as a scenario in which the Canadian government drags its feet in acknowledging the new, more competitive gas market shaping up in North America. The restriction takes the form, in the model, of truncating the demand functions at "grid 4" through 1988, in effect limiting Canadian exporters' ability to sell more gas by lowering price (see the quotation at the front of the Supply paper).

As a result of the restrictions, total exports in 1985 and 1988 are some 250 Bcf lower than in the reference case. Otherwise, the export volumes do not change at all until 2003, when they increase over the reference case by all of 5 Bcf to the U.S. Northeast region. Export prices are of course higher in these two periods. Export revenues rise in the U.S. Pacific and Midwest regions, but fall in the U.S. Northeast, rising overall by a net $90 million each year.

Does it pay, in terms of net benefits? "Yes," if you are Canadian, especially if you are a Canadian producer (whose profits rise, compared with the reference case, by a billion dollars, to +$319 million). "No," if you are an American, or if you are an economist interested in maximizing total North American welfare. The net benefits to American users of Canadian gas decline by $1.3 billion, and to North America as a whole by about $400 million.

Finally, we should ask why "waiting" pays. It is emphatically <u>not</u> so that one can realize higher prices later on, at least not in our model. Export prices remain virtually constant compared with the reference case, once the restrictions have been lifted. Rather, the reason it pays (Canadians) to wait is because the export restrictions permit the exploitation of some "market power" (downward-sloping demand). Note the similarity in the direction and distribution of the gains between this case and case B.1, the Canadian-best case, above.

G. CONCLUSION

Did it pay to construct this caricature of North American gas trade? The answer is yes. With it, we have been able not to forecast and predict exports or their prices, but to explore the consequences of some interesting policy and market-condition variants relative to a "most plausible" reference case. The model was not the major product of the whole project, but it was a worthwhile component of the broader effort.

TABLE A.1 EXPORT VOLUMES, REVENUES, AND PRICES: REFERENCE CASE

EXPORT VOLUMES (BCF)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	657.0	657.0	757.0	832.0	832.0	832.0	767.0
MIDWEST	718.0	718.0	868.0	1000.0	1000.0	1000.0	916.0
NORTHEAST	269.0	269.0	287.0	242.0	242.0	344.0	117.0
TOTALS	1644.0	1644.0	1912.0	2074.0	2074.0	2176.0	1800.0

EXPORT REVENUES (MILLION $US)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	1379.7	1379.7	1589.7	1747.2	1747.2	1747.2	1802.4
MIDWEST	1543.7	1543.7	1866.2	2243.5	2243.5	2243.5	2198.4
NORTHEAST	780.1	780.1	904.0	822.8	822.8	1083.6	427.0
TOTALS	3703.5	3703.5	4359.9	4813.5	4813.5	5074.3	4427.8

EXPORT PRICES ($US/MCF)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	2.10	2.10	2.10	2.10	2.10	2.10	2.35
MIDWEST	2.15	2.15	2.15	2.24	2.24	2.24	2.40
NORTHEAST	2.90	2.90	3.15	3.40	3.40	3.15	3.65

Table A.2. Net Benefits, Reference Case

(10^6 U.S. $1985)

(1)	Export Revenues	15,916
(2)	Direct Costs	13,571
(3)	Royalty Payments	3,037
(4)	Net Profits, Producers*	-692
(5)	Net Profits, Canada	2,345
(6)	Gross Utility, Importers	21,287
(7)	Net Utility, Importers	5,371
(8)	Joint Benefits, Canada and U.S.	7,717

Note: (4) = (1) - (2) - (3)

(5) = (4) + (3)

(7) = (6) - (1)

(8) = (5) + (7)

* Net profits to producers are understated (and may even be negative) because they omit revenues from domestic Canadian sales. A rough estimate of the present value of those sales over the period 1985-2009 is $9.5 billion; see footnote 1 in the text.

TABLE B.1.1 EXPORT VOLUMES, REVENUE, AND PRICES: MAXIMUM BENEFIT TO CANADA

EXPORT VOLUMES (BCF)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	460.0	460.0	440.0	440.0	440.0	440.0	440.0
MIDWEST	611.0	498.0	585.4	507.0	507.0	507.0	507.0
NORTHEAST	177.0	177.0	212.0	117.0	117.0	232.6	117.0
TOTALS	1248.0	1135.0	1237.4	1064.0	1064.0	1179.6	1064.0

EXPORT REVENUES (MILLION $US)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	1426.0	1426.0	1364.0	1364.0	1364.0	1364.0	1364.0
MIDWEST	1619.2	1444.2	1584.4	1470.3	1470.3	1470.3	1470.3
NORTHEAST	601.8	601.8	720.8	427.0	427.0	793.0	427.0
TOTALS	3647.0	3472.0	3669.2	3261.3	3261.3	3627.3	3261.3

EXPORT PRICES ($US/MCF)

	1985	1988	1991	1994	1997	2000	2003
PACIFIC	3.10	3.10	3.10	3.10	3.10	3.10	3.10
MIDWEST	2.65	2.90	2.70	2.90	2.90	2.90	2.90
NORTHKEAST	3.40	3.40	3.40	3.65	3.65	3.41	3.65

Table B.2. Net Benefits, "Best" Cases

(10^6 U.S. $1985)

		Ref. Case	Canadian Best Case	No. American Best Case
(1)	Export Revenue	15,916	13,237	16,683
(2)	Direct Costs	13,571	9,021	14,596
(3)	Royalty Payments	3,037	2,181	3,153
(4)	Net Profits, Producers*	-692	2,035	-1,067
(5)	Net Profits, Canada	2,345	4,216	2,087
(6)	Gross Utility, Importers	21,287	14,546	22,375
(7)	Net Utility, Importers	5,371	1,309	5,692
(8)	Joint Benefits, Canada & U.S.	7,717	5,525	7,779

Note: (4) = (1) - (2) - (3)

(5) = (4) + (3)

(7) = (6) - (1)

(8) = (5) + (7)

* Net profits to producers are understated (and may even be negative) because they omit revenues from domestic Canadian sales. A rough estimate of the present value of those sales over the period 1985-2009 is $9.5 billion; see footnote 1 in the text.

Table C.2. Net Benefits, "Tax" Cases

(10^6 U.S. \$1985)

	Ref. Case	Canadian Best Case	Tax at Roy. Rate	Tax at Twice Roy. Rate
(1) Export Revenues	15,916	13,237	14,099	10,198
(2) Direct Costs	13,571	9,021	11,283	8,745
(3) Royalty Payments	3,037	2,181	5,217	5,179
(4) Net Profits, Producers*	-692	2,035	-2,401	-3,726
(5) Net Profits, Canada	2,345	4,216	2,816	1,453
(6) Gross Utility, Importers	21,287	14,546	18,322	13,589
(7) Net Utility, Importers	5,371	1,309	4,223	3,391
(8) Joint Benefits, Canada & U.S.	7,717	5,525	7,039	4,844

Note: (4) = (1) - (2) - (3)

(5) = (4) + (3)

(7) = (6) - (1)

(8) = (5) + (7)

* Net profits to producers are understated (and may even be negative) because they omit revenues from domestic Canadian sales. A rough estimate of the present value of those sales over the period 1985-2009 is $9.5 billion; see footnote 1 in the text.

TECHNOLOGICAL OPPORTUNITIES FOR NATURAL GAS DEMAND

by

David C. White

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PREFACE

The following discussion is intended to be taken as speculative. The task given was to reflect on the possible impact technical change might have on natural gas demand. The prospects for technology change outlined here are quite possible, but do depend on a number of engineering and economic developments occurring in the future.

The underlying assumptions here require more time than was available for careful reworking, but the recalculations will be done in the months ahead. For now, the demand projections should be considered speculative, since they depend on developments not now commercially available.

INTRODUCTION

The consensus projections for gas demand to the year 2000 are generally stable or declining. These projections normally assume currently available gas consuming equipment and retention of the 1978 Fuel Use Act. The gas utility industry, primarily through participation in the R&D programs of the Gas Research Institute (GRI), is working to improve the efficiencies of existing equipment and develop new gas-consuming devices that will help build demand.

Principal R&D efforts to increase economic competitiveness by efficiency improvements have been focused on residential gas furnaces (pulse combustion furnace GRI-LENNOX) and industrial process heat applications (process dying, steel ladle heaters, etc.). The various programs that are under way or have been successfully completed are reported in the Gas Research Institute Research and Development Plan 1986-1990 [1] and two Status Reports [2,3]. The R&D efforts to improve efficiency will help retain markets, but overall they offer little or no potential for demand growth.

The Gas Utility R&D for new gas-consuming equipment that will help retain markets and potentially build demand is focused on the following applications:

<u>Residential</u>

Natural gas-fired engine-driven heat pumps

Natural gas-fired air conditioning, both engine-driven and absorption types

<u>Commercial</u>

Natural gas-fired engine-driven heat pumps and air conditioning systems

Natural gas fuel cells

<u>Industrial</u>

Cogeneration systems:

Gas turbine-process steam
Diesel/gas (usually spark ignition if using gas)-process steam

<u>Transportation</u>

Compressed natural gas vehicles

Dual fuel vehicles
Dedicated natural gas vehicles

The other potential major technology for increasing gas demand is the use of gas turbines or gas turbine combined cycle systems (GTCC) in electric utility applications. Several electric utility companies are currently planning GTCC installations based on using middle distillate [4] or using natural gas by obtaining a Federal Energy Regulatory Commission (FERC) waiver of the Fuel Use Act for a specified period (usually 10 years). The Electric Power Research Institute (EPRI) is currently performing a detailed analysis of the phased installation of integrated gasifier gas turbine combined cycle systems starting with gas turbines, adding later a heat recovery steam cycle to produce a combined cycle system, and later the addition of a front-end coal gasifier to produce an integrated gasifier-gas turbine combined cycle gasifier system (IGTCC). The final integrated system is modeled after the demonstration IGTCC system now operating on the Southern California Edison system at Cool Water, California. This demonstration was developed under EPRI sponsorship with multi-industry funding: EPRI, Southern California Edison, Texaco, General Electric, Bechtel, and Japanese utilities. A detailed report on the economics of phased IGTCC systems is being done by Fluor for EPRI and a draft report is available [5].

The gas-fired engine-driven heat pump system is technically feasible. The additional cost and maintenance of such systems must be weighed against their improved efficiency over furnaces for heating and the ability to operate in a cooling mode. For heating, coefficients of performance (COP) from 1.2 to 1.7 are attainable and for cooling, COPs of 0.6 to 1 may be obtained. The competitive system is the electric heat pump. In very cold climates, the gas-fired heat pump is superior for heating and in warm climates the electric heat pump is best for cooling. In small sizes (particularly residential applications) the gas-fired systems are not competitive with electric systems. In large systems (commercial applications) either gas or electric may prove the best choice. In any system comparison, size, operating conditions, regional temperature, and gas and electricity prices must be considered. Both GRI and EPRI are supporting research on improving the performance and cost of their respective systems, and over time, systems with improved efficiencies will be marketed.

An assessment of current and projected technology was done by GRI [6] and some of the results are shown in Figures 1 and 2 [6]. While the development of new and improved technology may help to retain current demand, there is no basis for projecting a signficiant natural gas demand growth in either the residential or commercial space conditioning market.

The major opportunities for new natural gas demand through the use of new technology are region-dependent but, in sequence of total potential demand, they are:

Electric Utilities--Phase construction of IGTCC electric power plants

Industrial--Cogeneration in high load factor industrial plants

Transportation--Fleet use of compressed natural gas fueled vehicles

The following sections will develop some estimates for natural gas demand growth potential for (1) electric utility phased IGTCC power plants, (2) industrial cogeneration, and (3) compressed natural gas fueled vehicles.

Figure 1 [4]

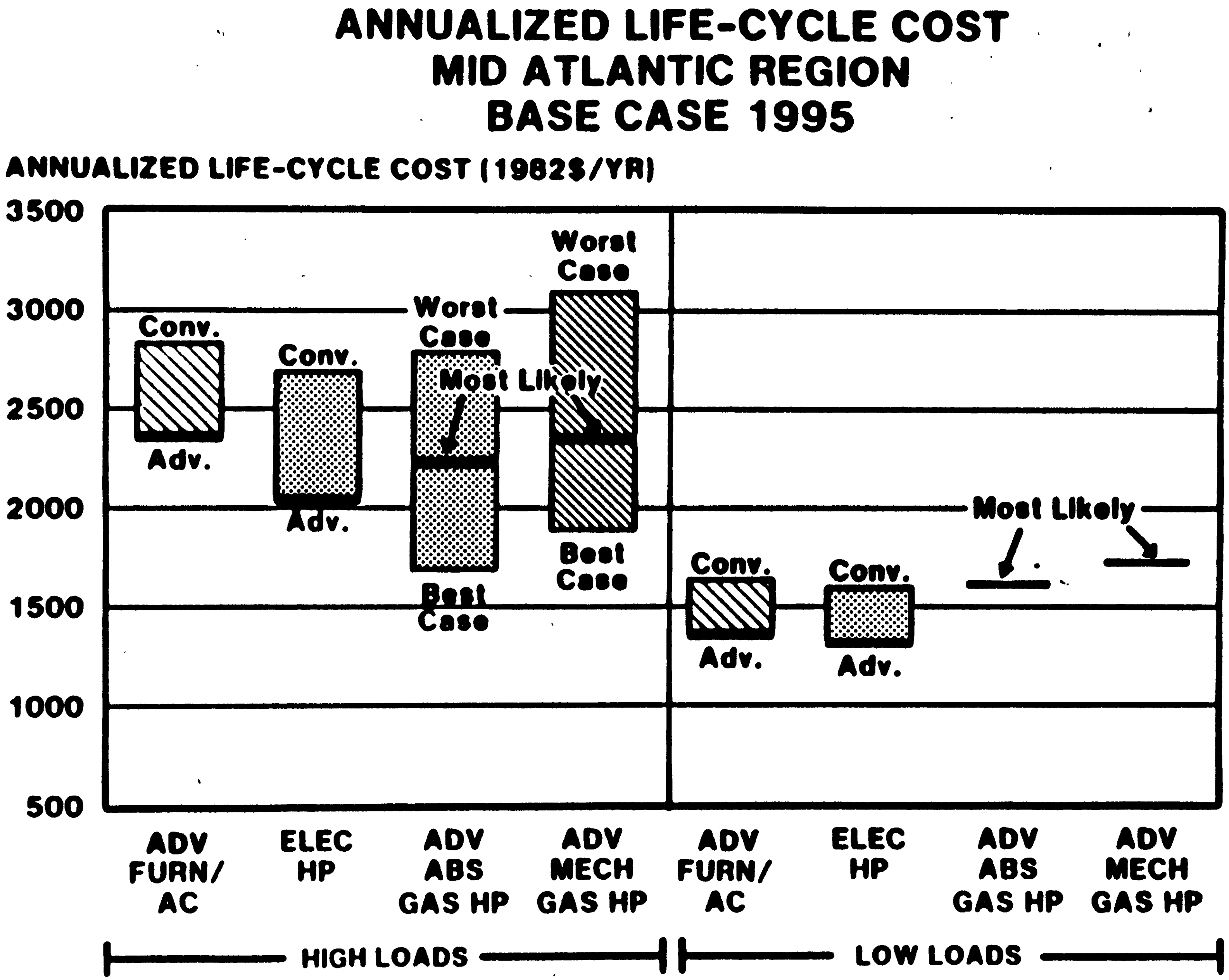
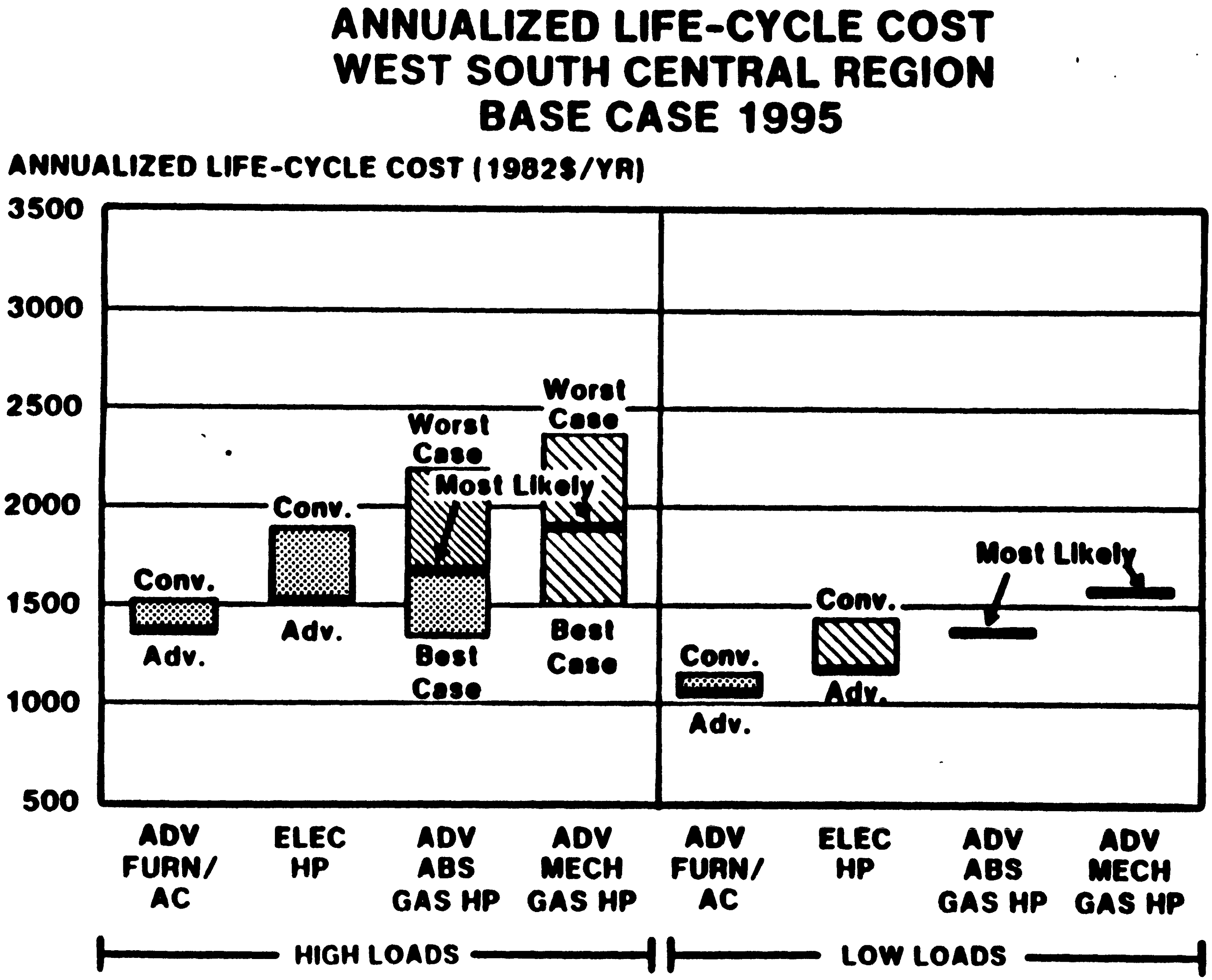

ANNUALIZED LIFE-CYCLE COST
MID ATLANTIC REGION
BASE CASE 1995
ANNUALIZED LIFE-CYCLE COST (1982$/YR)
3500
3000
2500
2000
1500
1000
500
Conv.
Adv.
Conv.
Adv.
Worst Case
Most Likely
Best Case
Worst Case
Best Case
Conv.
Adv.
Conv.
Adv.
Most Likely
ADV FURN/ AC
ELEC HP
ADV ABS GAS HP
ADV MECH GAS HP
ADV FURN/ AC
ELEC HP
ADV ABS GAS HP
ADV MECH GAS HP
HIGH LOADS
LOW LOADS

Figure 2 [4]


ANNUALIZED LIFE-CYCLE COST
WEST SOUTH CENTRAL REGION
BASE CASE 1995
ANNUALIZED LIFE-CYCLE COST (1982$/YR)
3500
3000
2500
2000
1500
1000
500
Conv.
Adv.
Conv.
Adv.
Worst Case
Most Likely
Best Case
Worst Case
Best Case
Conv.
Adv.
Conv.
Adv.
Most Likely
ADV FURN/ AC
ELEC HP
ADV ABS GAS HP
ADV MECH GAS HP
ADV FURN/ AC
ELEC HP
ADV ABS GAS HP
ADV MECH GAS HP
HIGH LOADS
LOW LOADS

ELECTRIC UTILITY USE OF NATURAL GAS

The electric utility industry currently uses [7] approximately 3 Tcf of natural gas, of which two-thirds are firm contracts and one-third interruptable. Of this gas, over 98% is used in steam boilers and approximately 1.2% for combustion turbine peaking power. The North American Electric Reliability Council (NERC) projections [7] for natural gas usage in 1992 is for 20% less gas.

The potential for increased use of natural gas by electric utilities is difficult to fully assess. It also must be recognized that for such applications, natural gas and middle distillate fuels are completely substitutable--price determines the choice. An indication of this potential market can be obtained by using a recent study by Tabors and Flagg of the M.I.T. Laboratory for Electromagnetic and Electronic Systems (LEES) [8], who used the EPRI Electric Generation Expansion Analysis System (EGEAS) to project the generation choice for the period 1990 to 2004 for the six "model" EPRI regional utilities. The growth rates used in these studies were NE 2.1%, SE 3.7%, EC 3.5%, SC 4.2%, WC 3.2%, and W 3.5%. These are approximately 0.1 to 0.2 percentage points higher than the 1983-1992 growth rates projected by NERC [7]. The capital costs and heat rates used by Tabors et al. for the plant types considered updated to ($1984) were:

Table 2

PLANT COSTS AND HEAT RATES [8]

Btu/kWhr	($1984)	Heat Rate
Light water reactor	2100	10,700
Atmospheric fluid bed coal (AFB)	950	9,640
Gas turbine combined cycle	330	7,260
Advanced gas turbine combined cycle (GTCC)	480	6,210
Advanced combustion turbine	250	10,300

Comparing these numbers to data from the EPRI/Fluor study (still in draft form) [5] for advanced gas turbine and combined cycle systems, we have typically:

Table 2

PLANT COSTS AND HEAT RATES [5]

EPRI/Fluor	Capital Cost ($1984)	Heat Rate (Btu/kWhr)
Advanced gas turbine combined cycle	500	8,000
Advanced combustion turbine	250	11,900

Thus, the capital costs of the Tabors study are equivalent to the EPRI/Fluor study, but the heat rate is 15 to 20% low and will understate the fuel usage, and hence fuel costs in their expansion planning study. However, the data used are sufficiently representative that their conclusions can be used as an indicator of potential gas demand derived from electric utility installations of gas turbine combined cycle (GTCC). These systems designed for natural gas could ultimately be converted to integrated gasifier gas turbine combined cycle systems when the cost of gas increases enough to make the capital cost of the gasifier economically feasible.

The low capital costs--$250/kW for combustion turbines and $500/kW for the GTCC system fired with natural gas at $4.00 MMBtu--make the GTCC systems a dominant choice in four of six model EPRI regional utilities for the 1990-2004 planning period. The essential results of the Tabors study [8] can be gleaned from the relative amount of GTCC installed in the terminal year 2004 of the study.

Table 3

GTCC INSTALLED BY YEAR 2004 [8]

	GTCC MW	TOTAL MW
NE (Northeast)	12,000	12,000
SE (Southeast)	16,000	16,000
EC (East Central)	9,000	16,000
SC (South Central)	13,000	25,000
WC (West Central)	9,000	17,000
W (West)	500	12,000

The choice of unit additions from the available technologies considered in Table 1 were either GTCC or AFBC, and the MW additions for each were approximately linear over the 15-year planning study. The essential feature of the study is that on the eastern seaboard, where coal costs are high, the choice is 100% GTCC. In the three central regions, gas and coal are competitive and split the market 50-50. In the west, the low coal costs capture the total market. Based on this study, the projected incremental gas consumption by regions are:

Table 4 [8]

INCREMENTAL GAS CONSUMPTION 10^6 Mcf

Region	1990	1994	1999	2004
NE	420	1040	1690	2410
SE	80	710	1900	350
EC	0	230	360	640
SC	0	280	340	640
WC	30	130	400	710
W	0	60	10	20
TOTAL	530	2450	4700	7770

The projected natural gas demand of 0.5 Tcf in 1990 to almost 8 Tcf in 2004 is 80% consumed on the eastern seaboard (NE and SE). Thus, if this scenario is to be considered, the availability and price of natural gas in the eastern states becomes a critical factor. For the early 1990s, the lower capital costs and rapid construction potential for the GTCC system are a powerful driving force. By the mid- to late 1990s, the coal gasifier technology should be fully commercial, so for an additional $800/kW ($1984), an environmentally clean coal-fired base load plant can be available, which is already producing revenue and whose capital costs are partially in the rate base. The phased construction being studied by EPRI gives the additional dimension to the Tabors-Flagg study to make their results usable on the basis to project potential electric utility natural gas demand to the year 2000. Even if their results are 50% too high, they still project a +200% growth in natural gas consumed by the electric utility industry.

The Tabors-Flagg study did some fuel and capital sensitive studies. For a 25% increase in fuel cost, $4.00 to $5.00/MMBtu, the choice of gas turbine combined cycle units is not made until approximately 1995. This sensitivity to fuel price and consequently also to heat rate needs more attention. The study used heat rates that were 15 to 20% low and thus there is a bias toward GTCC that may significantly overstate their choice under realistic conditions. However, today installation of phased GTCC systems are being planned and typical data are given in Table 5 and Figures 3 and 4 [4]. The potential for reducing risk in uncertain load growth projections and spreading capital commitments over a longer time period are factors not included in the Tabors-Flagg study and may help counterbalance the negative effect of higher heat rates or higher natural gas costs.

INDUSTRIAL COGENERATION

The installation of cogeneration facilities becomes economic when the electric power generated produces revenue (or savings) that justify the additional capital required for a cogeneration facility over a simple steam raising faciliy. For plants in the range of 125 x 10^6 Btu/hr to 1000 x 10^6 Btu/hr, the additional capital for the cogeneration part of the system is approximately 130% for the smaller and 85% for the larger systems. Thus a cogeneration plant will involve a capital investment approximately two times that of a boiler producing process steam. The ability to generate enough revenue from electricity production to justify the larger capital makes cogeneration systems very sensitive to the plant steam load factor. In general, load factors at least 50% or larger are required for cogeneration to be feasible.

Table 5

TYPICAL DATA ON PHASED CONSTRUCTION OF SYSTEMS COMPOSED OF GAS TURBINE, STEAM CYCLE, AND COAL GENERATION

EQUIPMENT	UNIT COSTS ($/KW)**		88°F AMBIENT* HEAT RATE (Btu/Kw)	FUEL
	1 Unit	2 or 3 Units		
Current Gas Turbine	260	245	12,300	NG or Middle Dist.
Advanced Gas Turbine	240	230	11,900	NG or Middle Dist.
Gas Turbine and Steam Cycle	-	500	8,000	NG or Middle Dist.
PHASED IGCC				
Current GCC + Texaco Gasifier		1420	10,100	Coal
Advanced GCC + Texaco Gasifier		1320	9,600	Coal
Advanced GCC + Texaco Gasifier (gas quench)		1270	10,100	Coal
Advanced GCC + Texaco Gasifier (radiant and convective coolers)		1380	9,000	Coal
UNPHASED IGCC				
Advanced Gas Turbine and Texaco Gasifier		1308	9,600	Coal

*Heat rate 100% - 88°F - 100% load
97% - 20°F - 100% load
95% - 20°F - 130% load

**($ Jan. 1984)

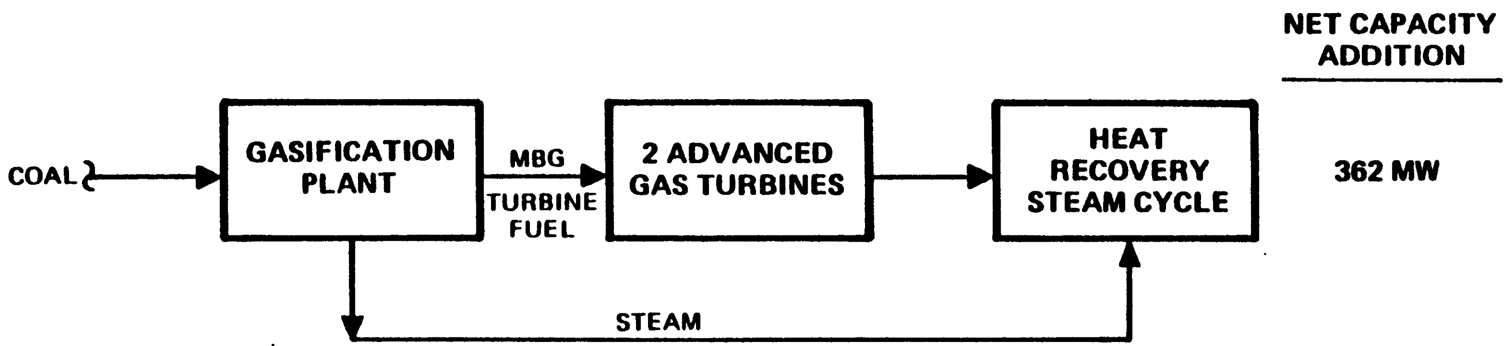
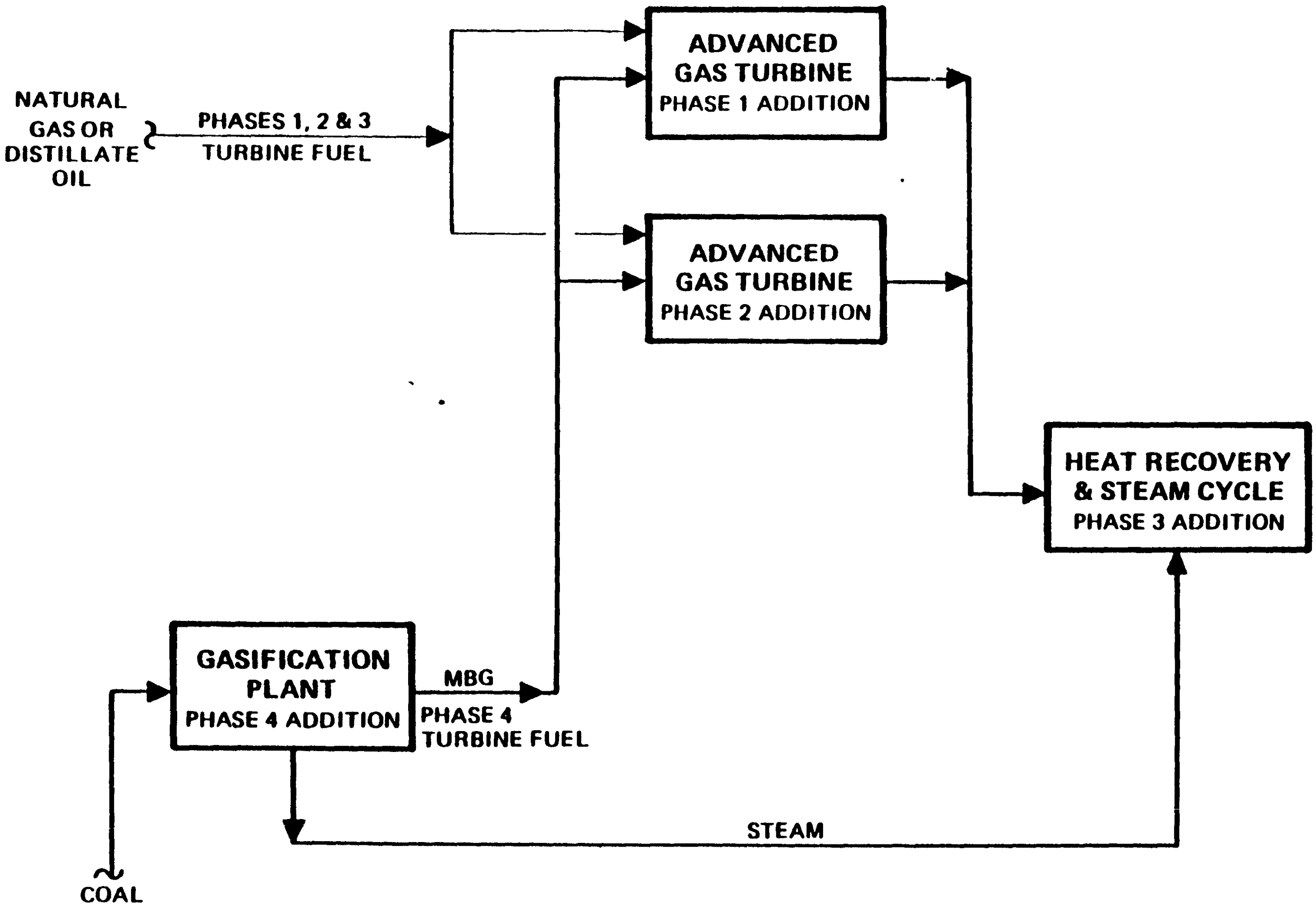


Figure 3. UNPHASED GCC PLANT PHASING SEQUENCE [5]



PHASE	NET CAPACITY ADDITION
1	104 MW
2	104 MW
3	102 MW
4	52 MW
	362 MW

FIGURE 4. PHASED CDD PLANT (SEPARATE STEAM CYCLE PHASE) PHASING SEQUENCE [5]

A DOE study [9] using a real rate of return greater than 7% indicates there could be a potential 39,000 MW of cogeneration installed in industrial sites by the year 2000. Eighty percent of the plants and 90% of the power are in six major industrial sectors (SIC 20 - Food; SIC 22 - Textile Mill Products; SIC 26 - Pulp and Paper; SIC 28 - Chemicals; SIC 29 - Petroleum and Coal Products; SIC 33 - Primary Metals) (see Table 6). Over 40% of the power produced is in plants from 10 to 50 MW in size and nearly two-thirds in plants between 2 and 50 MW. The total potential natural gas demand represented by these industrial cogeneration facilities is between 2 and 3 Tcf. Natural gas will have to compete in price with middle distillate and residual fuel oil to obtain this market. Dual fuel capability is usually standard practice in package boilers and cogeneration facilities.

Summaries of the results of the DOE study are given in Table 6 and Figures 5, 6, and 7. Regionally, 40% of the cogeneration potential is along the eastern seaboard states and 24% in the Southwest (see Table 7 and Figure 8). The cogeneration potential is greatest, therefore, in those areas where for electric utilities the gas turbine combined cycle systems are most promising. The Tabors study [8] projected 28 MW additional capacity to utilities along the eastern seaboard. The industrial cogeneration potential in this same region is approximately 16 MW. Since both are supplying the same electricity demand, the industrial cogeneration installed will reduce the need for utility generating capacity. Should the full industrial cogeneration potential be installed, the need for electric utility capacity would be reduced correspondingly. The opportunity for

Table 6

POTENTIAL NUMBER OF COGENERATION PLANT SITES,
MEGAWATTS AND SIZES FOR ROI 7% (uninflated) [9]

SIC	Potential MW	%	Potential No. of Plants	%
20	7005	18	734	20
22	1882	5	499	14
26	7962	20	437	12
28	10,316	26	547	16
29	5836	15	236	6
33	2397	6	434	12
Remaining Sectors	3950	10	730	20
TOTAL	39,348	100	3644	100

Size (MW)	Total MW Production	%
2	1162	3
2 - 10	7844	20
10 - 50	16,881	43
50 - 100	7621	19
100	5842	15
TOTAL	39,348	100

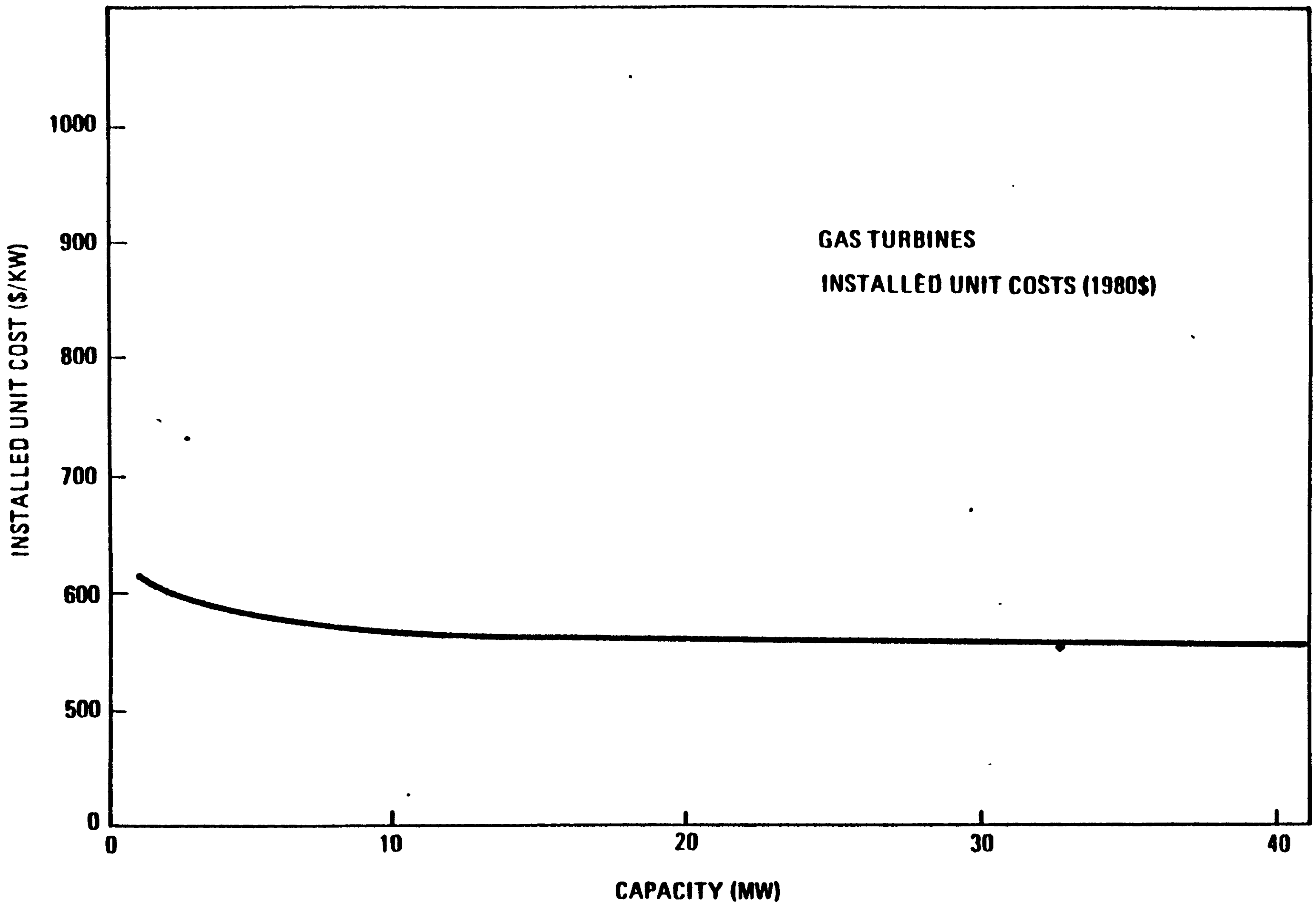


FIGURE 5. CAPITAL COSTS OF COGENERATION SYSTEMS (CONTINUED) [9]

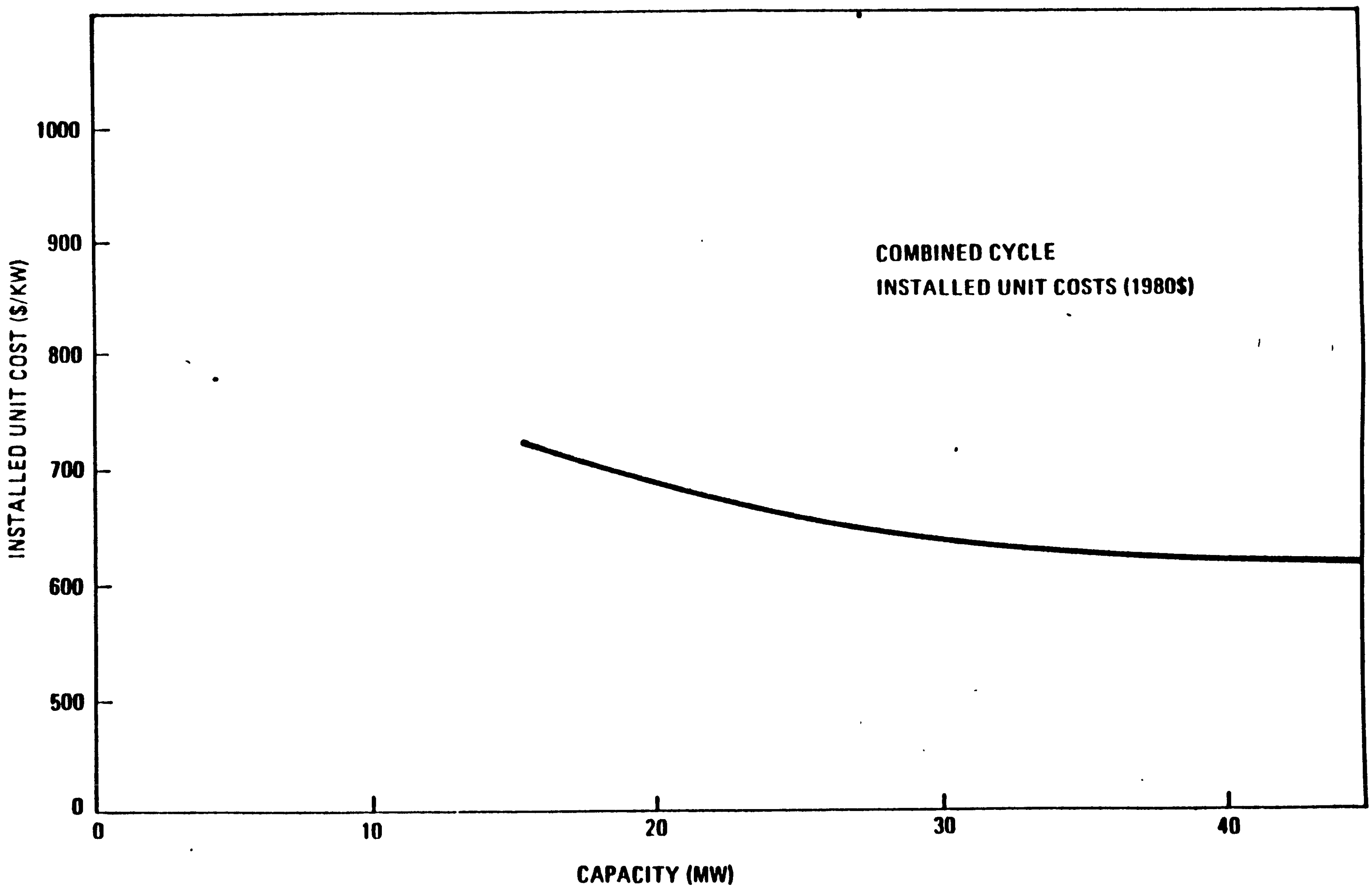


FIGURE 6. CAPITAL COSTS OF GENERATION SYSTEMS (CONTINUED) [9]

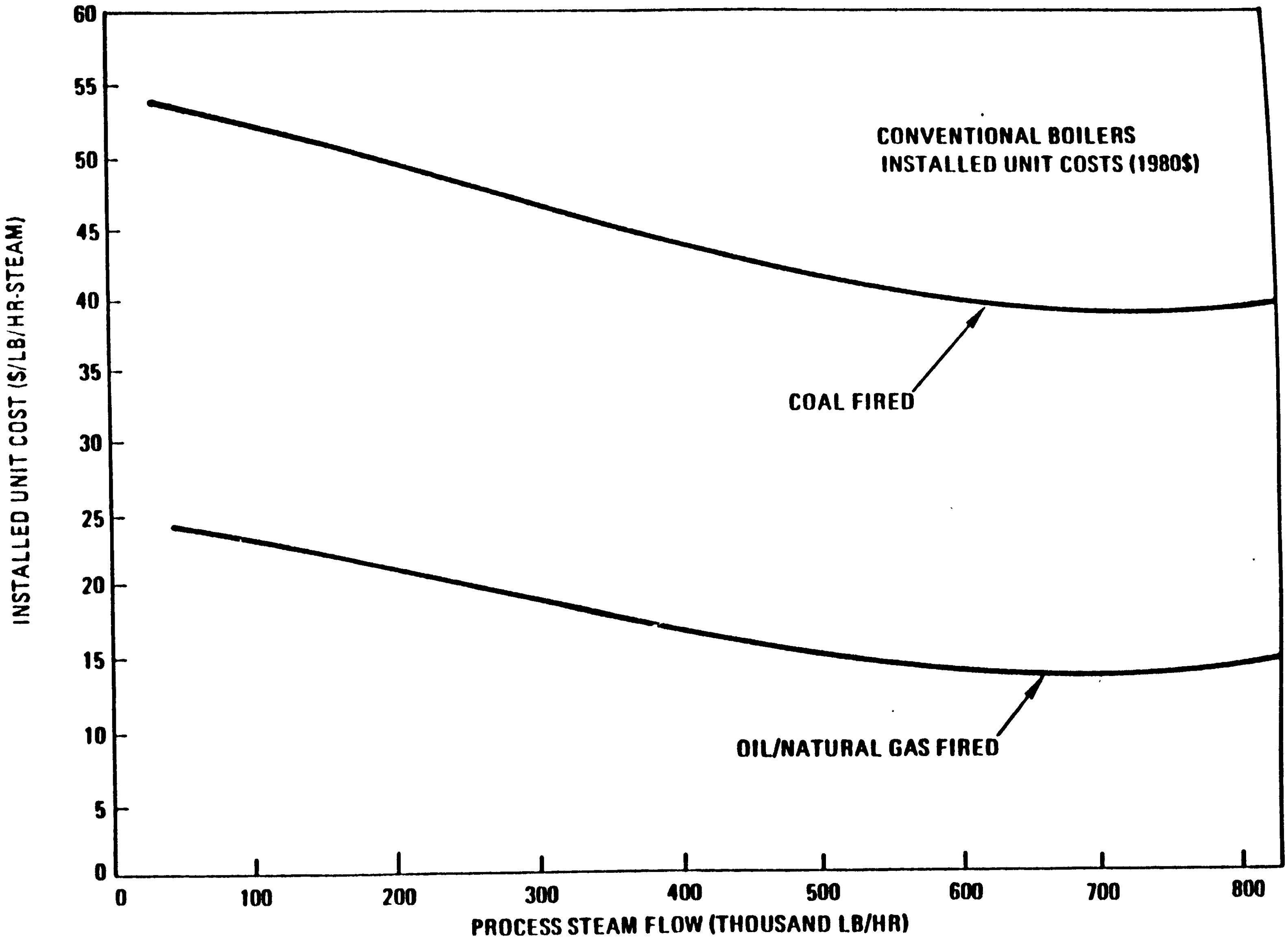
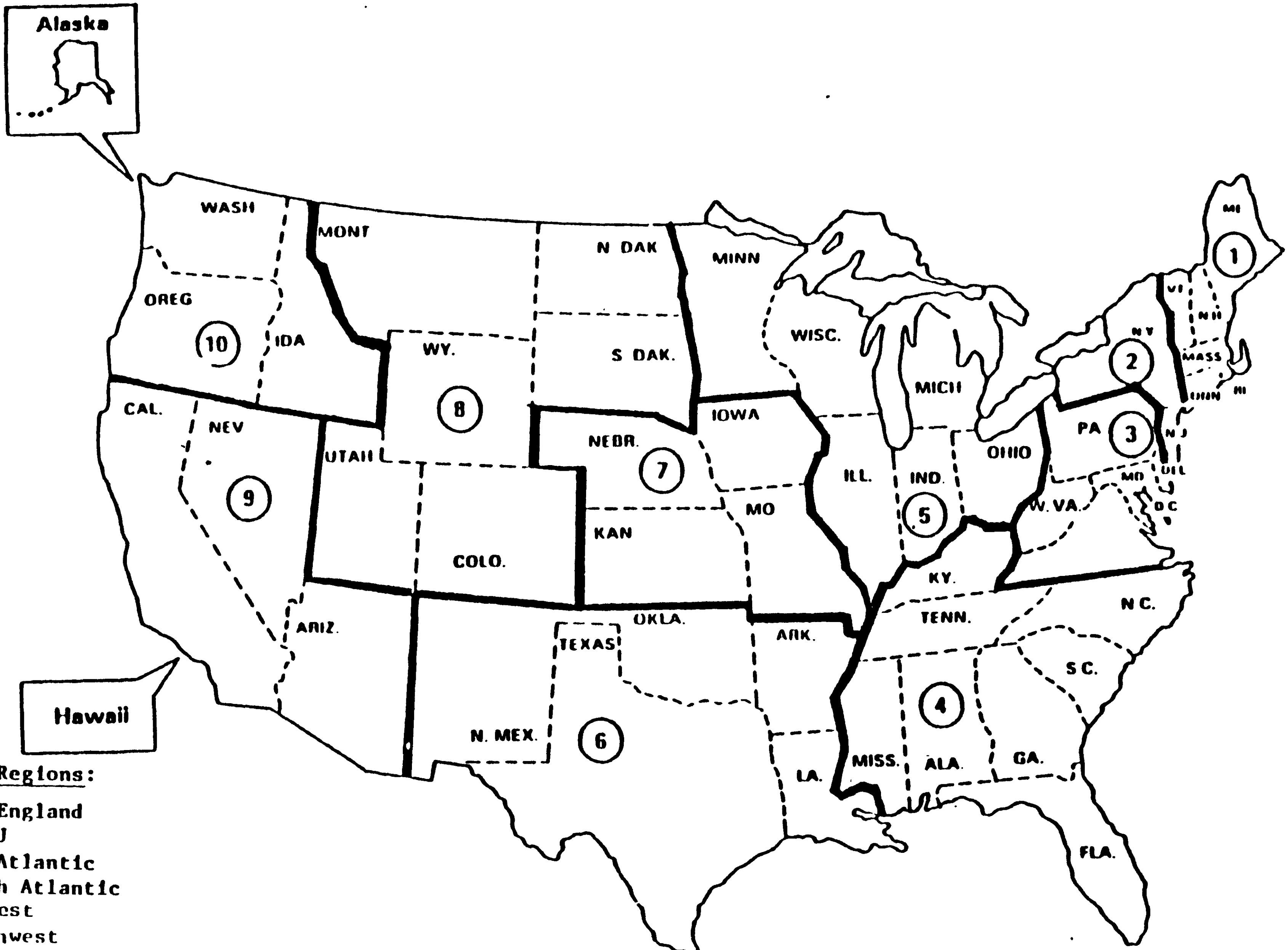


FIGURE 7. CAPITAL COSTS OF COGENERATION SYSTEMS (CONTINUED) [9]

Table 7

SUMMARY OF COGENERATION POTENTIAL BY REGION

Region	Number of Potential Plants	Potential Power Generation (MW)
New England	189	1690
NY/NJ	540	3544
Mid Atlantic	470	4155
South Atlantic	679	6368
Midwest	850	6255
Southwest	348	9442
Central	121	1553
North Central	28	736
West	359	4241
Northwest	60	1360
Total	3644	39344



Regions:

1. New England
2. NY/NJ
3. MID Atlantic
4. South Atlantic
5. MIDwest
6. Southwest
7. Central
8. North Central
9. West
10. Northwest

FIGURE 8. EIA/DOE REGIONS [9]

cooperation and net savings in capital investments between industry and utilities is substantial across the country and even greater in the eastern Atlantic coastal states.

COMPRESSED NATURAL GAS-FUELED VEHICLES [10]

Natural gas is an excellent fuel for use in internal combustion engines. Gasoline and diesel fuels have specific combustion characteristics requiring that engines be designed to match the fuel to give optimum performance: spark ignition (gasoline), high compression auto ignition (diesel). Natural gas, which has a high octane of approximately 130 (compared to 87 to 92 for no-lead gasoline) needs higher compression ratios (15/1) and spark ignition because it does not auto ignite as does diesel fuel. While dual fueled engines, both gasoline and diesel, can and have been built, the efficient use of natural gas vehicles requires dedicated vehicles.

All general-purpose vehicles need, in addition to their design and manufacturing infrastructure, an operational fuel supply system. In the United States, so long as reasonably priced gasoline exists, it is hard to imagine a set of conditions that would bring forth both the manufacturing infrastructure and a compressed natural gas fuel supply system in competition with the complex and highly competitive auto/truck manufacturing and fuel supply system. In other nations where the indigenous resource base is predominantly natural gas--Canada, New Zealand, Australia, Indonesia, and hypothetically, even Europe--an alternate mobile vehicle infrastructure could, and may, be a logical development. For the

United States, the most probable natural gas fueled vehicles market is for fleet vehicles: short-range intercity vehicles, such as taxis, delivery trucks, postal service, police vehicles, school buses, and government fleet vehicles. Some estimates of this potential market will be given.

NATURAL GAS FUELED VEHICLES

Mobile vehicles conventionally use storage systems at 2400 to 3000 psig for compressed natural gas (CNG) or liquified natural gas (LNG) stored as a cryogenic liquid at temperatures near the atmospheric boiling point of methane. Typical CNG steel storage cylinders are 10 $^1/2$" in diameter and 38" in length, weigh 110 lbs and store 320 ft^3 at 70 C (3.2 equivalent gallons gasoline). Weight reductions by a factor of two are possible with cylinders made of aluminum liners overlapped with glass fibers or Kevlar. Full development and DOT certification of such alternate cylinders has not occurred in the United States. Typical small vehicles use two or three cylinders giving an equivalent of 6 to 10 gallons of gasoline. Trucks usually have more potential storage space for cylinders and can carry more fuel.

For the CNG to be used in the engine, pressure reduction to about 1 psig is needed. Two stages of pressure reductions are normally used and the heat of expansion needs to be supplied to avoid regulator freeze-ups during operation. Safety requires overpressure protection of the cylinders and isolation of the passenger compartment from methane intrusion.

The engine has a high compression ratio (usually about 15/1), spark ignition, and requires a spark adjustment with speed to obtain optimum performance. Full optimization of natural gas fueled engines has not been achieved. Emission levels are lower from natural gas fueled engines and it may be a preferred fuel in congested city areas. Ford Motor Company, Caterpillar, and Cummings Engine all have developed prototype engines for natural gas operation. The engine design problems are manageable and only need a market to justify the development costs.

POTENTIAL U.S. MARKET

The logical near-term market for natural gas fueled vehicles is in fleets that can use a dedicated fuel supply system. The total number of fleet vehicles is large (see Table 8).

4×10^6 automobiles in fleets of 10 or more

3×10^6 trucks in fleets of 6 or more

Of these vehicles, the most promising potential applications are:

Utility Fleets

150,000 light vehicles (800-1000 gallons/yr/vehicle)

Government Fleets

600,000 autos

250,000 light trucks

Police Fleets

250,000 autos

Taxi Fleets

150,000 autos (3,000 gallons/yr/vehicle)

School Buses

400,000 buses (1,000 gallons/yr/vehicle)

Table 8. FLEET VEHICLE CHARACTERISTICS [10]

Vehicle Classification	Number of Vehicles, 1,000	Use Factor, 1,000 miles/year	Fuel consumption, miles/gallon	Daily use, miles
Automobiles in fleets of 10 or more 1/				
Purchased	995	20	19	76
Leased	2192	28	19	107
Daily Rental	491	16	19	61
Federal Gov't.	107	13	18	50
State and local Gov't.	500	17	17	65
Police	253	25	12	97
Utilities	162	12	16	46
Taxis	155	40	14	153
TOTAL	4855			
Commercial Trucks in fleets of 6 or more				
Pick-up	956	14.5	14.4	56
Panel	464	14.7	14.4	56
Walk-in	122	14.7	11.4	56
Other single unit	1096	13.0	6.0	48
Truck-tractor	546 (75% diesel)		3.9	60
TOTAL	3184			
Government Truck fleets				
8500 lb. GVW	243	7.7	10.0	29
Other	54	7.0	7.0	30
TOTAL	297			
Buses				
Transit	53	3.1	3.8	118
Intercity	20	54.0	6.0	206
School	399	7.5	7.4	29
TOTAL	472			

1/ Estimated data for 1981.

Source: 1977 Census of Transportation, Truck Inventory and Use Survey, U. S. Department of Commerce, Report No. TC 77-7-52.

A typical conversion factor (clearly engine specific) for natural gas-to-gasoline is 125 ft^3 natural gas $\simeq$ 1 gallon of gasoline. Thus, if the average gasoline consumption per vehicle is 1000 gallons per year, it would require 8 x 10^6 vehicles to create 1 trillion ft^3 of natural gas demand. There are about 2 x 10^6 vehicles in the fleets listed above; thus, an optimistic upper bound for natural gas consumed in fleet vehicles is approximately 250 billion ft^3 of natural gas annually. While this is a significant demand, the only way for natural gas demand in automobile usage to become a large factor is to have a significant portion of the personal automobiles in the United States natural gas fueled. This would require a national compressed natural gas fuel supply system. While technically such a system is feasible, it seems highly doubtful that it will occur in the near future, particularly if gasoline remains widely available at reasonable prices.

CONCLUSIONS

The major potential for new natural gas demand comes from the generation of electricity: gas turbine combined cycle systems for electric utilities and cogeneration systems for energy-intensive industry. The combined demand could realistically be between 3 and 5 Tcf per year with an upper bound of as much as 10 Tcf per year. The potential demand from other applications of new or improved technology is substantially less. Compressed natural gas fueled vehicles might produce $^1/4$ Tcf. The additional demand from natural gas heat pumps and air conditioning systems for commercial and residential systems have a lower probability. For air conditioning systems the electric system has a major cost and performance advantage. For those heating systems where natural gas would normally be used, the new technology will give improved operational efficiency and tend to reduce demand. Overall the potential for new natural gas demand lies predominantly with the production of electricity.

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APPENDIX A

NATURAL GAS FIRED COMBINED CYCLE GENERATORS: DOMINANT SOLUTIONS IN CAPACITY PLANNING[1]

by

Richard Tabors

Daniel P. Flagg

SUMMARY

In this study, natural gas fired, gas turbine combined cycle generators (GTCC) are evaluated as alternatives to more conventional base and intermediate load generators using the Electric Power Research Institute (EPRI) funding capacity planning framework, EGEAS. The study is based on analysis of the six EPRI regional utilities whose current capacity mix reflects the capital stock of the U.S. utility regions. The analysis compared 18 generation alternatives over a 15-year planning horizon utilizing a dynamic programming optimization algorithm to select the optimal path in each region. Sets of sensitivity analyses were carried out to evaluate the optimal path relative to a series of near optimal paths and relative to changes in the fuel and economic assumptions in the analysis. A second set of analyses were carried out to evaluate, for the EPRI Northeast region, the level of financial regret associated with capacity expansion decisions based on assumptions that later proved to be incorrect.

The results of the study indicate that the natural gas fired combined cycle systems (currently 47% and advanced 55% efficient technologies) dominate the investment alternatives. In two regions, the Northeast and the Southeast, these technologies are chosen over all over alternatives throughout the planning horizon. Even in those regions of the United States in which there is

significant coal available at reasonable cost, the CTCC's are a portion of the optimal capacity expansion path.

Sensitivity analyses show that over a range of gas costs relative to oil and coal of 25%, gas turbine combined cycle systems remain competitive. Increases in the relative prices of oil and/or coal lead to greater economic advantage from the GTCC systems. The capital versus operating cost tradeoff between GTCC and nuclear plants showed the GTCC to be the better alternative. Evaluation of the financial regret associated with investment decisions based on assumptions that later proved incorrect again showed that the GTCC technology offered small risk for the utility.

The analyses also evaluated the potential for increased efficiency GTCC systems (from 47% to 55%), which are under development by M.I.T. and General Electric under EPRI funding. This higher-cost High Efficiency system (HECC) also dominated the coal, oil, and nuclear options in the capacity planning analyses.

ABSTRACT

Natural gas fired gas turbine combined cycle technologies are evaluated in a standard capacity planning model for the six EPRI Regional Utilities. Results indicate that GTCC technology dominates the optimal decision paths for 4 of the 6 regions studied. Further, the study concludes that the GTCC options offer minimal downside risk on price of gas, on operating conditions, or on capital cost.

BACKGROUND AND INTRODUCTION

Natural gas fired combined cycle systems have been used successfully in a number of U.S. utilities and extensively in oil exporting countries of the

Middle East. The current provisions of the Fuel Use Act (PL 95-620) do not allow for natural gas in utility generators. The rationale for this decision is now under challenge as it appears that supplies of natural gas are sufficient for extended consumption in the United States. Further, natural gas now appears to be a necessary alternative for the utility industry as the United States looks for environmentally clean and safe generating systems. In addition, the GTCC technologies represent systems that are easily sited, are supplied by domestic rather than imported fuel, and are far less subject to labor problems in fuel supply.

The purpose of this research was to evaluate the potential for GTCC technology in optimal capacity planning structures in the United States. The analytic system used for this analysis was the newly released Electric Generation Expansion Analysis System (EGEAS) developed by M.I.T. and Stone and Webster Engineering Corporation for EPRI[2]. The EGEAS structure allows optimal planning analyses using one of three optimization structures: Linear Programming, Dynamic Programming, and/or Generalized Benders' Decomposition. The planning horizon can be adjusted by the analyst as can a post-plan extension period for cleaning up and effects. In addition, the structure allows for sensitivity studies given an optimal or prespecified expansion pathway. This analysis utilized the Dynamic Programming structure of EGEAS and made extensive use of the prespecified pathway analytical capability in carrying out sensitivity and economic regret studies.

In order to evaluate the GTCC technology within a range of utility environments, the authors used the EPRI-developed Regional Utility Systems. The Regional Utility Systems provide scaled-down models of existing capacity and load duration curves as well as fuel price regimes for each of six national regions.[3,4] Figure 1 and Table 1 summarize the characteristics of each of the

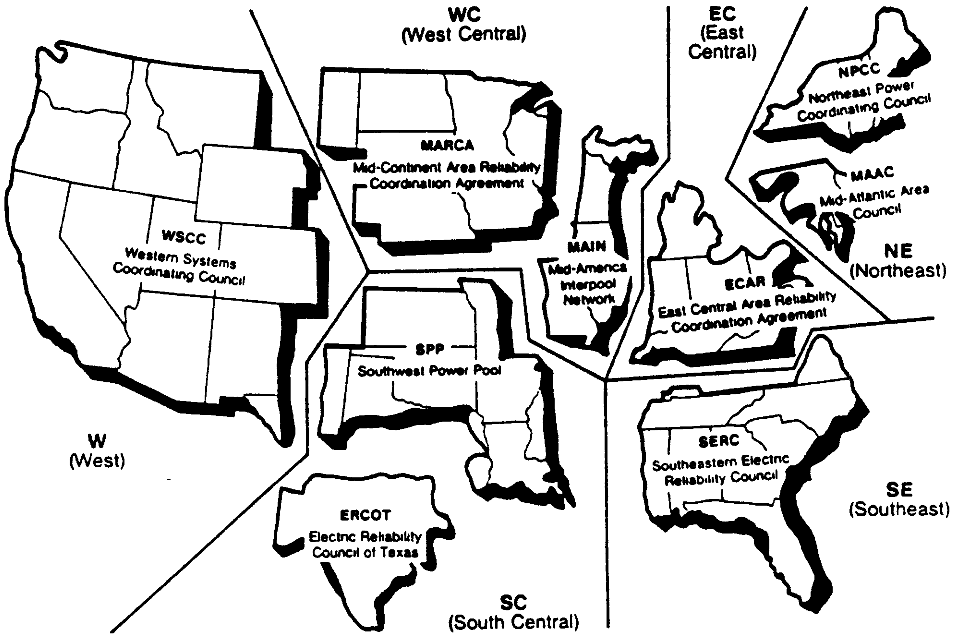

Figure 1. EPRI Regional Systems. Six Regions Based on National Electric Reliability Council Regions (contiguous U.S.).

Table 1

REGIONAL UTILITY CHARACTERISTICS (%)

Region	Hydr	Nucl	Coal	Oil & Gas	Ct	Growth Rate	Res Marg	Scale Factor
NE	10	21	21	36	12	2.1	36	5.74
SE	8	14	46	12	10	3.7	29	7.90
EC	0	12	76	4	8	3.5	33	5.79
SC	1	10	41	46	2	4.2	20	6.70
WC	3	22	59	8	8	3.2	19	4.34
W	33	13	29	19	6	3.5	35	7.04

six regions. The Regional Utilities have been developed such that results of analyses carried out for the model regions may be "expanded" to reflect actual national or regional imports by multiplying by the scale factor indicated in Table 1. With the exception of the final discussion, all numbers quoted in the text and in the tables reflect the model utilities.

The published regional utilities were structured such that existing plant construction dates were in five-year intervals. In order to provide a more natural retirement schedule, the authors evenly spread the in-service dates of plants built prior to the planning horizon.

The study was carried out for a 15-year planning horizon beginning January 1, 1990 and ending December 31, 2004. In order to eliminate end effects, EGEAS was run with a 20-year extension period beyond 2004.

Under joint funding from EPRI and General Electric, M.I.T. and General Electric's Gas Turbine Division are evaluating alternate designs that will allow for higher efficiencies in GTCC systems. A second objective of this study was to evaluate the impact that the development of such an improved technology could have capacity choices. In this analysis it is assumed that HECC a higher efficiency system (55% as opposed to 47%) will be available at a higher cost by 1995.

DATA BASE AND ASSUMPTIONS

Table 2 summarizes the alternatives considered after initial screening. Based on Screening Curve analysis within the EGEAS framework, only the most attractive five alternatives were considered in the optimal expansion analysis. These were a 1000 MW PWR, an 800 MW AFBC, a 250 MW GTCC, a 250 MW HECC, and a 100 MW CTOIL. In each region the GTCC appeared as one of the expansion alternatives. While the capital components do not vary regionally, the fuel

Table 2

GENERATION ALTERNATIVES CONSIDERED
IN FINAL DYNAMIC PROGRAMMING ANALYSES

Technology ($/MWh)	SIZE (MW)	Heat Rate (Btu/kWh)	1984$ Capital Costs ($/kW)	Operations Fixed	Var ($/kW-Yr)
Light Water Reactor	1000	10700	2090	8.90	1.70
Atmos. Fluid Bed Coal	800	9640	950	8.40	0.80
GTCC	250	7261	332	1.55	1.64
HECC	250	6205	475	2.50	3.00
CT Advanced	100	10300	250	0.40	3.20

costs vary, as does the mix of alternatives.

Table 3 summarizes the economic assumptions used in the analysis. Note that all costs and results in the study are reported in constant 1980$. The capital costs shown reflect 1984/85 reported costs for plants under construction or being completed, taken back to 1980$ at an annual inflation rate of 6%. Cost estimates for the HECC are based on rough cost estimates made at both General Electric and M.I.T. No detailed cost estimates have, as yet, been carried out. With the exception of natural gas, fuel and operating costs are derived from EPRI TAG.[5] The price of natural gas reflects the 1984/85 utility costs stated in 1980$. It was assumed that there was no real escalation in fuel costs. As will be seen later in this paper, the total costs of the individual plans are sensitive to assumed plant cost but the conclusions are sensitive only to large relative changes in the capital or operating costs.

DISCUSSION OF BASE CASE ANALYSES

Figures 2 through 6 provide a summary of the base case runs for each of the six utility regions in the United States. The upper line in each of the figures represents cumulative additions to capacity from 1990 to 2004. Additional capacity requirements are based on regional estimated growth rates (see Table 1) and upon plants currently committed being completed.

Given the assumptions stated above, Figures 2 and 3 show the expansion paths for both the Northeast and the Southeast in which only natural gas fired combined cycle systems are added to capacity over the length of the planning horizon. Table 4 presents the 15-year time stream of capacity additions for the Northeast. The model forecasts a total of 12,250 MW of combined cycles for the scaled regional utility. This expands to over 70,000 MW for the actual geographic region extending West through Indiana and South through Kentucky. Of

Table 3

ECONOMIC ASSUMPTIONS

All costs are quoted in 1980$
Discount rate 10%
Inflation 6%
No real escalation in any fuel cost
No nuclear available until 1995
No HECC available until 1995

Fuel Prices	$/MMBtu
Coal	2.60
Oil #2	8.15
Natural Gas	4.00
Nuclear	.85

Table 4

NORTHEAST BASE CASE: ANNUAL ADDITIONS

Year	Retirements	Nuc	AFBC	GTCC	HECC	Total Capacity
1990	800	0	0	1500	0	20500
1991	800	0	0	1000	0	20700
1992	100	0	0	500	0	21100
1993	600	0	0	250	0	20750
1994	600	0	0	500	0	20650
1995	600	0	0	0	1000	21050
1996	400	0	0	0	750	21400
1997	400	0	0	0	1000	22000
1998	400	0	0	0	750	22350
1999	300	0	0	0	750	22800
2000	1100	0	0	0	1250	22950
2001	300	0	0	0	500	23150
2002	900	0	0	0	500	22750
2003	200	0	0	0	500	23050
2004	1200	0	0	1250	250	23350
TOTAL	8700	0	0	5000	7250	23350

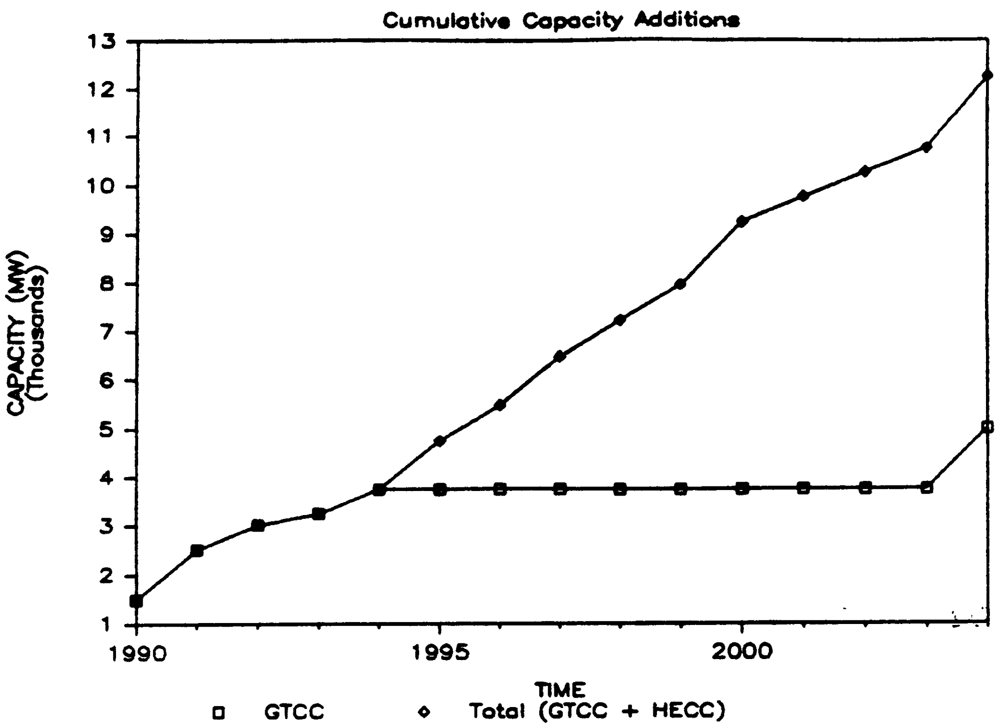

Figure 2. Northeast Base Case.

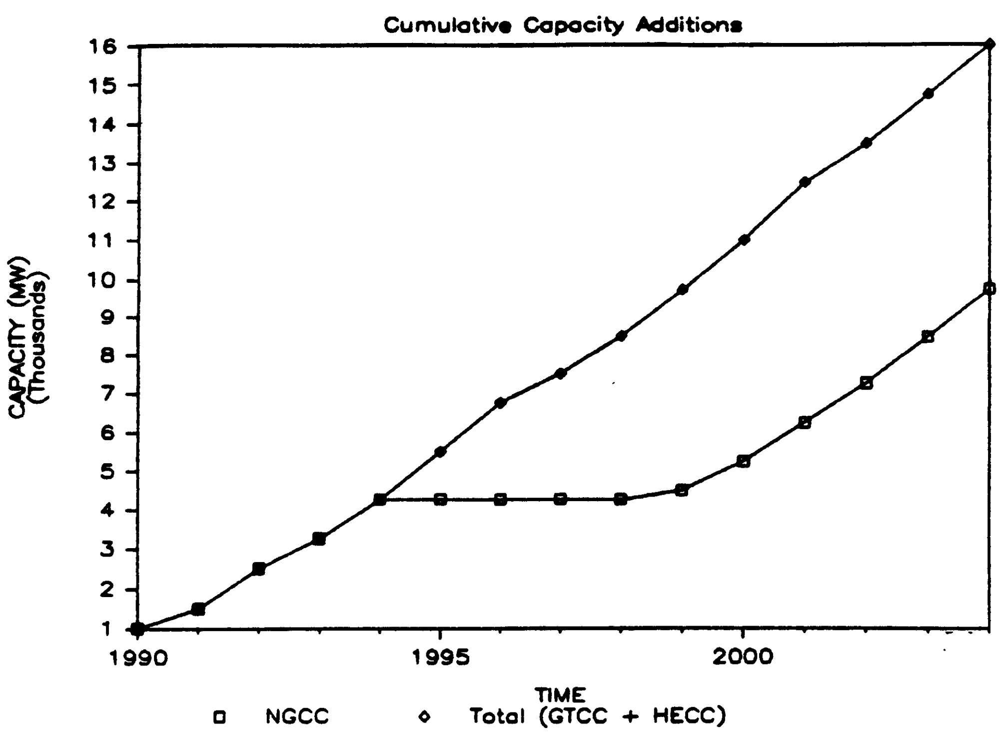

Figure 3. Southeast Base Case.

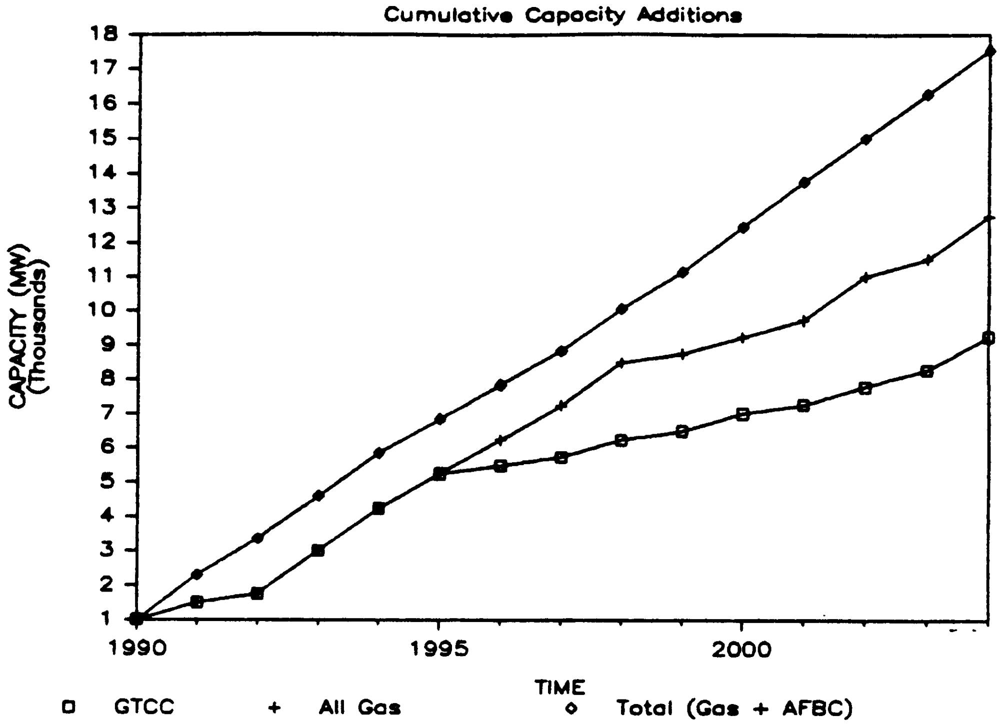

Figure 4. West Central Base Case.

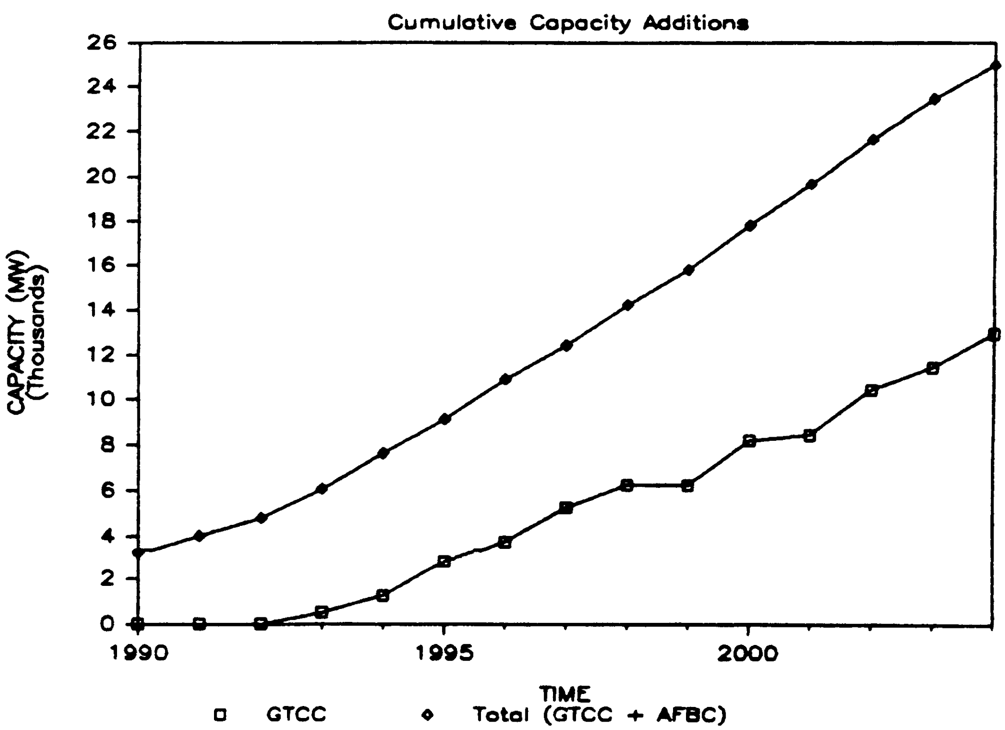

Figure 5. South Central Base Case.

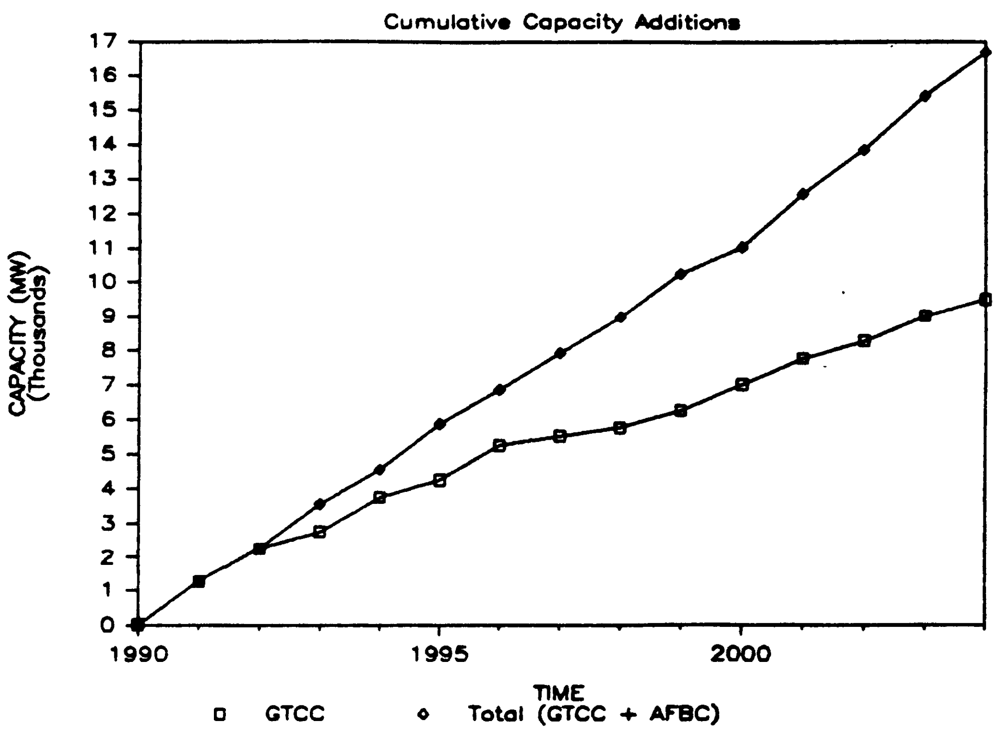

Figure 6. East Central Base Case.

this total, 70% is required to replace scheduled retirements.

Figure 4 shows the expansion path for the West Central region. In this case there is limited gas brought on line in both the early years and then in the later years of the planning horizon.

Figures 5 and 6 cover the South Central and the East Central regions. Both show a similar pattern: significant growth both in the natural gas based technologies as well as in the alternative, coal.

Figure 7, the West, shows a dramatically different picture. It is an extremely large and diverse region in which the generating capacity is one-third hydro. The uncertainty of the annual availability of this capacity has not been adequately modeled by the EPRI Regional Utilities, nor by the EGEAS data base used for this region. This uncertainty could only improve the attractiveness of the GTCC in this region. The availability of coal at lower cost than for other regions in the country would also tend to increase the attractiveness of coal-fired plants in the West. It is interesting to note the number of gas-fired GTCC systems, far in excess of model projections for the region, which are being installed as cogenerators in California alone.

SENSITIVITY STUDIES

A series of sensitivity studies was carried out for one of the regions studied, the Northeast. The Northeast was chosen because the base case solution, involving entirely natural gas fired combined cycle systems, was among the most dramatic of the six regions. Two types of sensitivity studies were carried out. The first involved rerunning the optimization algorithm with alternate assumptions concerning the costs of both capital and operations of the GTCC and HECC. The second set of analyses--discussed in the section that follows--evaluated, again for the Northeast, the economic regret, in total

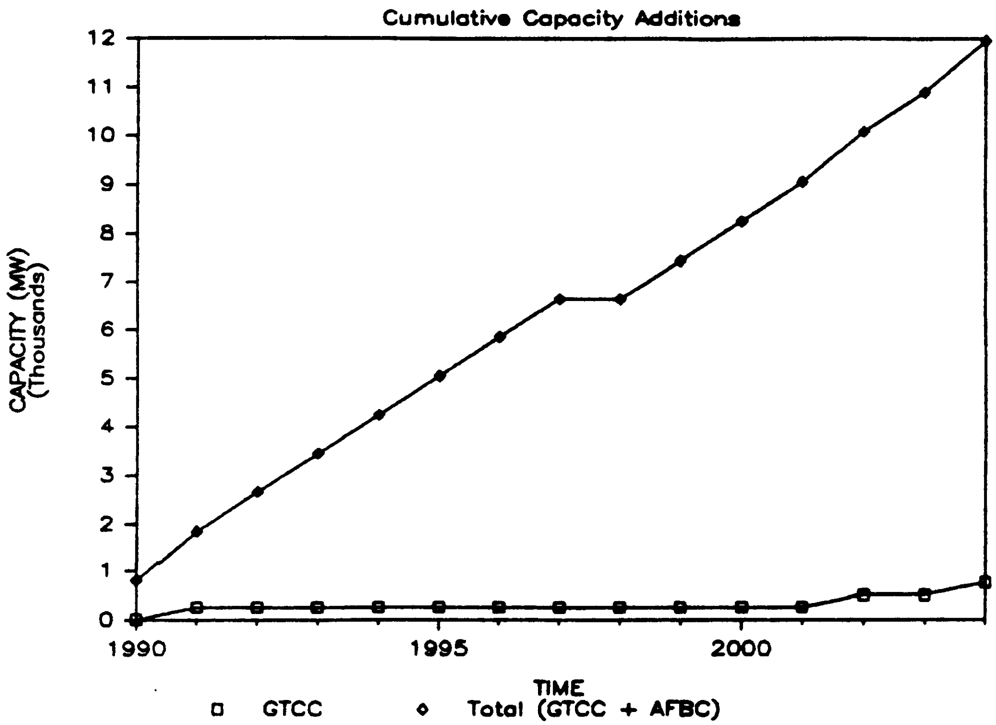

Figure 7. West Base Case.

system costs, associated with taking a course other than that involving the GTCC.

Figure 8 summarizes the change in capacity additions of GTCC units with an increase of 25% in natural gas prices, from $4 to $5 per MMBtu. For the Northeast the difference in capacity is made up from additional units of coal and nuclear. The principle difference occurs, even in this instance, in the first five years of the expansion analysis period. When the HECC is available in 1995, the natural gas options absorb the majority of the capacity expansion to 2004, accounting for all but 2.5 of the 8.5 MW of capacity expansion in the intervening time period.

The results of the sensitivity analyses using the full Dynamic Programming capabilities of EGEAS may be summarized as follows:

--The impact of decreased efficiency in the HECC system from 55% to 50%, first with all other assumptions remaining constant and second with the price of natural gas increased to $5/MMBtu. In the first instance the HECC are eliminated from the optimal set. The capacity required is made up by GTCC systems. In the second case there was a reduction in the number of combined cycle plants installed, the difference in capacity required being made up of new coal and nuclear capacity.

--The impact of an increase in load growth from 2.1% annum to 5% per annum. The increase in capacity requirements in 2004 was made up entirely from additional GTCC and HECC units in roughly the same proportion as was the case under the 2.1% growth path.

REGRET STUDIES

A set of economic regret studies was carried out and compared to the Northeast region base case. The analyses utilitized the Prespecified Pathway capabilities of the EGEAS model to calculate the net present value of all costs for the analytic period and the extension (numbers reported do not include the extension period) assuming one or more of the input assumptions were changed. Three separate scenarios were optimized. In each case an optimal system

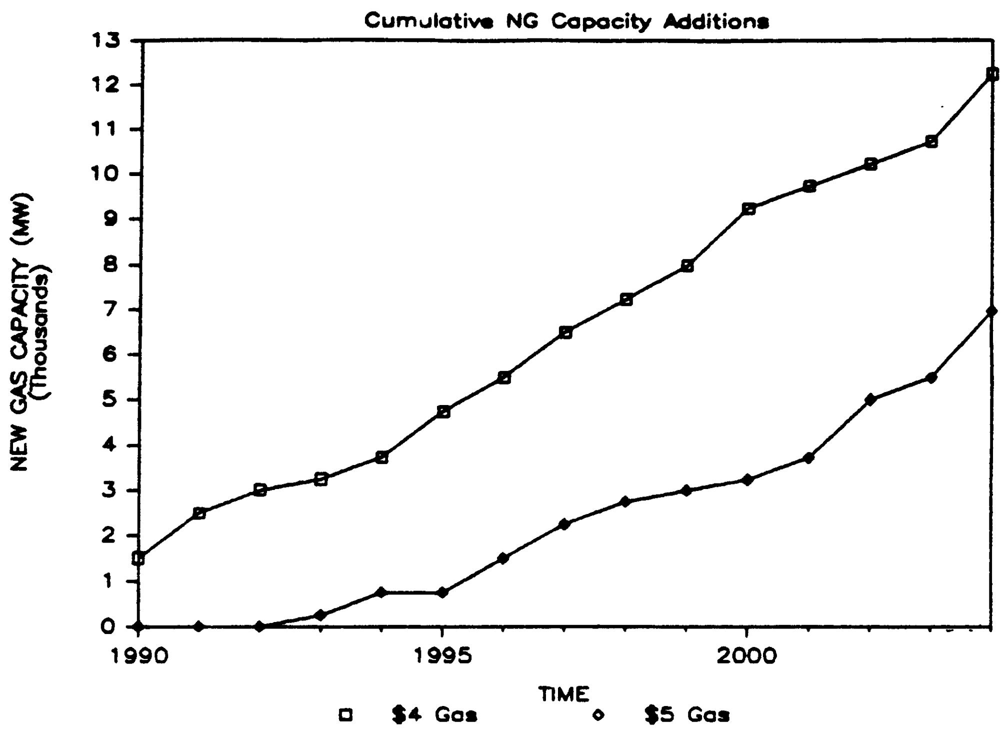

Figure 8. North East - $4 versus $5 Gas.

was specified and a net present value calculated. Then one or more of the initial parameters were changed and a new NPV calculation done on the same system with the new parameters. The change in NPV provides an indication of the financial regret involved of building a system based on assumptions that later proved incorrect.

Scenario 1 dealt only with the base case and changes in efficiency, price of natural gas, and capital costs of the HECC. Table 5 summarizes the results. The NPV of the base case is $11,530 million.

--If the system were committed and built based on the HECC at 55% efficiency but performed at 47% efficiency, i.e., the same as the GTCC, the increase in total cost over the predicted optimal would only be 2.63%.

--If the price of natural gas were incorrect by 50%, i.e., the cost were $6/MMBtu rather than $4/MMBtu, the increase in the cost of the plan would be 18%. On the other hand, if the price were lower by 25%, the cost of the plan would be 9% less.

--If the capital cost of the HECC were projected incorrectly low by 20%, the resulting increase in cost would be 1.4%.

The results of the regret analysis for this first scenario indicate that there is little regret associated with either change in heat rate or in capital cost (it would be anticipated that these are tightly correlated). Change in gas prices is important but only a 50% increase in cost can be said to have a major impact on the level of regret.

The second scenario (Table 6) is based on a more conservative approach to the construction of combined cycle plants, allowing for only two to be constructed each year. A Dynamic Programming analysis was carried out utilizing this "tunnel" constraint, thus requiring the additional capital to be made up of coal and nuclear plants. Compared with the optimal pathway given this constraint, the base case cost is 4.8% less. Having made this set of decisions, the impact of gas prices on the total costs of this plan is, as would be

Table 5

SCENARIO 1 REGRET ANAYLSIS FOR NORTHEAST

Variable	New Value	NPV ($Millions)	% Change
BASE CASE		11,530	
EFFICIENCY	55%	11,530	
	53	11,608	0.68
	51	11,690	1.39
	49	11,774	2.12
	47	11,833	2.63
GAS PRICE	$3	10.378	-9.99
	$4	11,530	
	$5	12,580	9.11
	$6	13,629	18.2
CAPITAL COST	-10%	11,455	-0.65
	BASE	11,530	
	+10%	11,606	0.66
	+20%	11,690	1.39

Table 6

SCENARIO 2 REGARD ANALYSIS FOR THE NORTHEAST

A LIMIT OF 2 GAS FIRED COMBINED CYCLES PER YEAR

Variable	Case	($Millions)	%Change
The Two Plant		12,112	0.00
Base Case		11,530	-4.81
Gas Price	$3	11,467	-5.33
	$4	12,112	0.00
	$5	12,597	4.00
	$6	13,083	8.02
Capital Cost	-10%	12,066	-0.38
	Base	12,112	0.00
	+10%	12,158	0.38
	+20%	12,208	0.79

expected, far less. A 50% change in gas prices produces only an 8% change is the solution.[6] The impact of changes in the capital cost of the gas plants in correspondingly lower as well.

The final set of regret functions evaluated were based on a scenario in which Combined Cycles were excluded from the set of capacity expansion alternatives (Table 7). The reference Dynamic Programming analysis was based on the capital cost of both nuclear and coal, as shown in Table 2. In this case the overall solution was inferior to the base case by 13%. If the fuel cost for coal were understated by 20%, the resultant cost would be 2.6% higher, roughly equivalent to the same percentage increase in the capital cost of the coal.

A second set of runs in this analysis utilized nuclear plant costs at $1300 (the TAG number) rather than at $2000. In this case the comparison with the base case showed it to be 5.9% inferior. Significantly, had the initial decision been based on the availability of lower cost nuclear capacity but the actual cost to completion been the higher, the impact on the cost of the plan would be a further increase of 12.5%. Finally, given this plan, an increase in coal costs of 20% would have an impact of only 1.7% in the total costs of the plan.

CONCLUSIONS

The results of this analysis are significant from three perspectives: from the perspective of capacity planning, from the perspective of governmental policy, and from the perspective of gas utilization.

Natural gas fired combined cycle systems offer an important alternative for capacity planning. In all regions they contributed to the optimal capacity mix. In three of the six regions they provided the majority or all of the optimal mix. The results of the regret analyses show clearly the cost implications of

Table 7

SCENARIO 3 REGRET ANALYSIS FOR THE NORTHEAST

NO NATURAL GAS FIRED COMBINED CYCLE PLANTS

Variable	($Millions)	%Change
No Gas Case	13,257	
Base Case	11,530	-13.03
Increase in Coal Fuel Cost by 20%	13,610	2.66
Increase in Capital Cost of Coal 20%	13,605	2.63
Low Cost Nuclear (TAG)	12,251	
Base Case	11,530	-5.89
Assumed Nuclear Increase in Capital	13,790	12.56
Coal of Coal 20%	12,461	1.71

now allowing for the natural gas fired combined cycle option. Further, these studies point clearly to the minimal downside risk associated with significant capacity investment in the GTCC technology.

Current governmental policy does not allow for natural gas to be used in new power generation. This decision was based on what now appears to be faulty assumptions concerning gas availability and clearly on faulty assumptions concerning fuel economics. Further, Table 8 indicates the projected total increase in natural gas consumption (scaled to the U.S.) required to supply the optimal capacity expansion plans defined in this analysis. It is striking to note that relative to the DOE/EIA projections, which assume no new gas capacity, the projections presented in this paper reflect only an increase from 4×10^{12} to 7.8×10^{12} SCF or less than a doubling in utility gas consumption. In terms of the total projected consumption of natural gas in the United States, in all sectors, this would reflect only an increase of 20% over 1995 levels.[7]

Finally, this analysis points to the significant market potential for both the combined cycle technologies and for natural gas firing. Further, the results lead logically to the next question: Would these systems not be even more cost effective in an industrial/utility interaction, i.e., either as cogeneration under PURPA (the California model) or, conceivably, as deregulated energy suppliers to the U.S. utility industry?

This preliminary work has given rise to several interesting results with far-reaching policy implications. Gas fired combined cycle systems may prove to be a real answer to problems being faced by the electric power industry. Their economic competitiveness cannot be denied. Their environmental and safety superiority, their ease of siting and modularity make them ideal systems for utility expansion in an uncertain planning environment. The next steps include modification of the Fuel Use Act and more detailed analyses of individual utility systems.

Table 8

TOTAL INCREMENTAL GAS CONSUMPTION BY REGION
(1×10^9 SCF)

Region	1990	1994	1999	2004	10^3 MW	Total
NE	419	1039	1688	2411	12	12
SE	79	711	1904	3350	16	16
EC	0	226	359	643	9	16.5
SC	375	281	342	643	13	25
WC	26	126	395	707	9	17.5
W	0	63	14	21	15	12
TOTAL	899	2450	4700	7780		

NOTE: These values reflect the actual regions, not the model regions.

FOOTNOTES

1. The research reported in this appendix is a portion of the activities of the Integrated Energy Systems consortium coordinated at M.I.T.

2. Massachusetts Institute of Technology and Stone and Webster Engineering Corporation, The Electric Generation Expansion Analysis System (EGEAS), (EPRI, Palo Alto, California) RP1529, EPRI EL-2561, August 1982.

3. EPRI, The Regional Utility Systems, EPRI Special Report (EPRI, Palo Alto, California), EPRI P-1950-SR, July 1981.

4. The price of natural gas used in the analysis was based on 1984/85 gas prices. Note that extensive sensitivity analyses were carried out on this variable.

5. EPRI, TAG Technology Assessment Guide, EPRI Special Report (EPRI, Palo Alto, California), EPRI P-2410-SR, May 1982.

6. It must be noted, however, that this case is nearly 5% inferior to the original base case.

7. Department of Energy, Energy Information Agency, Annual Energy Outlook 1983 with Projections to 1995, (U.S. DOE/EIA, Washington, D.C.), DOE/EIA-0383(83), May 1984.