SENATE OF CANADA

NATURAL GAS DEREGULATION AND MARKETING

Twelfth Report

Standing Senate Committee on
Energy and Natural Resources

September 1988

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Natural gas deregulation.

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Second Session
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SENATE OF CANADA

Proceedings of the Standing Senate Committee on

Energy and Natural Resources

Chairman:
The Honourable EARL A. HASTINGS

Wednesday, September 7, 1988

Issue No. 24

Sixth Proceedings on:

Examination of the production and use of natural gas in Canada, with particular reference to natural gas deregulation.

TWELFTH REPORT OF THE COMMITTEE

Deuxième session de la
trente-troisième législature 1986-1987-1988

SÉNAT DU CANADA

Délibérations du Comité sénatorial permanent de

L'énergie et des ressources naturelles

Président:
L'honorable EARL A. HASTINGS

Le mercredi 7 septembre 1988

Fascicule nº 24

Sixième fascicule concernant:

Étude de la production et l'utilisation du gaz naturel au Canada et en particulier la déréglementation du gaz naturel

DOUZIÈME RAPPORT DU COMITÉ

MEMBERSHIP OF THE COMMITTEE

The Honourable Earl A. Hastings, *Chairman*

The Honourable R. James Balfour, *Deputy Chairman*

and

The Honourable Senators:

Adams
Barootes
Bélisle
Bielish
Hays
Kenny
Lefebvre
* MacEachen, P.C. (or Frith)
Marshall
* Murray, P.C. (or Doody)
Olson, P.C.
Stewart *(Antigonish-Guysborough)*

* *Ex officio* Members

Note: The Honourable Senators Bazin, Fairbairn, Marchand, P.C., Ottenheimer and Roblin, P.C., also served on the Committee at various stages.

Research Staff:

Dean N. Clay, Energy Consultant
Lawrence A. Harris, Economics Consultant

André Reny

Acting Clerk

Timothy Ross Wilson

Clerk of the Committee

ORDERS OF REFERENCE

Extract from the *Minutes of the Proceedings of the Senate*, Wednesday, April 1, 1987:

Pursuant to the Order of the Day, the Senate resumed the debate on the motion of the Honourable Senator Hastings, seconded by the Honourable Senator Petten:

That the Standing Senate Committee on Energy and Natural Resources be authorized to examine the production and use of natural gas in Canada, with particular reference to natural gas deregulation, or any matter relating thereto; and

That the Committee present its report no later than 31st March, 1988.

After debate, and—
The question being put on the motion, it was—
Resolved in the affirmative.

Extract from the *Minutes of the Proceedings of the Senate*, Tuesday, March 22, 1988:

The Honourable Senator Petten for the Honourable Senator Hastings moved, seconded by the Honourable Senator Argue, P.C.:

That, notwithstanding the Order of the Senate adopted on Wednesday, 1st April 1987, the Standing Senator Committee on Energy and Natural Resources, which was authorized to examine the production and use of natural gas in Canada with particular reference to natural gas deregulation, be empowered to present its report no later than Wednesday, 21st December 1988.

After debate, and—
The question being put on the motion, it was—
Resolved in the affirmative.

Extract from the *Minutes of the Proceedings of the Senate*, Tuesday, july 5, 1988:

With leave of the Senate,
The Honourable Senator Balfour moved, seconded by the Honourable Senator Rossiter:

That, in the event of an adjournment of the Senate which exceeds one week, the Standing Senate Committee on Energy and Natural Resources be authorized to publish and distribute its Ninth Report (interim) on the examination of the production and use of natural gas in canada, wiith particular reference to natural gas deregulation, or any matter relating thereto, as soon as it becomes available; and

That, in the event of a prorogation of Parliament, the Honourable Senators authorized to act for and on behalf of the Senate in all matters relating to the internal economy of the Senate during any period between sessions of Parliament or between Parliaments, be authorized to publish and distribute the above-mentioned interim report.

After debate, and—
The question being put on the motion, it was—
Resolved in the affirmative.

Charles A. Lussier
Clerk of the Senate

REPORT OF THE COMMITTEE

The Standing Senate Committee on Energy and Natural Resources has the honour to present its

Twelfth Report

Your Committee, which was authorized to examine the production and use of natural gas in Canada with particular reference to natural gas deregulation, has, in obedience to the Orders of Reference of 1st April 1987, 22nd March and 5th July 1988, proceeded to that inquiry and now presents its report.

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Executive Summary

Natural gas, once an incidental aspect of oil production, has become a premium fuel today. In Canada, natural gas accounts for one-quarter of the domestic demand for primary energy and that share has been expanding. Of all of the fossil fuels, natural gas has the least harmful environmental impact, and its non-fuel use in fertilizer and petrochemical production is increasing.

Until the 1950s, gas was at best a local fuel. At worst, it was a nuisance in the production of oil. The first conservation measures for natural gas recognized its value as a source of reservoir pressure to improve oil recovery. Until the 1960s, gas was routinely flared during oil production because it lacked commodity value.

As natural gas reserves grew in the 1950s, Alberta allowed gas sales to other provinces and into the United States. Production expanded dramatically and by 1973 Canada was exporting gas to the U.S. at an annual rate more than 100 times that of 1952. In 1988, Canadian natural gas is a key source of domestic energy, a vital petrochemical building block and a major export commodity.

Natural gas satisfies about 25% of domestic energy demand and more than one-third of Canadian production is sold into the U.S. market. It is also the basis of a world-scale petrochemical industry centred in Alberta and Ontario.

The importance of natural gas will continue to increase into the 21st century. It is more environmentally acceptable than either oil or coal as a hydrocarbon fuel. Gas has almost three times the reserve life in Canada today of conventional crude oil, and remaining undiscovered reserves of natural gas are considered to be substantially larger than those of conventional oil.

In both Canada and the United States, there has been a dramatic change in natural gas markets in the 1980s. The two countries have abandoned their highly regulated systems, which were for many years characterized by mandated prices and pipeline tariffs, inflexible contracting practices and government intervention in all aspects of the market. Today, gas prices are deregulated and determined in the marketplace in transactions between buyer and seller. Natural gas competes vigorously with alternative fuels – and in some instances with itself. Pipeline tariffs remain regulated insofar as the transportation function is concerned because many pipelines have natural monopolies.

Although Canada started the process of deregulation later than did the United States, it has proceeded more rapidly and more smoothly here than in the U.S. In part this reflects the larger and more complex U.S. gas market and in part it reflects the enormously complicated American system of regulation put in place in the 1970s.

Natural gas faces unique transportation constraints that restrict its market focus to continental regions, unlike oil which moves freely around the globe. A successful gas market requires security of supply for the consumer, a viable pipeline transportation and distribution system, and a healthy production sector. Not surprisingly, a complex regulatory system had evolved to protect these interests since Ontario first halted U.S. gas exports in 1907.

The modern regulatory system has its roots in the 1950s. At the provincial level, Alberta consumers were protected from the depletion of what was to become their most important source of energy. At the federal level, the National Energy Board developed regulatory procedures to protect consumers in gas-importing provinces, as the U.S. appetite for Western Canadian gas grew through the 1960s and into the 1970s. It was also necessary to assure the financial and operational stability of trunk pipelines serving the interprovincial and international markets. In regulatory terms, the marketing of natural gas came to be treated as a public utility.

The first oil price shock of 1973-74 also increased the price of natural gas. In response, the regulatory system was extended to include price controls on gas. The Iranian Revolution followed by the opening of the Iran-Iraq war, with the associated oil price shock of 1979-80, made consumers more aware of the vulnerability of internationally traded energy commodities. In turn, this provided a broad, political consensus for regulatory measures aimed at ensuring the security of energy supplies.

High oil and gas prices were not sustained in the 1980s. Prices slumped in the early 1980s as energy conservation, oil substitution, new non-OPEC oil production and a severe recession combined to erode OPEC's market position. In 1986, the price of oil collapsed in a glutted market, throwing the petroleum exploration and development sector into financial disarray.

Part of the public policy solution to restore health to the petroleum industry was market deregulation. Public acceptance of (or perhaps indifference to) the new policy direction reflected lower oil and gas prices and the perception that the consumer was no longer vulnerable to events in the international energy market.

Deregulation has proceeded on an approximately parallel course in Canada and the United States. The energy provisions of the Free Trade Agreement reflect this evolution and are, in this sense, an unsurprising outcome. The provisions also reflect a desire on the part of the United States to remove some of the uncertainty from its energy situation.

Since the federal government and the producing provinces signed the Western Accord in March 1985, natural gas deregulation has developed three main thrusts:

(1) price is set between buyer and seller in private negotiations, not by government;

(2) producers and consumers have direct access to each other, and are less bound by relationships to large buyers and sellers at the transportation and distribution stages; and

(3) Canadian exporters have freer access to the U.S. market.

The transition to a deregulated market has not proved, however, to be as easily accomplished as some had anticipated. Alberta, for example, opposes the short-term direct sale of its gas to core market buyers, on the grounds that this is harmful to the longer-run interests of the producer, the consumer and the province. Indeed, a deregulated market may prove in some respects to be a more complex arrangement than a regulated market. The transition has been impeded by the price collapse of 1986, which badly hurt producers and made them more uncertain of the benefits of deregulation.

It is apparent to the Committee that deregulation faces limitations – it is not in itself an energy policy, merely one element of energy policy. Deregulation is a workable, national policy to the extent that it is supported by a broad political consensus embracing producers, consumers and the marketplace itself.

Perhaps the greatest impediment to deregulation has been the perception by many that the benefits of deregulation are not being equitably distributed. This perception of inequity has led both producing and consuming interests to have the system re-regulated to protect their traditional interests and bargaining positions.

This leads the Committee to conclude that deregulation is not a complete public policy prescription for natural gas marketing. There are practical limits to deregulation in at least three areas:

(1) the energy security of the consumer;

(2) the financial viability of the transportation and distribution system; and

(3) the economic and operational stability of the exploration, development and production sector.

The Committee endorses the principle that market forces must be allowed to drive the day-to-day workings of the marketplace. It realizes that the hand of the regulator must be applied sparingly, and only to satisfy fundamental public and national interests.

The regulatory system does have a continuing role to play, however, in protecting the long-term interests of the producer, transporter, distributor and consumer when it is evident that the free operation of a complex and highly specialized commodity market is unable to do so. Although natural gas is an abundant energy resource, it is nonrenewable and finite. The Committee recognizes the role of the regulator in ensuring a smooth evolution in Canada's energy economy and managing its long-term change as energy sources rise and fall in importance and as financial circumstances alter.

Two aspects of the transition to a deregulated gas market have been particularly controversial: the rules which will apply for domestic gas contracts, and the rules for admission of Canadian gas into the U.S. market. Efforts are being made in the domestic market to establish a new set of commercial rules for gas trading; public policy-makers have a parallel responsibility to address the long-term public interest in gas marketing.

The Committee makes the following observations regarding the Canadian gas market.

- Over the last three years, Canada has made a substantial achievement in moving from a highly regulated market to a free and responsible market. The Committee supports this initiative of freeing oil and gas markets from heavily administered arrangements.

- Canadian public policy should nevertheless recognize the legitimate, long-term role of providing energy security to consumers and stability to producers, transporters and distributors when market forces are unable to do so.

- Long-term supply commitments secured by contracts should be the basis for protecting the interests of all participants in the natural gas market.

To protect these interests and to help resolve one of the contentious issues in today's domestic gas market, the Committee advises:

- That the core market of gas consumers who lack fuel switching capability or access to other readily available energy supplies be protected by supply contracts no less than 10 years in length;

- That those supply contracts be evergreened and contain equitable price adjustment and price arbitration provisions;

- That the National Energy Board oversee the system of long-term core-market contracting; and

- That short-term direct sales to consumers in the core market be prohibited.

The Committee believes that its analysis, advice and recommendations provide a sound policy position from which it can fairly evaluate the merits of the Canada-U.S. Free Trade Agreement.

Policy Statement on the Core Market

The Committee endorses the policy initiative of freeing oil and gas markets from heavily administered arrangements. There remains a legitimate role for regulation, however, which includes providing for the long-term stability of energy supply where market forces do not appear to be doing so, or in the event of sudden major price disruptions in international petroleum markets.

What is important to the public interest is ensuring natural gas supplies are secured to provide for the needs of the Canadian market many years into the future, especially for consumers who have little or no potential to switch to alternative fuels. This requires holding sufficient gas in reserve to meet their future needs. A long-term financial commitment is required of all involved. Because the consuming market needs assured long-term supplies, that market should undertake to enter into agreements necessary to bring this about.

This can be accomplished in a market environment if consumers sign long-term contracts for gas supplies, with price to be adjusted periodically as the parties agree. Producers would be assured of the cash flow to continue exploring for and developing new reserves of natural gas that will maintain security of supply. These new reserves may also necessitate expansion of the gas transmission system, which requires secure contracts to obtain long-term financing.

If contract price negotiations deadlock, the parties should have recourse to an arbitration process to resolve the difficulties. The Committee sees this approach as preferable to other methods of price administration because, in normal circumstances, the interests of both parties can be accommodated without recourse to regulation.

Consumers with limited or no fuel-switching capability should be protected by long-term supply arrangements. They could accomplish this either as customers of local distribution companies or by entering into long-term direct purchase agreements. This group has come to be referred to, though without precise definition, as the "core market". Gas consumed for non-fuel uses such as fertilizer and petrochemical production should be exempted.

Unlike oil, natural gas cannot be purchased outside the country in significant quantities if Canadian deliveries are inadequate. It is essential to the Committee that the conditions be met for a secure supply of natural gas. Long-term gas purchase commitments are an effective means of ensuring this.

To ensure that the provinces have compatible positions, the National Energy Board (NEB) should rule on whether short-term direct sales may be allowed in particular cases.

(1) The Committee recommends that the National Energy Board oversee interprovincial core market transactions. The Board should conduct hearings to determine what constitutes the Canadian core market; to formulate rules regarding the availability of transportation service; and to determine how the Board would regulate core market transactions.

Local distribution companies should be obliged to contract for gas on a long-term basis to cover their core market demand. As the core market grows, contracts would be arranged to cover that growth. Existing contracts with take-or-pay obligations should be respected.

Core market consumers entering into direct sales should be required to sign long-term contracts. Consumers wishing to keep open the option of installing fuel-switching capability or of changing to a new fuel in the future can remain customers of the local distribution company, which will supply gas as required without need of a contract with the customer.

(2) The Committee recommends that the Canadian core market be served through long-term, evergreened gas contracts, and that these long-term commitments be for a minimum period of 10 years. Core customers should be allowed to make direct purchases of natural gas, provided that these purchases are also arranged through similar contracts.

It is evident that there will be increasing competition among domestic and U.S. buyers for Canadian gas supplies in the 1990s. Requiring the core market to contract for its gas consumption at least 10 years into the future through evergreened arrangements ensures that gas needed to satisfy the Canadian core market will not be committed to other markets. Canadian producers would have the security of long-term sales and Canadian core market consumers would have security of supply.

The Committee recognizes that long-term contracts in today's uncertain market will contain price review mechanisms. The Committee believes that the buyer and seller should be free to negotiate the initial contract price and any mechanism by which that price might be subsequently adjusted. These contracts are to be reviewable by the NEB.

This proposal does not constitute a supply test but rather a supply commitment secured by contract. The supply tests administered by the National Energy Board required that certain quantities of gas be withheld from the export market in anticipation of future sales in Canada. In the Committee's proposal, the buyer commits to take the gas supplies that have been dedicated through the long-term contract.

Canadian Gas Policy Issues

Introduction

One of the most contentious issues in Canadian natural gas deregulation is turning out to be the markets into which direct sales of natural gas may be made. This has come to be known as the "core market issue". The 31 October 1985 Agreement among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices gave buyers the opportunity to negotiate a gas purchase directly with producers, rather than obtaining their supplies through Western Gas Marketing Ltd. (WGML), the marketing subsidiary of TransCanada PipeLines Limited (TCPL).(1)

This was not a policy to abrograte existing long-term contracts which had been signed by producers and TCPL for what is referred to as "system gas". Rather, the new policy was meant to broaden the scope of market transactions, which could be used by those buyers whose needs were in excess of existing contracted supplies, or those who might not have been party to a long-term contract. Mainly, this group was envisaged to consist of industrial users who typically have shorter-term fuel contracts and fuel-switching capability. Under such arrangements, these buyers could become incremental users who would increase the demand for Western Canadian gas and hence the revenues to Western producers and producing-province governments.

Because of the strained financial position of many producers, who were short on cash flow, the new provisions offered a means of augmenting their income by selling gas that would otherwise be shut in. Actually, even some contracted system gas not taken by WGML can be and is being sold in direct transactions. Because a TOPGAS premium is levied on system gas to pay the banking consortium which refinanced the take-or-pay gas arrangements between TCPL and Western producers, shut-in contract gas which is released for direct sales also has a TOPGAS charge levied upon it, though at a lower rate.

The direct purchase provisions serve consumers well, by giving flexibility where it did not before exist and by realizing transactions at lower than existing contract prices. These benefits, however, are accessible to a wider group than industrial users.

Since the original Agreement does not preclude other types of consumers from completing direct purchase transactions, consumers tied into long-term contracts are endeavouring to replace their system gas requirements with direct purchases in order to realize a saving that is definite and easy to arrange. The consumer group which has traditionally purchased gas from local distribution companies (LDCs) that in turn contract for system gas consists mainly of non-industrial users who rely on gas as their only reasonable fuel alternative. This group of consumers is roughly defined as the "core market".

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(1) Western Gas Marketing Ltd. was established in December 1985 as a wholly-owned subsidiary of TransCanada PipeLines Limited. TCPL's supply of system gas is contracted from more than 700 Western Canadian producers in some 2,700 purchase agreements administered by Western Gas Marketing, which also administers sales contracts with other pipeline companies and distribution companies in Canada. WGML is active in the U.S. export market too, negotiating sales with interstate pipeline companies, local distribution companies and industrial gas users.

The efforts by Ontario and Quebec consumers to replace system gas with direct purchases place the brokerage division of TCPL – Western Gas Marketing Limited – in a difficult position. WGML is already unable to take all of its contracted gas, and losing Eastern consumers to the direct sales market only prolongs the TOPGAS and contractual difficulties. Furthermore, TCPL is obliged to provide pipeline access to third party gas – which it is doing without hesitation, according to the company. This may become problematic, because TCPL and local distributors of natural gas must, if not by contract then by good business planning, ensure that capacity on the pipeline is always available should fuller amounts of contracted system gas be demanded in the East.

As long as direct sales are viewed as incremental transactions, there is no policy problem. Saskatchewan takes this point of view. If, however, direct transactions are perceived to be eroding the established base demand for contract gas (at higher contract prices), there may be a policy dilemma at the provincial level. On the one hand, producers' interests are served by increasing their cash flow, even if the selling price is somewhat below existing contract levels. On the other, as the gas is leaving the province at lower prices, royalty revenues to the resource owner – the provincial government – are dropping. Thus provincial revenues are being lowered even when demand is steady or (to some extent) increasing. This poses a serious policy problem for the provincial government because the effects experienced are not tied to the robustness of the market, but rather to the technicalities of a freer trading environment.

Alberta has taken the position that the demand and revenue base represented by the pre-Agreement long-term contract arrangements must not be eroded, save for a weakening in actual natural gas demand (which would be reflected in lower takes by WGML, as is possible within the contracts). To this end, it has moved to block direct sales to this base demand or "core market".

Direct Purchase Issue

An important milestone of deregulation was the introduction of buy-sell agreements which enable gas users to contract directly with gas producers. Current prices in direct purchase transactions are below TCPL contract prices for system gas, and thus provide users with an incentive to refuse TCPL gas if it is possible to purchase directly.

Cash-starved western gas producers welcome the opportunity to make incremental sales through buy-sell arrangements. Concern has arisen in some circles, however, because direct purchase gas is displacing system gas. One direct effect of lower gas prices is a reduction of provincial royalty revenue in Alberta, where royalties are price-based.

Collectives, consortia, brokers, individual enterprises and others are free to negotiate with willing producers/sellers for an agreed amount of gas at a mutually satisfactory price. An arrangement is made with the respective local distribution company whereby the user resells the gas to the LDC before the gas enters the local distribution system. The saving to the user is realized at the moment the LDC takes title of the gas, since the LDC buys it at a higher price.

Transportation arrangements, according to TCPL, are straightforward, and direct-sale gas does not risk being bumped off the pipeline. (Polysar, however, has complained that some of its gas sourced in British Columbia has been bumped off the Nova system, as it passes through Alberta en route to Polysar facilities in Sarnia.)

In the case of direct sales to customers within the territory of Consumers Gas, the LDC arranges transportation, taking title while the gas is still in Western Canada. Union Gas takes title at its system gate. Gaz Métropolitian seems to suggest in its brief that the local distributor is best suited to make transactions with the gas transporter.

The gas users who entered into the buy-sell agreement then repurchase the gas from the LDC as they require it. They pay the full LDC rates applicable to their type and volume of use. When a direct purchase is negotiated, no money is needed up front. Purchasers pay the producer as they resell the gas to the LDC. As purchasers use the gas, they pay the LDC according to use.

The savings for the user group are realized up front, when a profit is taken upon resale to the LDC. In a consortium arrangement, however, the savings are not distributed among participants in the purchasing consortium immediately; this is usually done periodically as the gas is actually used, so the correct share of the savings can be ascribed to each participant. Apart from prorating the share of the savings to be paid to a consortium member, there are no significant accounting complications which might impede participation in direct sales transactions.

Direct Sales to Core Market Users

While direct sales to industrial users are permitted and seen as incremental to the basic sales to LDCs, Alberta has taken the position that short-term direct sales should not be permitted to core-market customers. The core market is most commonly defined to include residential, commercial and small industrial users – users who generally have no immediate alternative fuel capability. In effect, this is a captive market.

The core market is also characterized, according to the Western point of view, as a market needing security of supply because of its lack of adequate economical energy alternatives. Therefore this market should be willing to enter into long-term supply contracts and pay a premium to ensure itself of a long-term supply. Essentially this means respecting present TCPL contracts for system gas.

Eastern consumers have not demonstrated this supposed preference for security of supply. Rather, many of them are opting to take their chances, entering into shorter-term buy-sell agreements and realizing immediate cost savings. In doing so, they effectively refuse to take contract system gas, and risk higher prices or unavailability of supply sometime in the future.

Core market gas users could reasonably argue that if they are being asked to guarantee a long-term market for Western gas producers, they should be given lower prices rather than paying a premium. This position – aside from its obvious political unpopularity in Western Canada – raises problems because the transportation system across Canada was financed on the basis of firm long-term contracts. Even the yearly price negotiations which have lowered system gas contract prices since deregulation were not envisaged when financing for pipeline construction was being arranged. At that time, the government set the price of gas.

It is unclear what might become of financial arrangements to pay for the existing TCPL pipeline and future system expansion if these long-term contracts were to be abrogated. It is the position of many in the industry – and of the Committee – that these contracts must be respected until they expire.

In the meantime, certain large core market users have succeeded in forming collectives and entering into direct sales with gas sourced in Saskatchewan. This group includes school boards and hospitals, and other municipal departments and agencies. While Alberta refuses to permit direct sales to core-market users because these transactions displace higher-priced Alberta system gas sales, Saskatchewan views these sales as incremental, so the province accepts the lower prices offered.

On July 22, 1987, the Alberta Government issued an Order in Council requesting the Public Utilities Board (PUB) and the Energy Resources Conservation Board (ERCB) to hold a joint public inquiry into matters relating to the increased market orientation for natural gas transactions. Among other things, the two Boards were directed to report on "the basis for determining the classes of consumers who should be protected by contracts for the supply of natural gas that ensure long-term security of supply" (Alberta, PUB/ERCB, 1987, p. 11). Note that the directive was not to determine *if* there were classes of consumers who should be protected by long-term supply contracts, but rather to determine *which* classes of consumers should be so protected.

In a report of December 29, 1987, the two Boards defined core market gas consumers to include all residential and commercial users, specifically including any public or private institution providing a service to the public. Certain small-volume industrial users would also fall within the core market definition. The Boards stipulated that the core market should include "those consumers whose dependence on natural gas is so fundamental that assurance of supplies is always a priority" (Alberta, PUB/ERCB, 1987 p. 11). The Boards further recommended that: "The long-term commitments should be for a period of approximately 10 to 15 years, should include peak-day requirements in the current year, and should contain protective back-up sufficient to convince the Boards that the level of security of supply is adequate" (*Ibid.*). These findings had not been acted upon by the Alberta Government at the time of writing.

The Ontario Energy Board (OEB) has taken a rather different position. In a report released August 19, 1988, the OEB argues that "...the focus of attention when addressing the security of Ontario's gas supply should not be directed toward the supply of gas as a commodity. Natural gas will be reasonably available so long as all the participants in the market act in accordance with their declared support for a functioning, competitive marketplace" (Ontario, OEB, 1988, p. 12). Rather the OEB's concern is a possible supply shortfall arising from inadequate pipeline capacity. The Board observes that most of the gas pipeline capacity upstream from Ontario is fully contracted and that a minimum of two years lead-time is required to obtain regulatory approval for new pipeline facilities and to complete their construction. Consequently the OEB recommends that "...LDCs should be directed to transport gas only for those [direct purchasers] that have a contract for supply and transportation having a minimum three year term unless otherwise authorized by the Board" (Ontario, OEB, 1988, p. 15). The Board notes that the three-year rolling contract would be a minimum and that some purchasers – such as the LDCs – may negotiate longer terms to meet specific requirements. Large volume users, such as some industrial consumers, could, with OEB approval, continue to purchase gas on the short-term or spot market.

Can Direct Sales Become a Permanent Feature?

There are various opinions on this point. Those who wish to enter into direct purchases point not only to price savings, but also to the increased flexibility in portfolio management that a wide range of contract options presents. Critics allege that direct sale producers cannot be as reliable as the large collection of gas producers on contract with TCPL.

Some analysts maintain that world oil prices will rise in the 1990s, creating uncertainty and a larger gap between oil and gas prices. In such circumstances, Eastern consumers would be expected to endeavour to sign long-term contracts for security of supply. Thus direct sales arrangements, that now have limited duration (typically one year, though they are usually renewable), may diminish significantly; or else parties to a direct sales transaction may agree to a long-term contract period and a method of adjusting the price.

The point was not raised in the Committee's hearings that direct sales could become longer-term. This could happen when TCPL contracts expire, freeing up gas that now is technically under contract. (TCPL now allows shut-in gas to be sold in direct sales.) How this would impact on the structure of the gas industry is unclear; one possibility is that TCPL would become a common carrier and Western Gas Marketing Limited would then have to compete for market share as would all wholesalers.

LDCs are not altogether enthusiastic about direct sales because of the potentially destabilizing effect should direct-sale customers switch back onto the system because their source of supply becomes unreliable, and also because of the increased storage capability that may be required as a result.

The Committee takes the position that security of supply is the issue of national interest. This interest is best served when the law works in conjunction with forces in the marketplace. The Committee recommends that short-term direct sales to the core market be prohibited. This would leave consumers free to purchase directly from producers in long-term arrangements, consistent with the spirit of the freer market policy of the government; the sanctity of existing long-term contracts for system gas would be upheld, consistent with the principle in law that valid contracts must be respected; consumers would be guaranteed essential supplies of natural gas over the long term; producers would be paid for holding gas on inventory, and the industry assured of the cash flow needed to continue exploration for and development of new reserves; and the federal government would not be assuming a greater role of regulation of the petroleum industry.

How price would be determined or adjusted in long-term direct-sale agreements would be left to the contracting parties to negotiate; market conditions would drive the price negotiations. Producing provinces are free to amend their royalty regimes as they see fit, in response to the new market circumstances. The TOPGAS situation would work itself out as system gas continued to be shipped through TCPL. Finally, the proposal of the Committee is not an impediment to a free and responsible market environment for natural gas marketing in Canada. Moreover, Canadian consumers contracting for long-term supplies of Canadian gas would be assured of supply regardless of any eventualities under the Free Trade Agreement.

The Committee has recommended that regulating interprovincial core market transactions be a responsibility of the National Energy Board. The NEB should rule on whether short-term direct sales may be allowed in particular cases; that is, the Board should have the authority to determine if a particular buyer falls within its definition of the core market. All long-term direct-sale contracts to core buyers would be reviewable by the Board. The Committee also observes that there should be an arbitration process available to the contracting parties if price negotiations become deadlocked.

A Technical Definition of the Core Market

While the core market is usually taken to include all residential, commercial and small-industrial users within the territory of the LDC, not all in this group are incapable of fuel switching. Some industrial and institutional users in this group have dual-fuelling capacity.

Over time, commercial and even residential users can make arrangements to switch off gas, in the same way that many switched off oil. However, this involves a capital expenditure which may well alter the likelihood of and threshold at which the switch will actually be made.

A more precise definition of core market should take into account the sensitivity of this group of users to changes in the price of gas and also to changes in the price of other fuels – in technical terms, to changes in the relative price of gas. This means that the comparative cost of other fuels will drive decisions to switch off natural gas.

A demand curve for core market users would illustrate a continuum of customers who would drop out of the gas market as the relative price of gas rose with respect to alternative fuels. Said another way, progressively more consumers would switch as the price of alternative fuels becomes comparatively lower than gas. Their ability or readiness to switch at any given natural gas price would be expressed as the price elasticity of demand. As the ability to switch diminishes, demand becomes progressively inelastic. It is "inelasticity" which is the technical means of defining the core market. The National Energy Board has adopted this approach in preparing its next natural gas supply and demand estimates.

While inelasticity of demand makes a suitable technical definition, it does not lend itself to practical application on a daily basis in regulatory decision-making. Hence the need for the National Energy Board to hold public hearings in a determination of what constitutes the Canadian core market.

Pipeline Bypass

One difficulty LDCs expect to experience if direct sales become more prevalent is the destabilizing effect of large customers in the LDC service area going off, and possibly coming back on, the LDC system. A similar effect is threatened if industrial users adjacent to the TCPL pipeline attempt to connect directly to the trunk line to avoid going through the local distribution system and paying the tolls of the LDC. This is known as "pipeline bypass", the main effect of which would be to narrow the rate base across a smaller group of consumers. Households and other users still on the LDC system would carry a greater financial burden in supporting the LDC system if a large industrial customer were to be lost.

Bypass is not a hypothetical topic, given the efforts of Cyanamid Canada to build a spur from the TCPL trunk line to an Ontario petrochemical plant. But in testimony before the Committee, industrial users have indicated a willingness to try to work within the system, and regard pipeline bypass as a last resort.

Lower rates to users capable of bypass may become necessary to preserve the integrity of the system – and to spread the financial burden of paying for the local distribution system. LDC rates to industrial customers which are close to bypass costs would presumably keep such users in the system.

Is There a Competitive Gas Market?

Not everyone is convinced that competition is a strong feature of the Canadian natural gas industry, even after the 1985 changes in federal policy.

While the Western Accord and the Agreement on Natural Gas Markets and Prices opened the possibility of more competition by increasing the number of buyers in the market, in practical terms only a small group has been able to take advantage of the new opportunities, due to constraints of existing contracts, financial risk, lack of experience and so forth.

The notion of gas-on-gas competition does not seem to be the central focus of the Canadian debate; the curious situation continues where competition is seen primarily in terms of the ability of gas to underprice alternative fuels.

A true market-determined price, based on the forces of free demand and supply, is not a feature of the Canadian situation, especially when such a large proportion of the transactions – i.e. existing TCPL contracts – fall "in the framework of negotiations imposed by the Government rather than arising spontaneously from market dynamics" as one of the LDCs pointed out. As present TCPL contracts expire, a free market could develop; new long-term contracts may be negotiated between producer and buyer, not by a carrier/seller.

What may produce a truly competitive Canadian gas market is development of the export market. Free trade and the evolution in the American domestic market for natural gas are the factors to be considered. Here, gas-on-gas competition does exist, and, technically, a demand/supply-determined price is the result. The dynamics of these interactions spilling over into the Canadian market will ultimately shape market-determined natural gas pricing in Canada.

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Natural Gas Supply, Demand and Reserves in Canada

A. Natural Gas Supply and Demand

The use of natural gas in Canada has expanded dramatically since the 1950s; today, gas is the second most important commodity in our domestic energy system. In 1986, the output of marketable gas in Canada (pipeline quality gas from which the natural gas liquids have been stripped) amounted to 2,728 petajoules (10^{15} joules or PJ), or approximately 28% of our domestic production of primary energy. Only oil (including liquefied petroleum gases, LPG, stripped from raw natural gas) exceeded it, at 40% of primary energy output.

The share claimed by natural gas of Canada's domestic demand for primary energy was about 25% in 1986. The per capita demand for natural gas has risen from 40.1 gigajoules (10^9 joules or GJ) in 1965 to 94.0 GJ in 1985.

Statistics on Canadian sales of natural gas by class of use reveal that the industrial sector dominates gas consumption in this country. In 1985, industrial users purchased 0.94 Tcf (trillion cubic feet) of gas (for both energy and non-energy purposes), more than the residential (0.45 Tcf) and the commercial sectors (0.38 Tcf) combined. Since 1973, industrial gas sales have generated the largest share of gas utility company revenues. There were at year-end 1985 approximately 3,047,400 residential gas customers, 332,400 commercial customers and 16,300 industrial customers of the gas industry in Canada. That year, residential customers paid an average of $5.28 per Mcf (thousand cubic feet), commercial customers an average of $4.49 per Mcf, and industrial buyers an average of $3.57 per Mcf. For all domestic purchasers of natural gas, the average price paid in 1985 was $4.20 per Mcf.

Gas usage in Canada is supported by an extensive pipeline network which at year-end 1985 consisted of 19,692 miles (31,690 kilometres) of gathering lines, 35,012 miles (56,343 kilometres) of transmission lines, and 77,923 miles (125,398 kilometres) of distribution lines – a total gas pipeline system of 132,627 miles (213,431 kilometres).

On a regional basis, natural gas usage varies markedly across the country. In Alberta, gas accounts for more than 39% of primary energy consumption, exceeding the use of oil within the province. In Atlantic Canada, virtually no gas is used at present because there is no indigenous production nor a delivery system to carry gas into the region. In Quebec, the use of gas has risen to a 13% share of primary energy consumption, fostered by the National Energy Program objective of substituting natural gas for oil in Canada's energy mix and driven by Quebec's unwillingness to be as exposed in the future as it was to the 1973-74 Arab oil embargo. Ontario, the largest provincial consumer of natural gas, uses this commodity to satisfy almost 29% of its primary energy demand. Ontario has the most diversified provincial energy system in the country. Table 1 indicates the relative importance of gas usage by region in Canada, for the year 1986.

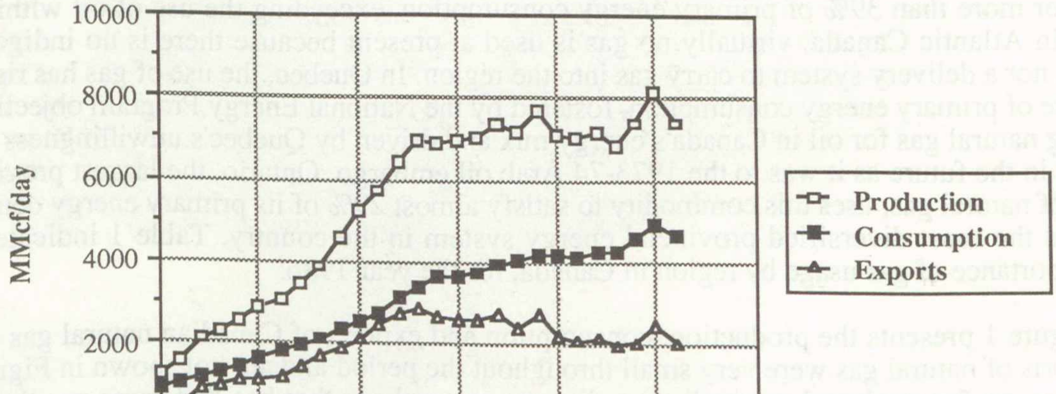
Figure 1 presents the production, consumption and exports of Canadian natural gas since 1960. Imports of natural gas were very small throughout the period and are not shown in Figure 1. The statistics are for marketed or pipeline quality gas, natural gas that has had some or all of the natural gas liquids (NGL) removed through the processing of raw gas. Consumption includes distributor sales of natural gas in Canada, excluding field and pipeline uses and losses. Data expressed in millions of cubic metres per day in the source have been converted to millions of cubic feet per day (MMcf/day), using the approximate conversion factor 1 cubic metre equals 35.5 cubic feet. The slump in export sales since 1973 is evident in Figure 1. In 1987, however, exports almost regained their 1973 level and are running higher in the first half of 1988.

Table 1: Share of Natural Gas in Canada's Regional Primary Energy Use, 1986

Region	Gas	Oil	Coal	Hydro-Electricity	Nuclear-Electricity	Other
Atlantic Canada	-	65.0%	15.5%	8.0%	3.2%	8.3%
Quebec	**13.0%**	42.9	1.5	36.9	0.9	4.8
Ontario	**28.8**	37.2	17.2	5.3	7.8	3.7
Manitoba	**30.6**	42.3	2.0	23.5	-	1.6
Saskatchewan	**29.5**	36.7	28.1	3.5	-	2.2
Alberta	**39.2**	34.1	24.9	0.4	-	1.4
British Columbia	**21.9**	37.5	1.0	20.1	-	19.5
Yukon & NWT	**4.1**	87.6		8.3	-	-
Canada	**24.7%**	**40.2%**	**13.7%**	**12.8%**	**3.2%**	**5.4%**

Source: Canada, Energy, Mines and Resources, *Energy Statistics Handbook*, Ottawa, undated, p. 2.0.6A and 2.0.6B.

Figure 1: Production, Consumption and Exports of Canadian Gas, 1960-1986



Source: Canadian Petroleum Association, *Statistical Handbook*, Calgary, undated, Tables III-10, VII-2/2A and XI-1.

B. Natural Gas Reserves

Canada is estimated by the Canadian Petroleum Association (CPA) to hold about 95.6 Tcf of natural gas reserves, approximately 2.5% of world gas reserves of 3,797 Tcf. [Not all of Canada's gas is currently accessible to the market, however, because a substantial part remains unconnected to any pipeline system.] This share places Canada in ninth position, just ahead of Mexico and far behind the first place U.S.S.R. with its proved reserves of 1,450 Tcf (38.2% of world reserves). The United States ranks third, behind Iran, with an estimated 186.7 Tcf of proved reserves (4.9% of the global total). In terms of raw gas output (before the extraction of natural gas liquids and including field and pipeline uses and losses), however, Canada ranked third in 1987, at 3.47 Tcf or 5.1% of world output. This indicates that Canada is overproducing its natural gas reserves relative to other major gas producing nations (with the notable exception of the United States, which held 4.9% of world proved reserves at year-end 1987 but produced 25.1% of the world's gas last year).

At year-end 1987, Canada's total established reserves of natural gas stood at a calculated 95.6 Tcf. Of this amount, 71.6 Tcf (74.9%) lay in the conventional producing regions of Canada and 24.0 Tcf (25.1%) in the so-called "frontier regions" (the Arctic Islands, the Mackenzie Delta/Beaufort Sea region, and the mainland north of the 60th parallel). Within the conventional gas-producing regions of Canada, Alberta claims the bulk of the reserve, at 61.3 Tcf. Table 2 displays year-end 1987 gas reserves data for Canada. 1987 production statistics are also included in Table 2 to show what fraction of the reserve is being consumed on an annual basis.

Table 2: Natural Gas Reserves and Production in Canada, 1987

Area	Proved Reserves (Tcf)	Production (Tcf)
Conventional Areas		
British Columbia	7.47	0.28
Alberta	61.33	2.46
Saskatchewan	2.16	0.09
Ontario	0.64	0.01
Frontier Areas		
Mainland	0.40	(a)
Mackenzie Delta/ Beaufort Sea	9.17	–
Arctic Islands	14.43	–
Totals	**95.59**	**2.84**

(a) Gas production in the Mainland Territories in 1987 was less than 0.005 Tcf.

Source: Canadian Petroleum Association, *Statistical Handbook*, Calgary, undated, Table II-2.

The reserves-to-production (R/P) ratio for Canada is almost 34 years when the 1987 output of 2.84 Tcf is measured against the total established reserves of 95.6 Tcf. For Alberta alone, however, the R/P ratio is 25 years. This is because Alberta holds 64% of Canada's total established reserves but accounted for 87% of the total Canadian production of natural gas in 1987.

The CPA does not yet attribute any established reserves to Canada's East Coast offshore region.

Deregulation of the Canadian Gas Market

A. The Period 1975–1985

Beginning in 1975, in the aftermath of the first OPEC oil price shock, the price of Alberta natural gas sold in Saskatchewan, Manitoba, Ontario and Quebec was administered under an agreement between the Governments of Canada and Alberta. In the next decade, the price of natural gas was linked to the administered price for crude oil.

From 1975 to 1981, the price of gas was set at approximately 85% of the crude oil price, on an energy equivalent basis. From 1981 to the beginning of 1985, the relationship was set at 65%. As part of the Western Accord, the two governments then agreed to freeze the Alberta border price of natural gas at the level of $2.79 per gigajoule (GJ) for the period April 1 to November 1 of 1985.

B. The Western Accord of 1985

In the Western Accord of March 28, 1985, the Governments of Canada, Alberta, British Columbia and Saskatchewan agreed to modify the then-existing regime of energy pricing and taxation. The four governments adopted the view that market-sensitive pricing for both oil and gas, and profit-sensitive taxation, would stimulate investment and job creation in the energy sector while promoting energy security for Canadians.

Part II of the Accord – Domestic Natural Gas Pricing – contained five provisions to facilitate the development of a market-sensitive pricing system for natural gas:

1. The Alberta border price will remain at its present level pending the introduction of a new domestic natural gas pricing regime on or before November 1, 1985.

2. A task force of senior officials from the federal government and the producing provinces will work with all interested parties, including consuming provinces and industry, to develop a more flexible market-sensitive pricing mechanism on or before November 1, 1985.

3. The subsidy of TransCanada PipeLines tariffs under the federal Transportation Assistance Program will be terminated in conjunction with the elimination of the Canadian Ownership Special Charge.

4. The Natural Gas Market Incentive Plan under which Alberta producers provide a price discount to industrial customers in eastern Canada will be extended for one year until April 30, 1986.

5. The Market Development Incentive Payments by the Province of Alberta to the Government of Canada will terminate following payments for gas delivered up to April 30, 1986, or to a maximum level of $160 million in additional payments, whichever comes first.

C. The 1985 Agreement on Natural Gas Markets and Prices

The Western Accord was followed by the October 31, 1985 Agreement among the Governments of Canada, Alberta, British Columbia and Saskatchewan on Natural Gas Markets and Prices. This new Agreement was intended to promote an orderly transition to market-sensitive pricing, creating an environment in which gas prices and other terms of gas transactions could be freely negotiated between buyers and sellers.

The Agreement was founded on three principles:

1. Effective November 1, 1986, the prices of all natural gas in interprovincial trade will be determined by negotiation between buyers and sellers. Access will be immediately enhanced for Canadian buyers to natural gas supplies and for Canadian producers to natural gas markets while at the same time assuring that the reasonably foreseeable requirements of gas for use in Canada are protected.

2. The twelve month period commencing November 1, 1985 is the transition to a fully market sensitive pricing regime. While prices will continue to be prescribed by governments, immediate steps will be taken to enable gas consumers to enter into supply arrangements with gas producers at negotiated prices (direct sales), which prices will then promptly be endorsed by governments in the context of the administered system. After this transition period, purchase and sale of natural gas will be freely negotiated, and prices will no longer be prescribed.

3. It is the intention of the parties to the Agreement to foster a competitive market for natural gas in Canada, consistent with the regulated character of the transmission and distribution sectors of the gas industry. In this regard the governments commit, without qualification, that once the transition to the new marketing and pricing system is completed, the system will stay in place for the foreseeable future.

Deregulation has not proceeded as smoothly as the Agreement anticipated, in part because the sharp decline in crude oil and natural gas prices of 1986 was not foreseen. As well, there was the continuing problem of take-or-pay contract obligations to be resolved and the modification of NEB supply tests to allow natural gas more readily into the export market.

D. Evolution in NEB Supply Tests

During the period 1960-1986, the NEB maintained formal tests to determine the amount of gas which was surplus to Canadian needs and therefore available for export. This approach was prompted by Section 83 of the *National Energy Board Act* which requires that, before the Board can license the export of natural gas:

> ...the Board shall have regard to all considerations that appear to it to be relevant and, without limiting the generality of the foregoing, the Board shall
>
> (a) satisfy itself that the quantity of...gas...to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada having regard, in the case of an application to export...gas, to the trends in the discovery of...gas in Canada...

A **Reserves Formula**, in place throughout the period 1960-1986, set aside an amount of established gas reserves equal to 25 times the current year's domestic demand (known as "25A1"), plus the maximum volume of gas that could flow under existing export licences. Excess volumes of reserves were deemed to be surplus and available for export. The multiple of 25 reflected the term of export licences issued early in the Board's operations, when long-term contracts were required for financing new pipeline facilities.

An additional **Deliverability Test**, introduced in 1979, was in place until 1986. This test compared the Board's estimates of future gas supply and demand on a year-to-year basis. The future supply from both established reserves and anticipated future reserve additions was forecast. On the demand side, projected Canadian requirements were added to estimated exports under existing licences (that is, the export volumes actually expected to flow rather than the maximum volume authorized).

In a 1985 hearing, the Board reviewed its methodology for determining surplus gas available for export and, in April of 1986, modified its test to what was termed the **Reserves to Production Ratio** procedure. This procedure was based on maintaining a ratio of 15 between reserves and total annual production, and incorporated estimates of annual additions to established reserves, forecasts of domestic demand, and forecasts of exports under existing authorizations. In addition, a **Productive Capacity Check** assessed productive capacity year-by-year to ensure that forecast total demand could be met in each year of the projection.

The 1985 Agreement among the Governments of Canada, Alberta, British Columbia, and Saskatchewan on Natural Gas Markets and Prices provided for a transition from government-administered pricing of natural gas to a market-oriented regime over a transition period ending in October 1986. At the close of the transition year, the Minister of Energy, Mines and Resources requested that the NEB again review its gas surplus determination procedures. The Board did so and concluded that the Reserves to Production Ratio procedure would not be appropriate in the new environment of market-oriented pricing. Consequently, the Board on September 9, 1987 announced its new **Market-Based Procedure** for determining the surplus of Canadian natural gas available for export.

In its press release of September 9, 1987, the NEB summarized the new procedure in the following terms:

> The Board will act in two ways to ensure that natural gas to be licensed for export is surplus to Canadian needs: one will be in the context of public hearings to consider applications for licences to export natural gas; the other will be by monitoring on an ongoing basis.
>
> The public hearings part of the Market-Based Procedure includes the following three components:
>
> *1) Complaints Procedure* – In the public hearing process, the Board will consider complaints that Canadian users cannot obtain additional supplies of gas under contract on terms and conditions, including price, similar to those in the export proposal. If the Board finds merit in a complaint that Canadians have not been able to contract for gas on a similar basis, it may deny the application or defer issuing a final decision on it until an opportunity has been given for the situation to be rectified.
>
> *2) Export Impact Assessment* – The Board will require applicants for export licences to file an impact assessment which will allow the Board to determine whether a proposed export is likely to cause Canadians difficulty in meeting their energy requirements at fair market prices.
>
> *3) Public Interest Determination* – The Board will continue, as required by Section 83 of the Act, to have regard for all other factors it considers relevant in determining whether proposed export licences are in the national public interest.
>
> As part of the new procedure, the Board will continue to publish its biennial staff study on *Canadian Energy Supply and Demand*. This study contains

projections of the Canadian supply of all major energy commodities, including electricity, oil and natural gas, and the demand for Canadian energy in Canada and abroad.

The Board also plans to periodically publish reports analyzing natural gas supply, demand and prices. These reports will deal with recent developments in and near-term prospects for natural gas markets, and provide comments on competitive activity in the market, on pipeline utilization for Canadian and export purposes and on the quantity and quality of gas supply.

E. The Take-or-Pay Problem

TransCanada PipeLines Limited began operations in October 1958. It has traditionally operated as a buy-sell pipeline, purchasing most of the natural gas to be transported through its system for resale to local distribution companies in the Canadian market east of Alberta. Until recently, TCPL was under no obligation to carry gas for third parties.

This was a practical arrangement at the time as TCPL linked hundreds of gas producers in Western Canada to new distribution companies, principally in southern Ontario, which were largely occupied with market development in their service areas. At the eastern end of the system, TCPL provided gas distributors with both gas transmission and a gas acquisition service.

TransCanada has traditionally arranged for its system gas supply from Alberta producers with contracts which included take-or-pay clauses. These clauses required TCPL to take minimum specified volumes. If these minimum volumes were not taken, TCPL was still obligated to pay for the gas and had the right to take this gas within a specified period. Failing that, TCPL lost the right to acquire this prepaid gas.

Take-or-pay clauses are not unique to Canada – they have been common practice in the United States as well. Take-or-pay ensured gas producers of a minimum cash flow, enabling them to obtain financing for future gas exploration and development activities. In turn, the long-term gas purchase contracts assisted the pipeline companies in obtaining funds for constructing new transmission facilities, as an assurance of committed supplies to sustain pipeline operations.

In the 1960s, as domestic and export demand for Canadian natural gas grew continually, the minimum take clauses presented no problems to TCPL. Growth in demand accelerated from 1967 on and, by mid-1971, the National Energy Board concluded that Canadian deliverability of natural gas could not keep pace with demand and therefore no new exports would be allowed. Domestic gas and crude oil supply tightened further from 1971 through 1973, and the Arab oil embargo raised new fears. Canada was seen to be facing an impending shortage of both natural gas and conventional light crude oil; gas distribution companies expressed concern about the long-term security of their gas supplies.

TCPL moved aggressively to contract for new Alberta gas supplies between 1974 and 1976, providing incentives to producers to establish new reserves. TCPL increased its minimum take obligations and entered into area-based contracts that allowed producers to include additional volumes of gas found within specified areas to be covered in TCPL's gas purchase contracts.

At the same time that TCPL was working to augment its supplies of system gas, negotiations between the Federal and Alberta Governments were proceeding in the wake of the embargo and first oil price shock. Natural gas prices became subject to government regulation on November 1, 1975, and the gas price provisions in TCPL's purchase contracts were overridden.

Increasing gas prices arrested the growth in consumer demand but also stimulated producers to establish new reserves. TCPL ceased contracting for new gas supplies early in 1977 but system gas supplies grew nonetheless as producers responded to the twin incentives of higher prices and the opportunity to boost minimum sales of system gas through the area-based contracts. On the other hand, TCPL was prevented by the regulated pricing structure from marketing the gas at lower prices in an effort to spur weakening demand.

TCPL incurred its first major take-or-pay liabilities in the 1977/78 gas contract year, paying $134 million to producers for gas that it could not take. Believing that take-or-pay was a transient problem and that domestic gas demand would soon resume its growth, TCPL continued to make full payments for gas not taken through the 1979/80 contract year.

In 1980, following the Iranian Revolution and the onset of the Iran-Iraq war, the federal government moved to peg the price of natural gas at 65% of the energy-equivalent price of crude oil. Despite this relatively low price compared with oil, demand for gas continued to stagnate in Canada. Concurrently, TCPL's system producers continued to exploit their area-based contracts with active drilling programs, driving up TCPL's contracted supplies. Faced with increasing difficulty in meeting its take-or-pay obligations, TCPL negotiated a new allocation program with its producers, which reduced the minimum take obligation from 100% to 80% of contracted levels for the 1980/81 and 1981/82 contract years.

By the end of 1981, TCPL had paid out a billion dollars for gas that it had been unable to take and the continuing take-or-pay commitments were becoming a substantial impediment for the company. Clearly a more comprehensive solution to the problem was required. The result was the first TOPGAS agreement.

The TOPGAS I arrangement was proposed in May of 1982 and implemented that autumn. Under the TOPGAS I Agreement, a new corporate entity – TOPGAS Holdings Ltd. – was created. TOPGAS is a consortium of 30 domestic and foreign banks and financial institutions which assumed TCPL's outstanding take-or-pay liabilities and advanced $2.3 billion to the system gas producers. In return for receiving the badly needed payments from the TOPGAS consortium, producers became liable for the take-or-pay obligation. Of the $2.3 billion amount, $1 billion covered TCPL's earlier payments to producers. The producers were in turn required to refund this amount to TCPL, thereby enabling the company to remove from its balance sheet the $1 billion in debt obligations which had been incurred in making the earlier payments. The remainder of the advance to producers – about $1.3 billion – covered take-or-pay obligations for the 1980/81 and 1981/82 gas contract years.

Of this latter $1.3 billion, approximately $1 billion represented payments for gas that producers had already agreed to forego under the then-existing allocation program (in which producers had agreed to reduce TCPL's minimum take requirements to 80% of contracted levels). In return for the producers now receiving these payments, they accepted a further reduction in TCPL's future take-or-pay obligations, to the lesser of (a) 60% of the minimum annual contract obligation for the 1981/82 contract year, or (b) 75% of TCPL's minimum annual obligation for the year in question.

TCPL's gas sales did not improve in the 1982/83 contract year and the company failed to fulfill its minimum take obligations under the TOPGAS I Agreement. The result was TOPGAS Two Inc., a consortium of 20 domestic and foreign banks and financial institutions, which advanced an additional $350 million to producers for gas not taken in the 1982/83 contract year. In return, TCPL's minimum annual take-or-pay obligation for the 1983/84 contract year was set at 50% of the 1981/82 obligation and at 50-60% of the 1981/82 obligation in subsequent years (depending on actual delivery levels in the immediately preceding two years). Once again, TCPL was able to remove its take-or-pay liabilities from its balance sheet as these were assumed by

TOPGAS Two Inc.

The system gas producers began repayment of the TOPGAS advances in November 1984. Repayment at the minimum specified level would retire the debt by 1994.

The system gas producers are liable for both the principal and interest owing on the TOPGAS advances; TCPL acts as the collection agency in the arrangement. TCPL nevertheless has an unlimited liability to the TOPGAS consortia if producers default on payment of the carrying charges and is also liable for up to $355 million in the event that producers default on repayments of the principal.

The TOPGAS Agreements were unusual in that the consortia advanced about $2.65 billion to producers without the gas in question being secured as collateral against the advances. At the time, TCPL's dominant market position in effect guaranteed that the TOPGAS advances would be paid: in the event of a producer bankruptcy, a receiver would have had little choice but to sell the gas to TCPL as the only practical outlet for system gas producers. The October 1985 Agreement on Natural Gas Markets and Prices overturned this presumption of market dominance.

With the prospect that direct sales gas could displace significant amounts of TCPL system gas, the underpinning of the TOPGAS Agreements was threatened on three counts: (1) displacement of system gas would force the TOPGAS carrying charges to be spread over a smaller volume of sales at the same time that competing non-system gas could be driving all gas prices down (as a result of the Agreement on Natural Gas Markets and Prices, prices in system gas contracts came to be negotiated annually), potentially causing some producers to be unable to honour their obligations under the Agreements; (2) if TCPL's system gas sales were seriously eroded, TCPL could incur new take-or-pay liabilities, despite the renegotiated minimum takes; and (3) in the event of producer bankruptcies, a trustee would now have the option of selling gas via the direct sale route and avoiding the TOPGAS obligation.

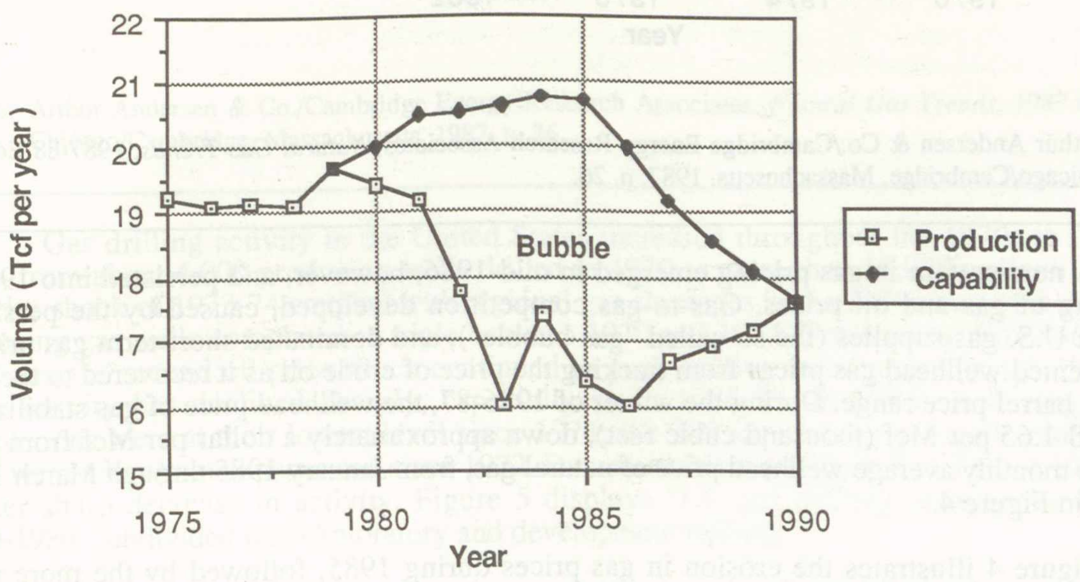
The solution arrived at by the National Energy Board was to assign demand tolls based upon operational volumes of natural gas rather than contract volumes. The operating demand level for each distribution company was defined as the contract demand volume specified in its contract with TCPL minus the volume of all direct displacement sales occurring within its franchise area. This approach resolved the matter of double demand charges. Further, the direct sales (non-system) gas would have to share responsibility in meeting the TOPGAS carrying charges, although at a rate approximately half that assessed against system gas. Thus non-system gas attracts a charge of about 50% of the TOPGAS unit carrying charge assessed under existing methodology on system gas.

Natural Gas Supply, Demand and Reserves in the United States

A. Natural Gas Supply and Demand

American natural gas production capability or gas deliverability currently exceeds the domestic demand for natural gas. The "gas bubble" is the difference between gas production capability and actual U.S. production. There are currently about 240,000 producing gas wells in the United States plus gas output from oil fields. The bubble first appeared in 1980, as production capability rose in response to increased drilling activity although demand was falling. Figure 2 displays the American Gas Association (AGA) view of the duration and size of the gas bubble. The bubble reached a maximum of almost 4.6 Tcf in 1983 and had diminished to about 4.0 Tcf by 1986. The AGA projected a 2.5 Tcf bubble for full-year 1987, with the bubble essentially disappearing in 1990. The annual U.S. purchase of Canadian gas in the AGA analysis is assumed to run at about 1 Tcf in the late 1980s.

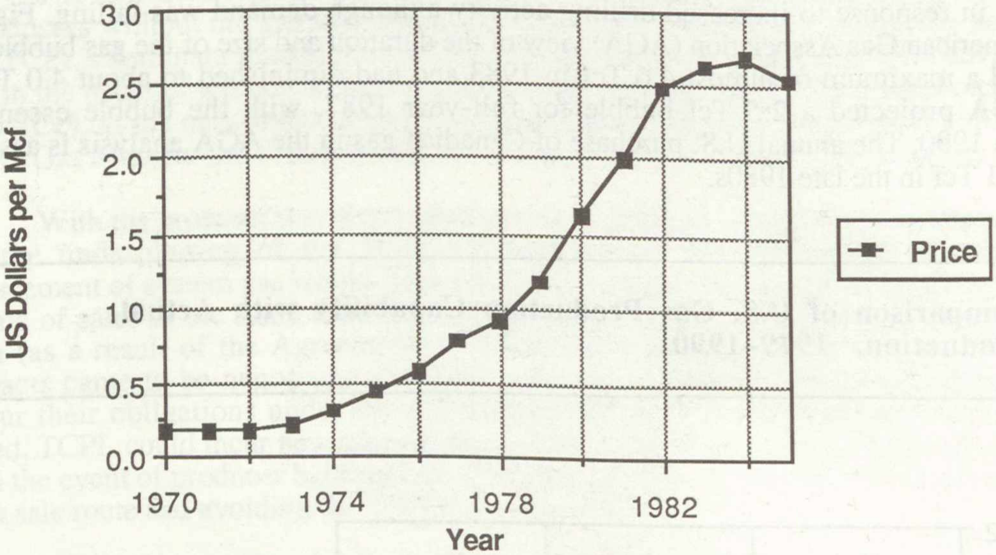
Figure 2: Comparison of U.S. Gas Production Capability with Actual Production, 1979–1990



Source: American Gas Association, *Natural Gas Production Capability 1987-1990*, Issue Brief 1987-7, 13 July 1987, Arlington, Virginia, p. 4 and 6.

Following a continuous rise in the average annual wellhead price of natural gas in the lower 48 states over the period 1970–1984, the price began to decline in 1985, as displayed in Figure 3. The collapse of crude oil prices in the first half of 1986 drove the wellhead price of gas down further, as gas producers demonstrated their willingness to compete with fuel oil at the burner-tip. Spot gas prices at the wellhead were generally based on netbacks from the burner-tip, and so were able to respond quickly to changes in oil prices.

Figure 3: Average Annual Wellhead Gas Price in the Lower 48 States, 1970–1985

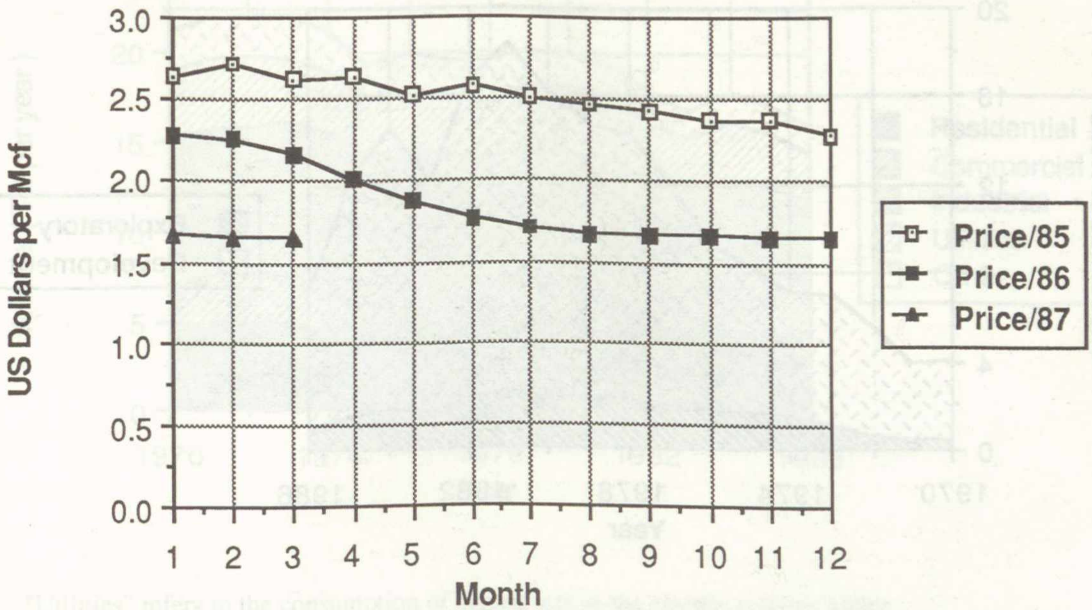


Source: Arthur Andersen & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 26.

A new pattern in gas pricing emerged in mid-1986, however, and persisted into 1987: a decoupling of gas and oil prices. Gas-to-gas competition developed, caused by the persistent surplus in U.S. gas supplies (the so-called "gas bubble"), and dominated short-term gas pricing. This prevented wellhead gas prices from tracking the price of crude oil as it recovered to the $US 18-20 per barrel price range. During the winter of 1986-87, the wellhead price of gas stabilized at about $US 1.65 per Mcf (thousand cubic feet), down approximately a dollar per Mcf from early 1985. The monthly average wellhead price of natural gas, from January 1985 through March 1987, is shown in Figure 4.

Figure 4 illustrates the erosion in gas prices during 1985, followed by the more rapid decline in the first half of 1986, as the average wellhead price of natural gas tracked falling oil prices. Thereafter, the price of gas stabilized at the new lower level as gas-to-gas competition developed.

Figure 4: Monthly Average Wellhead Gas Price in the Lower 48 States, January 1985–March 1987

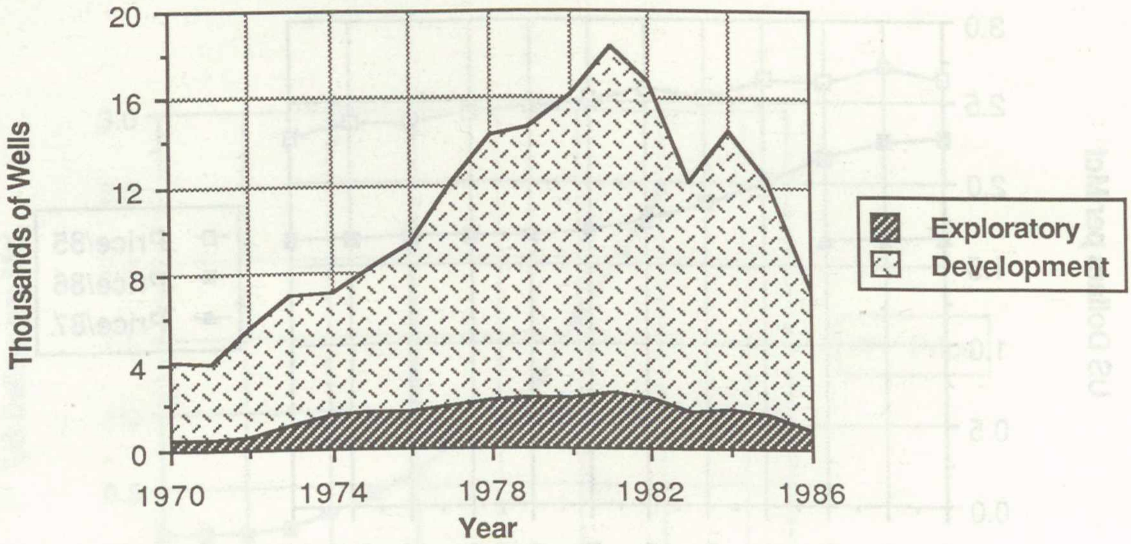


Source: Arthur Andersen & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 26.

Gas drilling activity in the United States increased throughout the 1970s to its peak in 1981, from about 4,000 producing wells drilled in 1970 to more than 18,000 wells in 1981. The oil price shock of 1973-74 coupled with regional gas shortages in the 1970s caused the number of producing gas wells completed to triple between 1970 and 1977. The *Natural Gas Policy Act* of 1978 and the second oil price shock continued to push drilling activity up through 1981. Since then, activity has declined sharply, especially so in 1986-87. In 1986, producing gas well completions were at their lowest level since 1974; the 900 exploratory gas well completions of 1986 were a level not experienced since 1972. Data available through the first half of 1987 show a further sharp decrease in activity. Figure 5 displays U.S. gas drilling activity for the period 1970-1986, subdivided into exploratory and development drilling.

A noteworthy feature of American gas drilling is that exploratory well completions only accounted for between 12% and 21% of all producing gas wells completed over the 1970 through 1986 period. Most of the activity has been infill drilling in established fields. In the first half of 1987, exploratory wells represented 14.2% of all producing gas well completions, up from the 12.5% recorded in 1986.

Figure 5: Exploratory and Development Drilling of Producing Gas Wells in the United States, 1970–1986



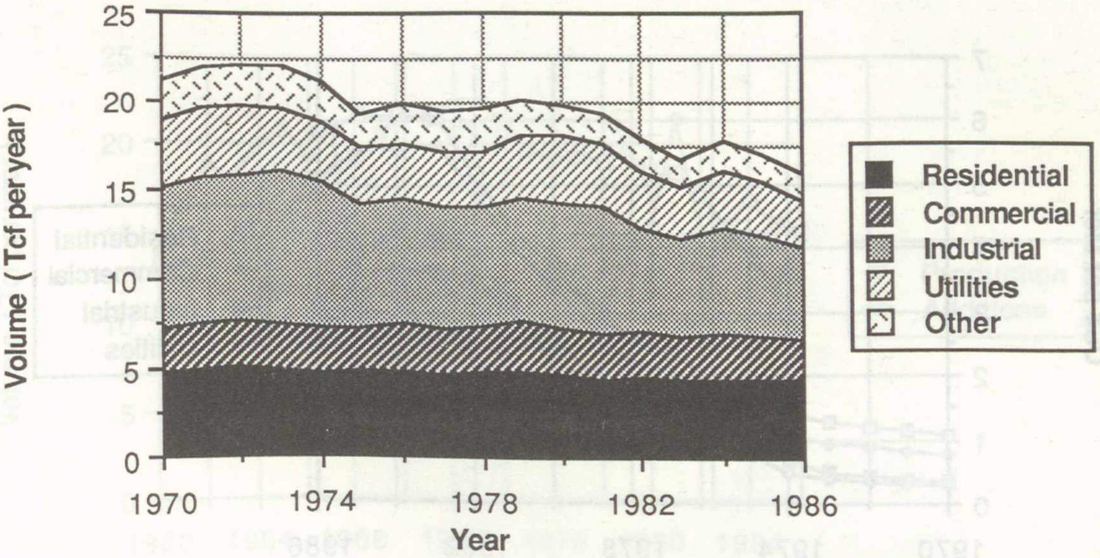
Source: Arthur Andersen & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 28.

U.S. demand for natural gas has been in general decline since the early 1970s. In 1986, domestic demand reached its lowest level in 21 years, at 16.0 Tcf, down almost 28% from the peak of 22.1 Tcf in 1972. This decline has occurred in all sectors of gas consumption, but has been steepest in the industrial sector (where the drop has been 40% since the 1973 peak) and in the use of natural gas for electrical generation by utilities (where the decrease has been 35% since the 1972 peak). Gas demand by end-use sector is presented in Figure 6.

The particularly large decline in industrial gas consumption is attributed to three factors: fuel switching, with gas sales lost in competition with fuel oil (especially evident in 1986); structural changes in U.S. industry; and improvements in the efficiency of energy use.

Statistics for 1987 indicate that domestic demand registered a significant increase last year, with U.S. gas plant throughput up by almost 8% and consumption above 17 Tcf for the year. In part this reflects a turn-around in the use of gas for electrical generation. U.S. utilities are running out of spare generating capacity. Unwilling or unable to invest in new nuclear units and large coal-fired units, many electric utilities are buying power from independent power producers who are installing gas-fired cogenerating units, a development encouraged by the *Public Utilities Regulatory Policies Act* (PURPA) of 1978. This activity is also providing a new market for Canadian exporters – Gas Alternative Systems Inc. of the United States recently signed a contract with Canadian Hunter Exploration to purchase 120 billion cubic feet of gas over a period of up to 20 years to fuel a new gas-fired cogenerating station at Syracuse, New York.

Figure 6: U.S. Natural Gas Consumption by End-use Sector, 1970–1986



Notes: "Utilities" refers to the consumption of natural gas in the electric utilities sector.

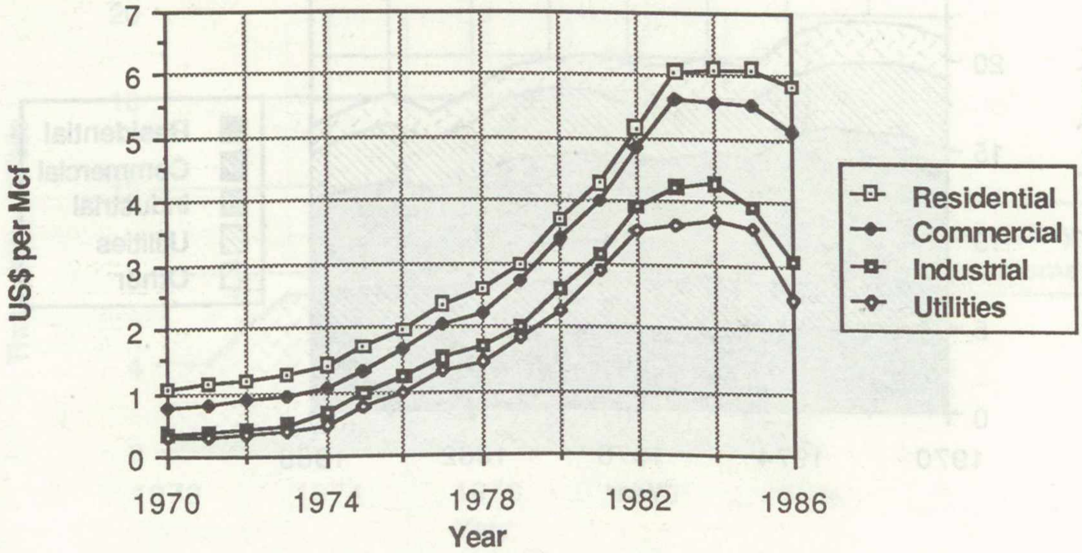
"Other" includes gas consumed as lease and plant fuel, gas consumed as pipeline fuel, and gas unaccounted for.

Source: Arthur Andersen & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 46.

Average gas prices to end-use sectors rose steadily throughout the 1970s and then grew even more rapidly until 1983, as illustrated in Figure 7. The average end-use price of gas across all sectors peaked in the lower 48 states in 1984 at $US 4.89 per Mcf. From 1984 through 1986, the average end-use price of gas fell by 13%, but the decline was larger in the industrial and electric utilities sectors (down 27% and 35%, respectively) and smaller in the residential and commercial sectors (where it dropped by 5% and 8%, respectively). Thus the rate tilt against industrial and electric utility customers which was amplified in the 1970s has been partially reduced in the 1980s. In response to the oil price increases of the 1970s and early 1980s, many industrial and utility operations converted to dual-fueling, allowing them to engage in fuel switching as the relative prices of fuels altered. Local gas distribution companies have been compelled to offer lower prices to these classes of buyer to prevent fuel switching.

Residential and commercial customers have historically paid more for gas in the United States, primarily because of a higher cost-of-service associated with the large number and comparatively small individual consumption of these groups of users.

Figure 7: Average Gas Prices to End-use Sectors in the Lower 48 States, 1970–1986



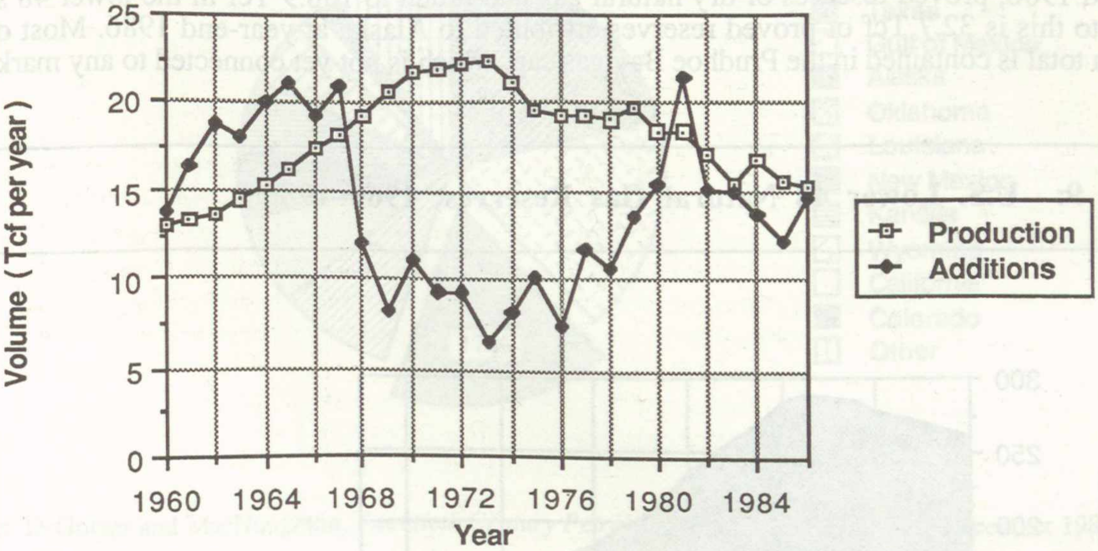
Source: Arthur Andersen & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 50.

B. Natural Gas Reserves

At year-end 1987, U.S. proved reserves of natural gas were estimated to be 186.7 Tcf, or 4.9% of the world total. This placed the United States third behind the U.S.S.R. with 1,450 Tcf and Iran with 489 Tcf. U.S. gas production, however, at 17.1 Tcf was 25.1% of global output, second behind the Soviet Union at 25.7 Tcf (37.7%). This left the United States with a reserves-to-production ratio of less than 11. Excluding the 33 Tcf of Alaskan gas contained primarily in the Prudhoe Bay gas cap and not available to the market, the lower 48 states have a R/P ratio of 9.

Additions to proved gas reserves in the lower 48 states have exceeded production in only one or two years following 1967 (depending upon which set of reserves statistics is used). During the 1970s, reserve additions only amounted to 45% of production. Since the late 1970s, however, the U.S. petroleum industry has come much closer to replacing produced gas, in part because demand is down substantially and in part because exploratory and development drilling reached record levels in 1981, in the wake of the second oil price shock and the passage of the *Natural Gas Policy Act*. Over the period 1981-86, the natural gas industry replaced 93% of production with new reserves. The situation since 1960 is illustrated in Figure 8.

Figure 8: Proved Dry Gas Reserve Additions and Production in the Lower 48 States, 1960–1986



Notes: "Production" refers to the output of dry natural gas (that is, with the natural gas liquids removed).

"Additions" refers to net additions to proved reserves of dry natural gas.

Source: American Gas Association, *The Gas Energy Supply Outlook 1987–2010*, Arlington, Virginia, October 1987, p. 50.

U.S. gas reserves fell most sharply between 1970 and 1977, during which time

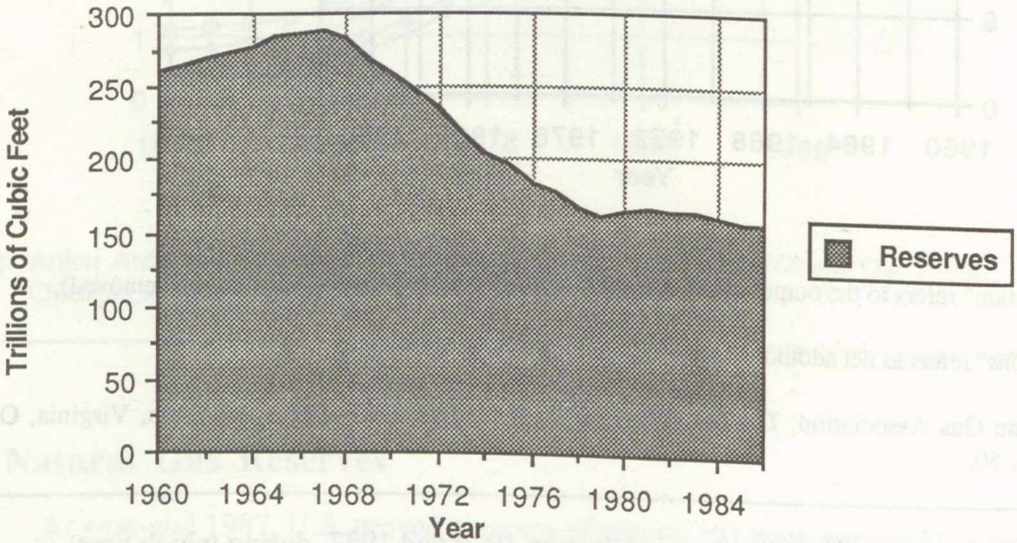
> ...artificially low, regulated wellhead prices for gas in the interstate market gave little incentive for exploration and production. The emergence of a strong intrastate market with higher unregulated prices, together with increases in regulated prices of interstate gas supplies, resulted in significant additions to reserves during 1977 and 1978... The passage of the *Natural Gas Policy Act* in 1978, coupled with the dramatic increases in the price of oil in the late 1970's and early 1980's, led to significantly higher exploration and development activities in the early 1980's, and increased discoveries of gas reserves. Upward revisions and extensions of existing reserves which had been uneconomic to produce at the prices of the early 1970's also provided significant additions to reserves. From 1978 until the mid-1980's these economic incentives and the resulting exploration and development activity caused the decline in reserves to slow considerably, but only twice during that period did net additions to reserves exceed production..." (*Natural Gas Trends*, 1987-88 Edition, Arthur Andersen & Co., Chicago/Cambridge Energy Research Associates, Cambridge, Massachusetts, 1987, p. 19.)

U.S. gas output has fallen most dramatically in the Texas/Gulf Coast region (essentially

Texas and Louisiana). From 11.8 Tcf extracted in 1971, production fell in this part of the United States by almost 51% to 5.8 Tcf in 1986. This reflects a 66% decline in proved reserves in the region, from 142.9 Tcf in 1970 to just 48.5 Tcf at year-end 1986. For the Texas/Gulf Coast and Gulf of Mexico combined, the reserves-to-production ratio is only 8.3. For the lower 48 states taken together, the ratio is about 9.

The evolution in the lower 48 states proved reserves of natural gas is presented in Figure 9. Reserves grew throughout the postwar period until reaching a peak of 289.3 Tcf in 1967. By year-end 1986, proved reserves of dry natural gas had fallen to 158.9 Tcf in the lower 48 states. Added to this is 32.7 Tcf of proved reserves attributed to Alaska at year-end 1986. Most of this Alaskan total is contained in the Prudhoe Bay gas cap, which is not yet connected to any market.

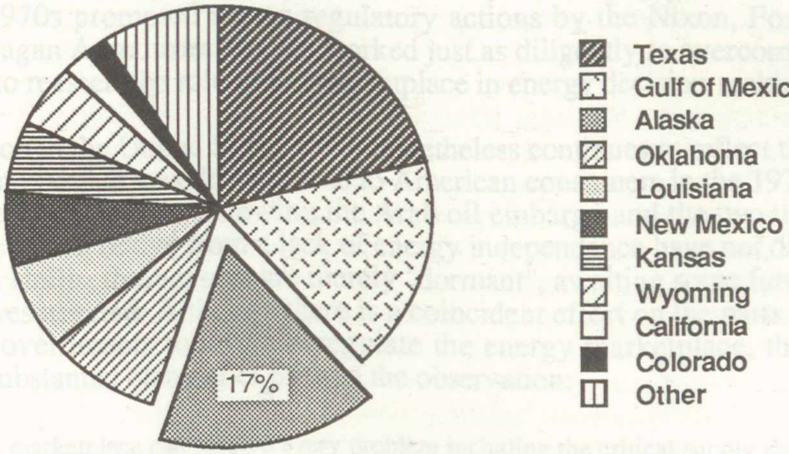
Figure 9: U.S. Lower 48 Natural Gas Reserves, 1960–1986



Source: American Gas Association, *The Gas Energy Supply Outlook 1987–2010*, Arlington, Virginia, October 1987, p. 50.

Figure 10 shows the breakdown in proved reserves of natural gas by state, including Alaska, as of year-end 1986. Alaska's 17% share of U.S. reserves is set apart because there is no means yet for delivering this gas to market. The Gulf of Mexico, lying off Texas and Louisiana, is evaluated separately from the state totals by the U.S. Department of Energy. In the DOE compilation, Texas still holds the largest quantity of proved reserves at 40.6 Tcf (21.2% of total U.S. gas reserves, including Alaska). The Gulf of Mexico stands second at 32.9 Tcf (17.2% of U.S. reserves), narrowly ahead of Alaska at 32.7 Tcf (17.1%). Oklahoma is assigned 16.7 Tcf (8.7%), Louisiana 12.9 Tcf (6.7%), New Mexico 11.8 Tcf (6.2%), Kansas 10.5 Tcf (5.5%), Wyoming 9.8 Tcf (5.1%), California 3.9 Tcf (2.0%) and Colorado 3.0 Tcf (1.6%). The 50-state total (including the Gulf of Mexico) at year-end 1986 was 191.6 Tcf of proved gas reserves.

Figure 10: U.S. Proved Reserves of Natural Gas by State at Year-end 1986



Source: DeGolyer and MacNaughton, *Twentieth Century Petroleum Statistics 1987*, Dallas, December 1987, p. 74.

Deregulation of the U.S. Gas Market

A. Introduction

The United States has developed the most complex energy system in the world. This system sustains a population nearing 250 million and is closely watched by powerful interests. The energy shocks of the 1970s prompted strong regulatory actions by the Nixon, Ford and Carter Administrations; the Reagan Administration has worked just as diligently to overcome the "energy scarcity mentality" and to reassert the role of the marketplace in energy decision-making.

Energy regulation in the United States today nonetheless continues to reflect the problem of foreign energy dependence which was driven home to American consumers in the 1970s. Although that dependence lessened in the years following the Arab oil embargo and the two upsurges in oil prices, the energy issues which derive from a lack of energy independence have not disappeared. In the view of Tomain and Hollis, these issues are merely "dormant", awaiting some future disruption in foreign supply to be resurrected. Although there is a coincident effort on the parts of the United States and Canadian Governments today to deregulate the energy marketplace, the Committee considers there to be a substantial element of truth in the observation:

> ...A belief that the marketplace can resolve every problem including the critical supply shortage is misplaced. The present [Reagan] administration should not ignore history and rely on the market to ensure even the roughest justice in the distribution of hardship and burden in a supply crisis. Thus, dismantlement of virtually all institutional structures to deal with supply interruption is a simplistic answer to complex issues of governance of the nation in an area of fundamental importance... (Tomain and Hollis, 1983, p. xiv)

The energy component of the Free Trade Agreement (FTA) is in part an institutional response to dealing with future disruptions in energy supply, as are the oil-sharing provisions agreed to by the member nations of the International Energy Agency. The Committee believes that American policy-makers perceive this more clearly than do Canadian policy-makers (or than they are willing to admit in public). It is not surprising to Committee members that a number of Americans in discussions with the Committee characterized the energy component of the Agreement as the most important element of the FTA for their country.

In this section of the report, the Committee briefly reviews its findings on the U.S. regulatory system as it pertains to the natural gas market in that country. This review is little more than a snapshot of a system in change. While we appreciate that the United States has mounted a major and sustained effort to deregulate its energy system, we are also well aware that the pendulum swings in both directions as circumstances change. The Free Trade Agreement will certainly make it more difficult, however, for subsequent governments in both countries to backtrack on their commitment to deregulated energy markets.

B. The Road to Deregulation

The U.S. Federal Power Commission (FPC) is the forerunner of institutions which today are at the focus of American regulatory activity in the energy sector. At its inception in 1920, the FPC had authority only in the matter of hydro-electric facilities on navigable waterways. This changed, however, during the Roosevelt Administration with its "New Deal" philosophy of addressing difficulties in the U.S. economy. This period witnessed rapid growth in the number and powers of federal agencies, which were seen as effective agents of broad economic regulation. According to Tomain and Hollis, three important characteristics were attributed to the New Deal agencies.

First, federal administrative agencies are specialized creations of Congress charged with administering complex laws and regulations. Recognizing that Congress could not cope with all the subtleties and complexities of regulating monopolistic enterprises, these agencies were to acquire specialized expertise. Second, the heads of these agencies are appointed, not elected, and this freedom from direct political accountability was seen as allowing the agencies to function without the compromises arising from political pressure. Third, there were limits imposed on judicial review of agency decisions – courts were not to interfere unless the agency acted in an arbitrary or capricious manner.

In this spirit, the FPC was transformed into an agency with the power to set rates for the wholesale prices of electricity and natural gas sold or transported in interstate commerce. Thus the Federal Power Commission emerged as the first energy regulatory agency. The *Natural Gas Act* (NGA) of 1938 was the source of its expanded regulatory authority. The FPC gained the authority to set prices for natural gas in interstate commerce, and the state governments under state law set prices for natural gas in intrastate commerce. This allocation of power in effect created dual gas markets and set the stage for later problems of disparate availability and pricing of gas in the two markets.

In 1954, the FPC gained a major new rate-making power. Prior to that year, the NGA had been interpreted by the Commission to exclude the wellhead prices of independent producers from rate regulation. A 1954 U.S. Supreme Court decision, *Phillips Petroleum Co. v. Wisconsin*, extended FPC rate-making jurisdiction to independent producers selling or providing a service in interstate commerce. Given the very large number of rate adjudications with which the FPC was then faced, it first moved to rate-setting by groups on a regional basis and subsequently, in the mid-1970s, to nationwide rate-setting and rule-making for the independent producers.

Prior to the oil embargo and price shock of 1973, most energy decision-making was done at the state level, through rate-making by public utility commissions and attempts to conserve resources through good production practices. At the federal level, there had been no imperative to coordinate energy policy-making and, consequently, there was a lack of consistency in policy and regulation.

In an attempt to overcome the fragmentary nature of energy policy-making in the aftermath of the oil embargo, the Department of Energy (DOE) was created by the *Department of Energy Organization Act* of 1977. While reducing the many facets of energy jurisdiction, it did not bring them all into one department. DOE assumed virtually all of the powers of the Federal Energy Administration, the Energy Research and Development Administration, and the Federal Power Commission. DOE also assumed certain powers relinquished by the Department of Interior, the Department of Housing and Urban Development, the Department of Commerce, the U.S. Navy and the Interstate Commerce Commission.

Despite this amalgam which became the DOE, other powerful entities have input to U.S. energy policy and regulation. The Environmental Protection Agency (EPA), the Nuclear Regulatory Commission, the Department of Interior and the Department of State all have a major impact on energy policy.

Within DOE, several distinct organizations were created for specific purposes, and three of those agencies – the Federal Energy Regulatory Commission (FERC), the Economic Regulatory Administration (ERA) and the Energy Information Administration (EIA) – are of particular relevance to this study. The Federal Energy Regulatory Commission assumed most of the authority of the former FPC and gained new areas of jurisdiction. FERC took over many of the responsibilities under the *Natural Gas Act* (NGA, 1938), the *Natural Gas Policy Act* (NGPA, 1978), the *Federal Power Act* and the *Public Utilities Regulatory Policies Act* (PURPA, 1978). FERC has substantial authority to regulate the rates of oil pipelines under authorities of the *Interstate Commerce Act* transferred from the Interstate Commerce Commission to DOE. As well, FERC has limited authority to affect oil price regulations under the *Emergency Petroleum Allocation Act* (1973), through appeal of DOE orders to FERC. The Economic Regulatory Administration has residual jurisdiction to administer programs not in conflict with FERC, notably the authority to license imports and exports of natural gas. The Energy Information Administration was established to collect energy data for DOE and such information as is required by the *Energy Supply and Environmental Coordination Act* (1974) and the *Federal Energy Administration Act* (1974).

The unusual relationship between FERC and DOE is well captured in the following quotation.

> Within the DOE itself, an executive agency, significant powers are delegated to the cabinet-level office of the secretary and to executive departments under its control. At the same time DOE has under its administrative canopy an independent regulatory agency. Originally, the Carter administration had proposed the abolition of the FPC as an independent regulatory agency seeking to emasculate its authorities in the form of a three-member board, whose decisions could be appealed to the secretary of DOE. The Congress reacted unfavorably to this proposal and established FERC, or "son of FPC", retaining its status as a final decision-making body. This split of authority finally arrived at by Congress meant that decision-making responsibilities (depending on the resource involved) are likewise divided. FERC, for example, fundamentally retained rate-making authority over wellhead and pipeline rates for natural gas, but the secretary of DOE exercised control over crude-oil prices and allocation. FERC has authority to develop pipeline-specific natural-gas-curtailment plans, but the secretary of DOE was to set national curtailment priorities. Even more curious is the power FERC was granted by Congress over some decisions of the secretary regarding oil and products pricing and allocations. Neither the FPC nor the FERC had any authority to establish or enforce those regulations relating to oil-pricing matters, yet FERC became the body designated to hear appeals of the secretary of DOE's decisions on those subjects. FERC's own decisions are final and are reviewable by the court; they are not reviewable by the secretary as originally envisioned under the Carter plan. Not only did FERC retain its independent status in this fashion, FERC also has a veto power over actions by the secretary that may significantly affect any function within the jurisdiction of FERC... (Tomain and Hollis, 1983, p. 27-28)

It is misleading, therefore, to think of FERC simply as the American analogue of Canada's National Energy Board. Although there are parallels in their regulatory responsibilities, FERC's powers are more broadly based and the Commission's degree of independence is different.

C. FERC Rule-making

FERC has generated a large body of rules in its efforts to deregulate certain aspects of U.S. energy markets. Given the large volume of energy trade between Canada and the United States, not least in the natural gas sector, FERC's rule-making carries many implications for Canadian exports of energy. In this section, the Committee highlights selected FERC initiatives which bear on natural gas trade.

1. Opinion 256

No FERC action has stirred such protest in Canada as Opinion 256, its resolution of the "as billed" issue. The ruling came in a rate adjustment case involving the Natural Gas Pipeline

Company of America, which had sought to recover the cost of its imported Canadian gas on an as-billed basis.

In Opinion 256, issued December 8, 1986, the U.S. Federal Energy Regulatory Commission for the first time dealt with the merits of a two-part rate structure for imported gas. The Commission did not overturn the basic cost recovery mechanism but did deny as-billed treatment to Canadian natural gas by refusing to accept certain elements of the demand charge. The ruling came in an adjustment rate case involving Alberta gas purchased by the Natural Gas Pipeline Company of America from ProGas Limited and from Great Lakes Transmission Company. Opinion 256 reversed a May 21, 1986 initial decision by a FERC administrative law judge that Natural could recover the cost of its Canadian gas under the new, two-part rate system on an as-billed basis.

In the two years preceding this FERC action, Canadian gas exporters and American pipeline importers had been restructuring the cost recovery provisions of their international contracts. The former one-part commodity charge had been replaced by a two-part rate scheme, consisting of a demand charge and a commodity charge. In the case of Natural's contracts with ProGas and Great Lakes, the demand charge was to reflect fixed facility costs and was to be adjusted only as changes in these fixed costs actually occurred; the commodity charge was to be adjusted quarterly based on changes in a composite U.S. refiners' acquisition cost of crude oil.

FERC accepted that the introduction of a two-part rate structure was warranted and that it could not unnecessarily disturb this structure as embodied in the freely negotiated contracts, but maintained that it had the authority to assess the manner in which the particular rates were derived and to evaluate the "reasonableness" of the demand charge. FERC did not accept the demand charges put forward by Natural – finding them to be "unjust and unreasonable" – and it ordered these charges to be significantly reduced. In its ruling, FERC stated:

> ...we find no justification for American distributors and consumers to guarantee fixed cost recovery to Canadian pipelines with respect to their transportation of Canadian gas. We may not change Natural's contracts with its suppliers. But we may change Natural's demand charge to ensure that some portion of the Canadian fixed transmission costs will be at risk with respect to American distributors and consumers. Accordingly, we will require Natural to modify its demand charge to exclude therefrom all fixed costs associated with return on equity and related taxes...(FERC, 1986, p. 20)

In effect, the FERC decision forced certain charges previously included in the demand component to be transferred to the commodity charge. This causes an increase in the incremental cost of Canadian gas, making it less competitive in the United States. Under the netback pricing system which now prevails for exported gas, the FERC ruling has significant financial implications for Canadian gas producers.

Under the *Department of Energy Organization Act*, DOE received the authority to approve natural gas imports and exports from the former Federal Power Commission. Authority over the siting, construction and operation of pipeline facilities and to review rates proposed for the interstate transportation and sale of gas was transferred from the FPC to FERC. In 1984, the Secretary of Energy exercised his authority under the *Natural Gas Act* to delegate responsibility for regulating gas imports and exports to the Administrator of the Economic Regulatory Administration (ERA).

Only the ERA Administrator may review international gas contracts and authorize imports. Once ERA has approved an import arrangement, FERC cannot act in a manner inconsistent with the ERA action. ERA endorsed in principle the pass-through of a two-part rate structure, as was embodied in the Natural Gas Pipeline Company of America contracts with ProGas and Great

Lakes. Nonetheless, it is within FERC's jurisdiction to approve specific cost elements of the pass-through.

The U.S. Secretary of Energy had stated his view on the issue of as-billed pass-through in November 1985:

> The Department [of Energy] wants to reiterate its previous position that there should be no regulatory distinction between the treatment of domestic and imported gas supplies. If the as-billed principle is to be preserved, as stated in the Commission's Notice, it should be applied to imported gas as well. The Department believes the two-part rate design utilized in these new import arrangements is largely analogous to two-part rates that are accepted in domestic tariffs that recognize the costs in providing transportation over long distances. We see no rationale for denying imported gas the same treatment with regard to as-billed passthrough that is available to domestic pipelines. If the Commission has concerns about the allocation of imported gas costs between demand and commodity charges, it has sufficient authority to take the appropriate action. However, as long as the result of international contracts freely negotiated between commercial parties is reasonable and is approved by the Economic Regulatory Administration, we urge regulatory restraint in any unnecessary intrusion into private contractual matters. (FERC, 1986, p. 14)

FERC interprets this policy position to mean that "our prime consideration is, as stated by the Secretary, to ensure that there is 'no regulatory distinction between the treatment of domestic and imported gas supplies.'"

Natural Gas Pipeline Company of America purchases gas from ProGas, a Canadian gas broker, and from the Great Lakes Transmission Company. ProGas ships from Alberta to the U.S. border via two Canadian pipelines: NOVA and Foothills Pipeline Limited. Great Lakes purchases its gas from TransCanada PipeLines Limited – which moves the gas from Alberta to the U.S. border through its own facilities and through NOVA – for resale to Natural.

On March 25, 1985, Natural filed new tariffs with FERC to reflect its amended contracts for the purchase of Canadian natural gas, utilizing the new two-part rate system. This filing was examined by a FERC administrative law judge, whose function is to conduct hearings and prepare initial decisions for subsequent review by the FERC Commissioners. On May 21, 1986, the administrative law judge issued his initial decision, finding that Natural could recover the cost of its Canadian gas on an as-billed basis.

Demand charges applied by ProGas and by TCPL were negotiated with Natural. The ProGas daily demand charge was set at 50 cents per Mcf. The TCPL daily demand charge was set at 50 cents per million British thermal units (MMBtu), a charge approximately comparable to that of ProGas.

The administrative law judge dismissed the arguments of those parties intervening against Natural's application. These intervenors argued that the Natural demand charge of 50 cents per Mcf or MMBtu included non-fixed costs and NOVA's volumetric charges (that is, gathering and production fixed costs and volumetric charges should be included in the commodity charge, not the demand charge); that Natural's Canadian costs were not being allocated according to the principles applied to U.S. pipelines in domestic transactions, providing an unfair competitive advantage to Canadian exporters; that the pass-through of inappropriately high costs shifts the risks of marketability away from Natural and from the Canadian producers to Natural's customers; that the as-billed principle applies only if the Commission has approved the upstream cost classification, allocation and rate design method; and that Foothills' inclusion of all its fixed costs, including a return on equity and related taxes, in its demand charge is a direct contravention of FERC's modified fixed variable method.

The administrative law judge found instead that Natural's customers were benefitting from the renegotiated contracts, which had lowered the price of the Canadian gas; that the amount of cost shifting to Natural's customers was small; that allowing the as-billed flow-through of costs promoted the import policies of the Department of Energy with respect to Canadian gas; that most of the costs of Canadian gas included in the demand charge were indeed fixed costs; and that NOVA's transportation charges were properly included in the demand charge, even though NOVA charges a volumetric or postage stamp rate.

Starting from the position that Canadian and U.S. suppliers should compete for U.S. markets on an equal basis and that the Commission has the authority to investigate the "reasonableness" of Natural's demand charge, FERC concluded that it could not support the finding of the administrative law judge. FERC observed that Natural's demand charges were the result of negotiation, not the result of a normal demand charge calculation. The Commission further observed that both ProGas and TCPL were including all fixed costs in the demand charge – the straight fixed variable method – which it maintained was not justified as "there is no economic reason to assure pipeline profits when sales are not made". Accordingly, FERC required Natural to modify its demand charge by excluding all fixed costs associated with return on equity and related taxes. Natural was given the option of either subtracting those costs from its demand charges or calculating new demand charges using the modified fixed variable method, as domestic suppliers must do.

FERC concluded that, "We realize we have significantly reduced Natural's demand charge from the 50 cents per MMBtu or Mcf it is obligated to pay TransCanada and ProGas. We did this in the exercise of our responsibility under the [Natural Gas Act] to ensure that Canadian and domestic gas supplies are afforded equal treatment so that a pipeline's rates are just and reasonable and consumers are not subject to unjust and unreasonable rates." FERC did not make its ruling retroactive.

The Canadian Government has indicated to the United States Government that it will not seek to have FERC Opinion 256 challenged if the Free Trade Agreement is implemented.

2. *Order 436/500*

The partial wellhead decontrol of natural gas in the United States caused FERC to hold an inquiry into regulatory change needed in the new gas marketing environment. On May 30, 1985, FERC proposed changes to its regulation of natural gas pipelines in a Notice of Proposed Rulemaking (NOPR). Comments were received from several hundred parties and the Commission took these into account in its final rule-making. The result, FERC Order 436 issued October 9, 1985, is a lengthy and complicated document.

FERC stated that changes over the years in the natural gas industry required significant alteration to the regulatory framework "...to comply with the *Natural Gas Act* (NGA), the *Natural Gas Policy Act* of 1978 (NGPA), and the mandate of the court in *Maryland People's Counsel v. FERC*..."

Order 436 comprised a package of four interrelated parts: Part A, pipeline transportation; Part B, take-or-pay; Part C, an optional, expedited hearing procedure; and Part D, block billing. With regard to transportation, a simplified program providing for non-discriminatory access was put in place with the tariffs for such service to be volumetric, downwardly flexible, cost-of-service rates with time-of-service differentiation. Pipeline customers were given a conditional opportunity to modify their existing service agreements in order to reduce their contract demands for firm sales service. This customer option was available only if the pipeline agreed to be a transporter of gas for others. Pipelines were allowed to impose a reservation charge for firm transportation service.

The transportation provisions of Order 436 generally were to take effect November 1, 1985, apart for the grandfathering of certain provisions. No deadline was imposed for the pipeline companies to participate in the new transportation program. First notice by firm sales customers to exercise their conditional opportunity to reduce or convert firm sales entitlements (applicable only in those instances in which the pipeline opted to provide open access to transportation services) had to be given by February 1, 1986, to become effective September 1, 1986. This conditional option could be for up to 25% of firm gas sales in the first year. Such reductions could only be exercised once per year, and with prior notice of 150 days.

Under the take-or-pay provisions, "During a limited transition period, a rebuttable presumption of prudence would have been established for certain limited and circumscribed payments made by pipelines to extinguish all future minimum payment or purchase obligations in certain contracts. This presumption would have been available only to pipelines willing to offer non-discriminatory access to transportation service; this in turn would have given rise to an option for firm sales customers to reduce their contract demands."

An optional, expedited certification procedure was proposed for new services, facilities and operations for those pipelines willing to assume the risk of these new ventures by agreeing to specified conditions governing the proposed services. Competing certificates could be granted. Appropriate abandonment would be conditionally pre-granted to the pipeline, to be effective at the expiration of the underlying contracts, provided that the customer has an alternative provider of service. Traditional certification proceedings remained available for those pipelines seeking to impose some of the risk of their venture on other parties, in order to ensure that the risk imposed involuntarily on others is required by the public convenience and necessity.

With regard to the block billing provisions, a three-part gas rate was provided for pipeline sales gas, to preserve the benefits of "old" gas for existing firm sales customers and "...to mitigate competitive distortions resulting from the lingering effects of existing wellhead price controls." The first block would contain "old" gas; the second block would contain all other gas. All non-gas costs associated with purchasing gas were to be billed as a third charge, to be allocated between the two blocks. The phasing-in of block billing was to begin in the summer of 1986.

Order 436 was challenged in the courts, however. On June 23, 1987, the United States Court of Appeals for the District of Columbia issued its opinion in *Associated Gas Distributors v. FERC*. Although the Court generally upheld the substance of Order 436, it found problems with some components of the Order. In particular, the Court was concerned that the take-or-pay issue had not been adequately addressed. The Court also wanted to know how some FERC certificates could be grandfathered for periods as long as 10 years without violating the direction by Congress to prevent undue discrimination. The Court vacated Order 436 and remanded the matter for further proceedings. The result was an interim rule, FERC Order 500, issued August 7, 1987.

The Commission sought in Order 500 to take a series of interrelated actions to provide some relief from take-or-pay problems. The most controversial initiative was a new crediting mechanism for take-or-pay obligations, which FERC described in the folowing terms.

> In order to permit pipelines to reduce the incurrence of take-or-pay liability under their existing take-or-pay contracts because of transportation under these regulations, a producer seeking to have gas transported must offer credits against the pipeline's take-or-pay liability. The credit would operate by treating volumes of gas transported as though they were volumes of that producer's gas purchased by the pipeline under pre-June 23, 1987, take-or-pay contracts, with certain exceptions. The pipeline may apply the credit as though the volumes were purchased in the contract year in which the gas is transported or in any previous calendar year, commencing on or after January 1, 1986, in which the pipeline

> transported gas under these regulations. Requiring producers to offer these credits will enable pipelines to minimize aggravation of, and in many cases to reduce previously accrued take-or-pay liabilities under uneconomic gas purchase contracts because of transportation under Part 284 of the Commission's regulations. Where the pipeline's sales are displaced by the transportation, the take-or-pay liability incurred due to the loss of the sale will generally be offset by the credit. (FERC, 1987, p. 15)

While U.S. gas producers had generally favoured Order 436, they were outraged by the crediting mechanism proposed in Order 500, which they viewed as coming down decisively on the side of the pipeline companies. The Committee learned during its May 1988 visit to Washington that FERC was still attempting to arrive at a permanent rule to replace the interim Order 500. FERC was reportedly considering extending take-or-pay relief only to open-access pipelines. [Under FERC regulations, third-party gas carriage is optional and some U.S. pipelines have refused to open their systems.] Industry observers believe that the final Order 500 is likely to be challenged in the courts as well.

Canadian-U.S. Trade in Natural Gas

A. The Development of Canadian-U.S. Gas Trade

The sale of Canadian gas into the U.S. market has grown impressively since the 1960s. In some years, export sales of marketable gas have reached 40% of domestic production, indicating the importance which U.S. sales hold for the development of the Canadian natural gas industry. Imports of Canadian gas have typically satisfied about 5% of U.S. domestic demand in recent years.

Gas exports first surpassed the one Tcf level in 1972, thereafter peaking in 1973 at 1.03 Tcf. Sales held steady throughout the remainder of the 1970s, between about 0.9 and 1.0 Tcf, and reached a secondary peak of 1 Tcf in 1979. The early 1980s saw depressed gas exports as the regulated price for Canadian natural gas began to move out of line with prices in the U.S. market and as American demand contracted sharply. From 1980 through 1984, yearly export volumes ranged from 0.71 to 0.80 Tcf. Nonetheless, those exports earned an average of more than $C 4 billion annually over the five-year period.

Exports recovered to 0.92 Tcf in 1985 and then fell back again in 1986 as the price of oil plummeted, causing many U.S. industrial and utility users to switch from gas back to oil. During the winter of 1987-88, gas exports surged to a new monthly high as Canadian prices continued to erode. According to statistics provided by EMR, Canada's indigenous supply of natural gas (including producer consumption) in 1987 was 3.14 Tcf; marketable gas production (excluding producer consumption) was 2.77 Tcf; and exports were 0.99 Tcf. These numbers indicate that Canada exported almost 36% of its marketable gas production on average over 1987. Table 3 reviews the pipeline export of Canadian gas into the United States since 1970.

In January of 1988, gas deliveries to the United States set a monthly record of 132.9 billion cubic feet (Bcf). On an annual basis, this would be equivalent to a flow of 1.6 Tcf, very close to the maximum nominal export capacity of about 1.8 Tcf through the various pipeline interconnections. The average revenue per unit of gas shipped was $C 2.415 per Mcf and the total value of export sales in January was $C 263 million. Over the first three months of 1988, the leading exporter was Alberta & Southern with 104.3 Bcf shipped to the end of March. Pan-Alberta ran a strong second at 91.5 Bcf and TransCanada ranked third at 64.9 Bcf.

Canadian gas exports in total were up by 33% over the January-March 1988 period compared with the same three months of 1987. Revenues increased by a more modest 23%, however, as gas prices continued to decline. The wellhead spot price for natural gas in the United States is still dropping and industry observers expected this price weakening to prevail during the summer.

U.S. gas consumers in recent years have come to depend upon Canadian producers for about 5% of their gas supplies, although in some regions of the United States imported gas is a much more substantial contributor. Canadian gas is exported to the United States through four principal export points, which together represent 92% of total export capacity, and six smaller export points, which add the remaining 8% of export capacity. These export points are listed in Table 4 with the export capacity given in millions of cubic feet per day (MMcf/day).

Total pipeline export capacity amounts to 5,021 MMcf/day, corresponding to an annual nominal transmission capacity of 1.83 Tcf. In fact, because of bottlenecks, seasonal fluctuations and other factors, restrictions on transmission capability typically begin to appear when the export volume of Canadian gas reaches the level of about 1.2 to 1.3 Tcf per year.

Table 3: Pipeline Exports of Natural Gas to the United States, 1970-1987

Year	Volume (Tcf)	Average Price (Cdn$/million Btu)	Total Revenue (millions of current Cdn$)
1970	0.768	0.268	206
1971	0.903	0.278	251
1972	1.007	0.305	307
1973	1.031	0.340	351
1974	0.961	0.514	494
1975	0.949	1.151	1,092
1976	0.954	1.694	1,616
1977	0.995	2.040	2,028
1978	0.883	2.480	2,190
1979	1.001	2.904	2,889
1980	0.796	4.912	3,984
1981	0.762	5.705	4,370
1982	0.784	6.104	4,755
1983	0.712	5.598	3,958
1984	0.755	5.230	3,886
1985	0.923	4.353	4,018
1986	0.741	3.383	2,507
1987	0.990	2.600	2,574

Source: Personal communication, Matthias Schwarz, Director, Gas Exports Division, Natural Gas Branch, Energy, Mines and Resources, Ottawa, 3 June 1988.

Exports of natural gas to the United States are an important element of Canada's total merchandise trade, and the second largest component in our energy trade with the U.S. Measured in current dollars, the value of those gas exports has been as great as $4.76 billion in 1982, out of total energy exports to the U.S. valued at $11.69 billion. Even with the recent decline in gas prices, 1987 earnings from U.S. gas exports amounted to $2.57 billion.

The prevailing view in the United States is that larger volumes of natural gas will be purchased from Canada in the future. U.S. customers bought almost 1 Tcf of Canadian gas in 1987 and various American forecasts have Canadian imports ranging from 1.2 to 2.5 Tcf in the late 1990s. The delivery system would have to be expanded to accommodate the gas trade anticipated by most industry observers. It is also questionable whether Canadian productive capacity could support gas exports in the high end of that range.

Table 4: Canadian Natural Gas Pipeline Export Capacities

Export Point	Capacity (MMcf/day)	Share of Total Capacity
A. Major Export Points		
Huntingdon, British Columbia	812	16%
Kingsgate, British Columbia	1,589	32%
Monchy, Saskatchewan	1,059	21%
Emerson, Manitoba	1,165	23%
Total for Major Export Points	**4,625**	**92%**
B. Other Export Points		
Cardston, Alberta	141	3%
Niagara, Ontario	124	2%
Fort Francis, Ontario	35	1%
Windsor, Ontario	35	1%
Cornwall, Ontario	35	1%
Oaksburg, Quebec	26	–
Total for Other Export Points	**396**	**8%**
Total Pipeline Export Capacity	**5,021**	**100%**

Source: Arthur Anderson & Co./Cambridge Energy Research Associates, *Natural Gas Trends*, 1987-88 Edition, Chicago/Cambridge, Massachusetts, 1987, p. 120.

B. The Iroquois Pipeline Proposal

The Iroquois Gas Transmission System is a proposal to deliver Western Canadian gas into the northeastern United States, via a 24-inch pipeline extending from the TCPL trunk line at Morrisburg, Ontario to a terminus on Long Island in New York State. Although this region is already served by three U.S. pipeline systems, it lies at the end of these systems where there is the least amount of flexibility in serving the market. New England in particular has suffered deep supply constraints during previous U.S. gas shortages and is looking for enhanced security of supply.

The northeastern U.S. is divided into some 40 gas franchises, with 24 companies holding 92% of the market. These 24 distributing companies have formed a consortium to coordinate gas supply and transportation capability. Their first joint project was Boundary Gas, organized in 1979. Phase II of the Boundary project, involving 15 of the 24 companies, was subsequently certificated and gas began flowing in 1988. The Niagara export point is a serious bottleneck, however, and the consortium approached TCPL to find a new means of delivering Canadian gas into the northeastern U.S.

TransCanada PipeLines would be a 50% owner of the system, with U.S. utilities owning the other half. The Canadian suppliers for the initial gas requirement – 393.5 MMcf/day – would be Western Gas Marketing Ltd., ProGas, ATCOR and the Alberta Energy Company. The NEB granted the gas export licences in 1987 and approved the facilities application in 1988. In the United States, however, Iroquois sponsors have had little success with the regulatory process.

To avoid FERC jurisdiction in selling the gas, the Iroquois participants created a Canadian entity so that the distribution companies would not be in the position of reselling the gas in the U.S. Nonetheless, Iroquois still requires a FERC facilities licence to construct the pipeline system. Iroquois applied to FERC in April 1986, under its so-called expedited certification process. FERC subsequently decided that the project was too extensive to qualify for the expedited process, and did not schedule a hearing. The Iroquois project is vigorously opposed by many American pipeline companies and FERC declared an "open season" for competing applications to service this market. The open season filing attracted a large number of proposals and FERC has told the applicants to bring forward a smaller number of joint, rationalized proposals for its consideration. It appears that the process of finally selecting a proposal will go on for a considerable time yet.

C. The Free Trade Agreement

The Canada-U.S. Free Trade Agreement was agreed to in principle on October 3, 1987 and is scheduled to come into force on January 1, 1988, assuming that implementing legislation has been adopted by both countries prior to that date. This Agreement would eliminate many of the barriers to trade in goods and services between Canada and the United States.

Chapter Nine of the Agreement covers bilateral energy trade. The energy provisions of the Free Trade Agreement apply to coal and coal gas; crude oil and petroleum products; natural gas; uranium; electricity; liquefied petroleum gases – propane, butane and ethane; and several primary petrochemicals – ethylene, propylene, butylene and butadiene. Natural gas is not specifically mentioned in any of the stipulations in the FTA, but is covered by the general provisions applying to energy commodities.

At the time that the Committee was completing its analysis of gas deregulation and marketing, the U.S. implementing legislation for the Agreement was not available. Before making any observations regarding the potential impact of the Agreement on the Canadian natural gas sector and on the future operation of the National Energy Board, the Committee needs to study and compare the Canadian and U.S. pieces of legislation.

Appendix A
List of Witnesses

Monday, June 8, 1987: (Issue No. 10)

From Western Gas Marketing Limited:

Mr. C. Kennedy Orr, President and Chief Operating Officer
Mr. R.J. Reid, Vice-President, Canadian Sales
Mr. Barry E. Hulse, Senior Manager, Canadian Sales

From the Department of Energy, Mines and Resources:

Ms. Martha Musgrove, Director General, Natural Gas Branch
Mr. Matt Schwarz, Director, Gas Exports Division
Ms. Marie Tobin, Director, Domestic Gas Division

From the Ontario Energy Board:

Mr. Robert W. Macaulay, Chairman
Mr. John C. Butler, Vice-Chairman

Tuesday, December 1, 1987: (Issue No. 14)

From the Independent Petroleum Association of Canada:

Mr. Richard B. Hillary, General Manager
Mr. Bob Reid, Executive Director
Mr. Murray Todd, Chairman
Mr. John Schissel, Director

Tuesday, December 15, 1987: (Issue No. 15)

From the Industrial Gas Users Association:

Mr. Ted Bjerkelund, Executive Director
Mr. Robert G. Drummond, IGUA Chairman and Manager, Energy and Materials Purchasing, Polysar Ltd.
Mr. Harry Cox, Manager, Administrative Services, Cyanamid Canada Inc.
Mr. Carl Dunk, Buyer, Purchasing Department, Stelco Inc.
Mr. Jacques LaRoche, Assistant Manager of Purchase, Abitibi-Price Inc.

Monday, March 7, 1988: (Issue No. 16)

From Johnston & Buchan:

Mr. J. Thomas Brett

From Polysar Limited:

Mr. Firman J. Bentley, President, Polysar Basic Petrochemicals
Mr. Gerald Finn, Manager, Government Relations
Mr. Robert G. Drummond, Manager, Energy and Materials Purchasing

Monday, March 14, 1988: (Issue No. 17)

From the Ontario Natural Gas Association:

Mr. W.J. Cooper, ONGA Director and Senior Vice-President, Marketing and Gas Supply, Union Gas Limited

Mr. Ronald S. Lougheed, ONGA Director and Senior Vice President, Gas Supply, The Consumers' Gas Company Ltd.

Mr. Paul E. Pinnington, Managing Director

From the National Energy Board:

Mr. Roland Priddle, Chairman
Mr. Robin Glass, Executive Director
Mr. John Klenavic, Secretary
Mr. Ken Vollman, Director General, Pipeline Regulation
Dr. Peter Miles, Director General, Energy Regulation
Mr. Stan Ironstone, Director, Gas Branch
Miss Sandra Fraser, General Counsel
Mrs. Ann Sicotte, A/Assistant Secretary, Communications

From TransCanada PipeLines Limited:

Mr. J.M. Cameron, President, Pipeline Division
Mr. C. Kennedy Orr, President and Chief Operating Officer, Western Gas Marketing Ltd.
Mr. A.A. Douloff, Vice-President, Transportation

Appendix B
List of Briefs Received

The Committee also received the following written submissions:

ENERGY, MINES AND RESOURCES, DEPARTMENT OF
Ottawa, Ontario

INDEPENDENT PETROLEUM ASSOCIATION OF CANADA
Calgary, Alberta

INDUSTRIAL GAS USERS ASSOCIATION
Ottawa, Ontario

INSTITUTE FOR POLICY ANALYSIS, UNIVERSITY OF TORONTO
Toronto, Ontario

IROQUOIS GAS TRANSMISSION SYSTEM
Shelton, Connecticut, U.S.A.

JOHNSTON & BUCHAN
Ottawa, Ontario

NATIONAL ENERGY BOARD
Ottawa, Ontario

NOVA SCOTIA, GOVERNMENT OF
Halifax, Nova Scotia

ONTARIO, GOVERNMENT OF
Toronto, Ontario

ONTARIO NATURAL GAS ASSOCIATION
Toronto, Ontario

POLYSAR LIMITED
Sarnia, Ontario

QUEBEC, GOVERNMENT OF
Quebec, Quebec

WESTERN GAS MARKETING LIMITED
Calgary, Alberta

Appendix C
Committee Travel

The Senate Committee on Energy and Natural Resources made two visits to Washington, D.C. during the course of its study. The first objective of these visits was to assess the state of natural gas deregulation in the United States, particularly in view of the impact of U.S. regulatory decision-making on Canadian imports of natural gas. The second objective was to acquire an up-to-date picture of U.S. gas supply and demand, including American assessments of the need for that country to import Canadian natural gas in the future. Finally, the Committee wanted to hear U.S. opinions on the energy component of the Free Trade Agreement and on the prospects for Congress ratifying the Agreement.

Committee Visit to Washington, D.C., October 12-15, 1987

Congressional Research Service

Richard Rowberg, Chief, Science Policy Research Division
Joseph Riva, Jr., Senior Specialist, Science Policy Research Division
Lawrence Kumins, Specialist, Energy Policy, Science Policy Research Division

Department of State

John Ferriter, Deputy Assistant Secretary of State for Energy and Resources Policy, Bureau of Economic and business Affairs
William Weingarten, Deputy Director, Office of Energy Producing Countries Affairs
Norman Olsen, International Economist, Office of Energy Producing Countries Affairs

Federal Energy Regulatory Commission

Charles G. Stalon, Commissioner
Catherine C. Cook, General Counsel
Christopher J. Warner, Deputy General Counsel
Richard O'Neill, Director, Office of Pipeline and Producer Regulation
Douglas R. Bohi, Director, Office of Energy Policy
Raymond A. Beirne, Deputy Director, Office of Pipeline and Producer Regulation
A. Karen Hill, Legal Advisor to the Chairman (Gas)
Kevin P. Madden, Policy Advisor to the Chairman

Brady and Berliner

Roger Berliner, Attorney and Managing Partner
John Jimison, Attorney

Canadian Embassy

Jock Osler, Minister (Public Affairs)
William Dymond, Minister–Counsellor (Commercial)
D'Arcy McGee, Counsellor (Energy)
Jonathan Fried, First Secretary (Congressional Relations)
Ronald Wall, First Secretary (Energy)

American Gas Association

Robert B. Kalisch, Director of Natural Gas Supply

Natural Gas Supply Association

Nicholas J. Bush, President

Staff of the Subcommittee on Energy and Power of the House of Representatives Energy and Commerce Committee

Shelley N. Fidler, Assistant to the Chairman for Policy
Thomas R. Runge, Counsel
Larry B. Parker, Professional Staff Member

Department of Energy

William F. Martin, Deputy Secretary
Richard Williamson, Associate Deputy Assistant Secretary for International Affairs
Marshall Staunton, Administrator, Economic Regulatory Administration
Helmut Merklein, Administrator, Energy Information Administration
Lawrence Pettis, Deputy Administrator, Energy Information Administration
Charles Teclaw, Director, Division of Natural Gas
Connie Buckley, Director of Natural Gas, Economic Regulatory Administration
Scott O. Campbell, Director, Office of Policy, Planning and Analysis
Kathleen L. Deutsch, International Economist, Office of International Affairs
Andrea Waldman, International Economist, Office of International Affairs

Dickstein, Shapiro & Morin

Frederick Lowther, Attorney

Exxon Corporation

Judd Miller, Vice-President, Natural Gas
Donald E. Smiley, Vice-President, Washington Office

Jensen Associates

James Jensen, President

Committee Visit to Washington, D.C., May 15-18, 1988

Canadian Embassy

Leonard H. Legault, Deputy Chief of Mission and Minister (Economic)
Jonathan Fried, First Secretary (Congressional Relations)
Ronald Wall, First Secretary (Energy)

Department of Energy

David B. Waller, Assistant Secretary of Energy for International Affairs and Energy Emergencies
Robert A. Reinstein, Director, Energy and Natural Resource Trade Policy, Office of the United States Trade Representative
Chandler J. Van Orman, Acting Administrator, Economic Regulatory Administration
Connie Buckley, Director of Natural Gas, Economic Regulatory Administration
Cliff Tomaszewski, Deputy Director of Natural Gas, Economic Regulatory Administration
Charles Teclaw, Director, Office of Electricity, Coal, and Nuclear Policy and Acting Director, Natural Gas, Office of Policy, Planning and Analysis
Craig Bamberger, Assistant General Counsel for International Affairs, Office of the General Counsel
James White, Assistant General Counsel for Natural Gas and Mineral Leasing, Office of the General Counsel
John R. Brodman, Director, Office of International Energy Analysis
David Pumphrey, Director of Energy Assessments, Office of Energy Assessments
Mark Rodekohr, Chief of Demand Analysis and Forecasting, Energy Information Administration
Edward J. Flynn, Chief of Supply Analysis and Integration, Energy Information Administration
Kathleen Deutsch, International Economist, Office of Energy Assessments
Andrea Waldman, International Economist, Office of Energy Assessments
Ken Malloy, Office of Natural Gas and Economic Analysis

American Gas Association

Michael I. German, Vice President for Planning and Analysis

Vinson & Elkins

Sheila S. Hollis, Attorney and Partner

McHenry & Staffier, P.C.

John R. Staffier, Attorney and Partner

Federal Energy Regulatory Commission

Anthony G. Sousa, Commissioner
William S. Scherman, Senior Legal and Policy Advisor to the Chairman
A. Karen Hill, Legal Advisor to the Chairman (Gas)
Catherine C. Cook, General Counsel
Christopher J. Warner, Deputy General Counsel
Susan J. Court, Associate General Counsel for Gas and Oil
Robert Fitzgibbons, Associate General Counsel for Electric and Hydro Litigation
Barry M. Smoler, Deputy Assistant General Counsel, Pipeline Certificates
J. Steven Herod, Director, Office of Electric Power Regulation
Richard P. O'Neill, Director, Office of Pipeline and Producer Regulation
Raymond A. Beirne, Deputy Director, Office of Pipeline and Producer Regulation
Richard N. Foley, Office of Pipeline and Producer Regulation
Laura Bateman, Administrative Assistant to the Chairman
Kathleen Card, Staff Assistant to the Chairman for Special Projects

Staff of the Senate Committee on Energy and Natural Resources

Elizabeth A. Moler, Senior Counsel
Lisa Vehmas, Professional Staff Member

Department of Energy

David B. Waller, Assistant Secretary of Energy for International Affairs and Energy Emergencies
Robert A. Reinstein, Director, Energy and Natural Resources Trade Policy, Office of the United States Trade Representative
Chandler L. Van Orman, Acting Administrator, Economic Regulatory Administration
Connie Buckley, Director of Natural Gas, Economic Regulatory Administration
Cliff Tomaszewski, Deputy Director of Natural Gas, Economic Regulatory Administration
Charles Teclaw, Director, Office of Electricity, Coal, and Nuclear Policy and Acting Director, Natural Gas, Office of Policy, Planning and Analysis
Craig Bamberger, Assistant General Counsel for International Affairs, Office of the General Counsel
James White, Assistant General Counsel for Natural Gas and Mineral Leasing, Office of the General Counsel
John R. Brodman, Director, Office of International Energy Analysis
David Pumphrey, Director of Energy Assessments, Office of Energy Assessments
Mark Rodekohr, Chief of Demand Analysis and Forecasting, Energy Information Administration
Edward L. Flynn, Chief of Supply Analysis and Integration, Energy Information Administration
Kathleen Deutsch, International Economist, Office of Energy Assessments
Andrea Waldman, International Economist, Office of Energy Assessments
Ken Malloy, Office of Natural Gas and Economic Analysis

American Gas Association

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Vinson & Elkins

Sheila S. Hollis, Attorney and Partner

McHenry & Staffier, P.C.

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Robert Fitzgibbons, Associate General Counsel for Electric and Hydro Litigation
Barry M. Smoler, Deputy Assistant General Counsel, Pipeline Certificates
J. Steven Herrod, Director, Office of Electric Power Regulation
Richard P. O'Neill, Director, Office of Pipeline and Producer Regulation
Raymond A. Beirne, Deputy Director, Office of Pipeline and Producer Regulation
Richard N. Foley, Office of Pipeline and Producer Regulation
Laura Bateman, Administrative Assistant to the Chairman
Kathleen Card, Staff Assistant to the Chairman for Special Projects

Staff of the Senate Committee on Energy and Natural Resources

Elizabeth A. Moler, Senior Counsel
Lisa Vehmas, Professional Staff Member

Appendix D

Abbreviations and Acronyms Used in the Report

AGA	American Gas Association (United States)
CGA	Canadian Gas Association
CPA	Canadian Petroleum Association
DOE	Department of Energy (United States)
EIA	Energy Information Administration (United States)
EMR	Energy, Mines and Resources, Department of
EPA	Environmental Protection Agency (United States)
ERA	Economic Regulatory Administration (United States)
ERCB	Energy Resources Conservation Board (Alberta)
FERC	Federal Energy Regulatory Commission (United States)
FPC	Federal Power Commission (United States)
FTA	Free Trade Agreement
GSC	Geological Survey of Canada
LDCs	local distribution companies
LNG	liquefied natural gas
LPG	liquefied petroleum gases
NEB	National Energy Board
NEP	National Energy Program
NGA	*Natural Gas Act* (1938) (United States)
NGL	natural gas liquids
NGPA	*Natural Gas Policy Act* (1978) (United States)
NGSA	Natural Gas Supply Association (United States)
OEB	Ontario Energy Board
PUB	Public Utilities Board (Alberta)
PURPA	*Public Utilities Regulatory Policies Act* (1978) (United States)
R/P	reserves-to-production ratio
TCPL	TransCanada PipeLines Limited
TOPGAS	take-or-pay gas
WGML	Western Gas Marketing Limited

Appendix E
Terminology

A. Terminology Pertaining to Pipeline Tolls, Tariffs and Operations

Subject to minor modification, definitions adopted by the National Energy Board are used in this category.

Bumping: Refers to the situation where a short-term customer's service is terminated because the pipeline company requires capacity for new, long-term firm service.

Bypass: A pipeline facility which is constructed by an end user of natural gas and connected to a main transmission line, in order to bypass the local distribution system.

Commodity charge: A charge applied to volumes of natural gas actually taken by a customer in order to recover the variable costs of a pipeline.

Common carrier: A carrier who provides transportation for remuneration without discrimination among customers. Service must normally be provided on demand when capacity is available.

Contract carrier: A carrier who provides transportation for remuneration for customers who have contracted for the service over a specific period.

Contract demand service: A firm (non-interruptible) sales service for gas up to a specific maximum daily quantity. The buyer must pay a monthly demand charge regardless of the volume of gas taken and a commodity charge for the volume actually taken.

Core market: A general term referring to residential, commercial and small industrial natural gas customers who do not have alternate fuel flexibility.

Cost of service: The total cost of providing service, including operating and maintenance expenses, depreciation, amortization, taxes, cost of debt and a return on equity. Generally, the cost of service of a pipeline is the same as its "revenue requirement".

Cross subsidization: (a) Charging tolls which favour one class of customers at the expense of another; or,

(b) The provision of financial support to a company's non-regulated activities by its regulated operations, or vice versa.

Demand charge: A monthly charge which recovers the fixed costs of a pipeline. The demand charge is based on the customer's firm daily contracted volume and is payable regardless of actual volumes taken.

Double demand charge: The double payment of a pipeline company's demand charges. This occurs when a customer, who previously purchased gas through a distributor, arranges an alternate supply through a direct purchase. The customer pays the demand charges associated with its transportation service and is required by the distributor to pay the demand charges associated with the volumes which have been displaced. [The National Energy Board's operating demand methodology solved this problem.]

Fixed Costs: Costs that remain, at least in the short run, relatively constant and do not vary with throughput. Examples of fixed costs are interest expense, depreciation charges and property taxes.

Fixed toll: A unit toll which is based on forecasts of costs and throughputs for a test year, and which does not vary with changes in pipeline throughput or expense variances.

Incentive rate of return: A variable rate of return that increases to reward a pipeline company for increased efficiency.

Incremental transportation cost: The variable cost of transporting an additional unit of throughput.

Interim toll order: An interim toll order authorizes a company to charge specified tolls on an interim basis until a final order is made, usually following a hearing. Revised tolls may, at the discretion of the regulatory body, be made applicable from the date the interim tolls became effective.

Interruptible service: An interruptible gas transportation service, provided under contract, which is available when there is unused or excess capacity on the pipeline.

Laterals: Laterals are pipelines that tie into a trunk line and are generally part of either a gathering or a distribution system.

Netback pricing: The price the producer receives, which is equal to the price at the city-gate minus the transportation toll.

Open access: Refers to a customer's unrestricted access to a pipeline company's transportation services.

Operating demand volume: A demand volume approved for toll purposes, which normally is the contracted demand volume minus the demand volumes displaced by direct purchases in a distributor's franchise area.

Peaking service: A gas sales service provided under contract by a pipeline company during the winter season. The service is not subject to curtailment or interruption, and includes a take-or-pay provision.

Peak shaving: The use of LPG/LNG fuels or natural gas from storage to meet system demand during peak-use periods.

Postage stamp rate: For pipelines, a toll that is charged per unit transported regardless of distance, as in postage.

Rate base: The rate base is the amount of investment on which a return is authorized to be earned. It usually consists of plant in service, plus an allowance for working capital. This is sometimes referred to as a "net asset rate base". Other types of rate bases include a "liability rate base", which consists of debt and equity capital, and an "equity rate base", which includes only the equity component.

Return on rate base: The return which a regulated company earns on its approved rate base.

Self-displacement: Generally occurs when a distributor replaces any portion of its presently contracted firm supply with an alternate supply, or makes any other arrangement that accomplishes the same end.

Take-or-pay: A contract provision whereby a purchaser agrees to pay for a specified volume of natural gas during a given period, whether or not the contracted deliveries are taken.

Tariff: The terms and conditions under which the services of a pipeline are offered or provided, including the tolls, the rules and regulations, and the practices relating to specific services.

Toll: The amount charged by a pipeline company for the provision of transportation services.

TOPGAS: Two agreements under which TOPGAS Holdings Ltd. and TOPGAS Two Inc. assumed TCPL's outstanding take-or-pay liabilities.

T–service: A firm (non-interruptible) transportation service for gas up to a specific daily quantity. The shipper must pay a monthly demand charge regardless of the volumes actually taken.

Trunk lines: Trunk lines are the main transportation lines of a pipeline system.

Unbundling: The separation of gas sales and gas transportation services in order that customers have the opportunity to choose between "transportation" of their own gas or the full sales service of the pipeline company and distributor.

Variable costs: Costs that vary with pipeline throughput; for example, compressor fuel costs for gas pipelines.

Variable cost-of-service toll: A toll which varies from month to month to reflect actual expenses and throughput. Rules prescribed by the regulator specify which costs can be recovered, the accounting principles to be followed in determining the costs, the rate of return allowed on the investment in rate base, depreciation rates, and other parameters.

B. Terminology Pertaining to Natural Gas Resources and Reserves

Subject to minor modification, the definitions adopted in this section are taken from the September 1987 report of the House of Commons Standing Committee on Energy, Mines and Resources, entitled *Oil – Scarcity or Security?*

Raw gas: Natural gas in its natural state, existing in a reservoir or as produced from a reservoir and prior to processing. Natural gas at the wellhead usually consists of methane with decreasing amounts of heavier hydrocarbons. Raw gas may also contain such nonhydrocarbon gases as carbon dioxide, hydrogen sulphide, nitrogen, hydrogen and helium.

Marketable gas: Raw gas from which natural gas liquids and nonhydrocarbon gases have been removed or partially removed by processing. Marketable gas is also known as "pipeline quality gas" or "sales gas".

Associated gas: Natural gas in a free state in a reservoir and found in association with crude oil under initial reservoir conditions.

Non-associated gas: Natural gas in a free state in a reservoir, but not found in association with crude oil under initial reservoir conditions.

Solution gas: Natural gas that is dissolved in crude oil under initial reservoir conditions and that comes out of solution at atmospheric pressure and temperature.

Dry gas: Natural gas composed predominantly of methane and ethane.

Wet gas: Natural gas containing propane and butanes, sometimes in amounts as great as 50% or more.

Resource: All natural gas accumulations either known or inferred to exist. That portion of the resource base which has been found is referred to as **discovered resources or reserves**. That portion of the resource which is inferred to exist but not yet discovered is known as **undiscovered resources or potential reserves**.

Reserves: That portion of the resource that has been discovered, of which part is recoverable in current economic and technical circumstances and part is not.

Established reserves: Those reserves recoverable under present technology and under present and anticipated economic conditions, specifically proved by drilling, testing or production; plus that portion of contiguous recoverable reserves judged with reasonable certainty to exist based upon geological, geophysical and similar information. The term "established" to describe reserves has been adopted in Canada, and replaced the combined categories of **proved and probable reserves** previously defined by the Canadian Petroleum Association.

Initial volume in place: The gross volume of raw natural gas calculated or interpreted to exist in a reservoir before any volume has been produced.

Initial established reserves: Established reserves prior to the deduction of any production.

Remaining established reserves: Initial established reserves less cumulative production.

Ultimate potential: An estimate of the initial established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard to the geological prospects of the area and anticipated technology and economic conditions. Ultimate potential includes cumulative production, remaining established reserves, and future additions to reserves through extensions and revisions to existing pools and the discovery of new pools.

Developed reserves: Proved reserves considered recoverable through existing wells.

Undeveloped reserves: Economically recoverable reserves considered to exist in proved reservoirs and which will be recovered from wells drilled in the future.

Connected reserves: Natural gas reserves connected to a pipeline.

Unconnected reserves: Natural gas reserves which are not connected to the market.

Reservoir: A porous, permeable sedimentary rock containing commercial quantities of crude oil and/or natural gas.

Pool: A natural underground reservoir containing an accumulation of crude oil and/or natural gas separated, or appearing to be separated, from any other such accumulation.

Field: A certain geographical area from which crude oil and/or natural gas is produced, or a particular underground producing zone. A field may contain one or more pools linked by some common element, such as their lying along the same trend or their being a product of a common geographical disturbance.

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Respectfully submitted,

Earl A. Hastings
Chairman

MINUTES OF PROCEEDINGS

WEDNESDAY, SEPTEMBER 7, 1988
(52)

The Standing Senate Committee on Energy and Natural Resources met at 9:00 a.m. this day in camera, the Chairman, the Honourable Senator Earl A. Hastings, presiding.

Members of the Committee present: The Honourable Senators Balfour, Hastings, Lefebvre and Olson. (4)

The Committee, in compliance with the Order of Reference dated 1st April 1988, resumed its examination of the production and use of natural gas in Canada, with particular reference to natural gas deregulation, or any matter relating thereto.

It was–
Ordered, that the Committee proceed to meet in camera.

The Honourable Senator Lefebvre moved that, notwithstanding the resolution dated 22nd June 1988, the title of the Twelfth Report be: "Natural Gas Deregulation and Marketing".

The question, being put on the motion, it was--
Resolved in the affirmative.

At 9:15 a.m., the Committee adjourned to the call of the Chair.

ATTEST:

Timothy Ross Wilson

Clerk of the Committee