NATURAL GAS MARKET ASSESSMENT

Long-term Canadian Natural Gas Contracts: AN UPDATE

National Energy Board
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ACQ	Annual Contract Quantity
ATQ	Annual Trigger Quantity
B.C.	British Columbia
Bcf	billion cubic feet
BC Gas	BC Gas Inc.
CWNG	Canadian Western Natural Gas Company Limited
DCQ	Daily Contract Quantity
FERC	Federal Energy Regulatory Commission
GIC	Gas Inventory Charge
GJ	gigajoule
LDC	Local Distribution Company
MMcf/d	million cubic feet per day
NEB	National Energy Board
NIT	NOVA Inventory Transfer
NOVA	NOVA Gas Transmission Limited
NSD	No Self-Displacement
NUL	Northwestern Utilities Limited
NYMEX	New York Mercantile Exchange
ODV	Operating Demand Volume
PGT	Pacific Gas Transmission Company
Tcf	trillion cubic feet
TCGS	TransCanada Gas Services Ltd.
TCPL	TransCanada PipeLines Limited
U.S.	United States
WACOG	Weighted Average Cost of Gas
$10^6m^3/d$	million cubic metres per day

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INTRODUCTION

As part of its ongoing monitoring of the Canadian natural gas market, the National Energy Board ("NEB") published a report entitled the Natural Gas Market Assessment: Long-Term Canadian Natural Gas Contracts in August 1992 (the "1992 Report"). That report analyzed the changes and trends that occurred in the structure of the contractual chain as well as the terms and conditions of long-term contracts governing the sale of western Canadian gas into domestic and export markets between the commencement of deregulation in the mid-1980's and the end of 1991.

Prior to deregulation in 1986, the contractual chain by which most western Canadian gas reached end-users was through a supply aggregator, which was often also a major pipeline such as TransCanada PipeLines Limited ("TCPL"), and demand aggregators such as U.S. interstate pipelines and Canadian local distribution companies ("LDCs"). The relationships between buyers and sellers, defined by these contracts, were relatively inflexible.

Deregulation of natural gas markets and prices in Canada and the U.S. in the mid-1980's allowed new players to compete in the marketplace and provided them with assured access to pipeline transportation capacity. These new entrants, such as end-users, cogenerators, and producer/marketers, brought with them new and different contracting practices. The entry of new players and the emergence of a competitive marketplace also required the traditional supply and demand aggregators to change their contracting practices.

The important trends in contracting practices that emerged during the five years after deregulation was initiated in late 1985 included:

- Increased flexibility for both buyers and sellers under the contract, which enabled both parties to respond more readily to changing demand and supply conditions. This flexibility was expressed in terms of more flexible supply commitments (e.g. the widespread use of corporate warranties to secure supply as compared to dedicated reserves) and less onerous purchase obligations (e.g. the use of gas inventory charges and deficiency payments rather than take-or-pay to secure market performance);

- Greater balance between the buyers' and sellers' respective obligations under the contract lead to more stable contractual relationships;

- Shorter contract terms allowed parties to adjust sooner to unanticipated changes in the natural gas industry. In the mid-1980's, the term of a typical gas contract was 20 to 25 years. By the early 1990's, there was a clear trend toward terms of 10 years or less;

- As a result of buyers and sellers seeking to diversify their supply portfolios and market outlets, the number of long-term contracts increased sharply, while at the same time, the average Daily Contract Quantity ("DCQ") declined;

- Contract pricing terms had become simpler and more market sensitive; and,
- The availability of unbundled transportation service on major pipeline systems resulted in a wider range of contracting options and choices, particularly with respect to delivery points. Many buyers elected to purchase western Canadian gas at upstream delivery points, such as Empress, Alberta, and to hold the downstream pipeline capacity.

The changes occurred most rapidly in the central Canadian markets where the traditional demand aggregators, or LDCs, were responding to the rapid increase in direct purchase activity that occurred in the late 1980's. Many changes were also reflected in contracts to serve the U.S. Northeast, which at the time represented a new market opportunity for western Canadian gas. In other market regions where direct purchase by end-users was not a major factor, such as the Alberta/Saskatchewan and U.S. Midwest markets, changes were occurring more slowly. The structure of contracts serving other market regions where access to pipeline capacity was limited, such as California, was also slow to change.

Since 1991, there have been several important events in the gas industry that have lead to further changes to the terms and conditions contained in long-term contracts. These events include:

i) The U.S. Federal Energy Regulatory Commission's ("FERC") Order 636, which was issued in 1992. This Order fully unbundled the sales and transportation services offered by U.S. interstate pipelines. U.S. pipeline companies ceased to be gas merchants and began to terminate their long-term contractual arrangements with western Canadian suppliers. As a result, some of the gas volumes that were previously supplied to interstate pipelines were recontracted to U.S. LDCs;

ii) The increased ability of the buyers and sellers to purchase and deliver under spot sales contracts as well as the increased liquidity of western Canadian spot markets beginning in 1993, reduced the need for buyers to enter into long-term contracts to secure gas supplies and markets;

iii) The maturity and competitiveness of U.S. spot markets and more recently the spot markets for western Canadian gas have induced parties to index the price of gas traded under long-term contracts to spot prices;

iv) The increase in the liquidity of the NYMEX gas futures[1] market and the emergence of Over-the-Counter[2] markets for financial products such as "swaps"[3] has enabled parties to more effectively manage the price risks associated with long-term contracts;

v) The NEB's decision in early 1995 to allow pipeline capacity to be traded by shippers at market clearing rates in the secondary market (i.e. the removal of the price cap); and,

vi) More recently, the unbundling of gas markets behind the city-gate of many U.S. LDCs will likely result in increased direct purchases by end-users in several markets. It may also mean that LDCs in certain jurisdictions will cease to be natural gas merchants.

[1] A gas future is a contract to either buy or sell a fixed quantity of gas at a basing point, such as Henry Hub, LA., during a specific month in the future (e.g. September 1997).

[2] The Over-the Counter market for natural gas is an informal, unregulated market in which buyers and sellers trade gas for future delivery at major points throughout North America other than Henry Hub, LA.

[3] A swap is a financial arrangement where parties agree to exchange or swap one type of cash flow for another, based on a fixed price for a cash flow based on a monthly market price over a fixed period of time.

The purpose of this Update is to identify the significant changes that have occurred since 1991 in long-term contracts (i.e. having an initial term of five years or longer), including both new contracts executed since 1991 as well as the changes that have been made to the long-term contracts that were in effect in 1991 in response to these events. This report was prepared by Peter J. Milne & Associates in association with Board staff.

The Update is based on an analysis of a database of almost 200 long-term contracts maintained by Peter J. Milne & Associates Inc. (See Appendix A for a complete listing of contracts surveyed.) Compared to the 1992 Report, the total volume of gas under long-term contracts as measured by the DCQ has declined by 23 percent to 159 $10^6m^3/d$ (5.6 Bcf/d), although the total number of contracts has increased slightly (unless otherwise noted, all references to volumes in this study are in terms of DCQs). The contracts included in the survey represent the first arm's-length or primary sale[4] between a party representing producer interests and a party representing consumer interests. The survey includes most export contracts that have been filed with the NEB as of May 1996.

The primary focus of this Update is on contract terms and conditions. It does not focus on contract performance such as actual gas flows or prices. In a small number of cases, gas has not yet begun to flow under the contract; either the parties are waiting for pipeline capacity to be installed or in other instances all the necessary regulatory approvals have not been received.

Sellers have been categorized into three groups: traditional supply aggregators that were active prior to deregulation (e.g. ProGas Ltd.); new supply marketers (e.g. Direct Energy Marketing Limited); and producer/marketers (e.g. Shell Canada Limited) that sell directly to end-users and demand aggregators.

Buyers have also been divided into three groups: Canadian and U.S. LDCs; cogenerators and electric utilities; and downstream marketing companies (e.g. Coastal Gas Marketing Co.). Electric utilities, such as New England Power Company, have not yet become a major purchasing group; consequently, the few contracts negotiated to date have been included with the cogeneration contracts.

Chapter 2 of the report analyzes the change(s) in the structure of long-term contracts and transportation arrangements between buyers and sellers since 1991. It documents the impact that the withdrawal of U.S. interstate pipelines from their traditional merchant function has had on long-term contracts for Canadian gas and the continuing trend towards shorter-term and smaller-volume contracts.

Chapter 3 discusses the important trends that have emerged since the early 1990's with respect to pricing and pricing indices used by parties to long-term gas contracts. Chapter 3 also identifies the trends in the detailed terms and conditions of natural gas agreements over the past five years and examines the mechanisms used to secure the buyers' contractual obligations to purchase gas and the sellers' commitments to deliver gas compared to earlier periods.

Chapter 4 summarizes the key conclusions and identifies the important differences between domestic and export contracting patterns.

[4] A primary contract is defined as the first arm's-length agreement between a seller or seller's agent and the first buyer as an end-user or the end-user's agent.

TRENDS IN THE STRUCTURE OF LONG-TERM CANADIAN NATURAL GAS CONTRACTS

By the early 1990's, fundamental changes had occurred in the traditional contracting regime for long-term gas that prevailed prior to natural gas deregulation in the mid-1980's. New players, such as producer/marketers and cogenerators, emerged in the marketplace while other players, such as the traditional supply and demand aggregators, were playing a smaller role in the market for long-term gas. These changes were documented in the 1992 Report.

The purpose of this Chapter is to illustrate the extent of the changes in contract structure since 1991 and to identify the emerging trends in long-term contracting practices that will likely prevail into the next century.

2.1 Purchasers

Prior to deregulation in 1985, the major purchasers of Canadian gas under long-term contracts were Canadian LDCs, U.S. interstate pipelines and a small number of U.S. LDCs. Between 1985 and 1991, cogenerators emerged as new purchasers of western Canadian gas under long-term contracts. Since 1991, U.S. interstate pipelines gradually ceased to be purchasers of Canadian gas. In the new environment, U.S. gas marketers are emerging as new purchasers of Canadian gas under long-term contracts. Figure 2-1 illustrates the relative share of long-term Canadian gas contracted by market segments.

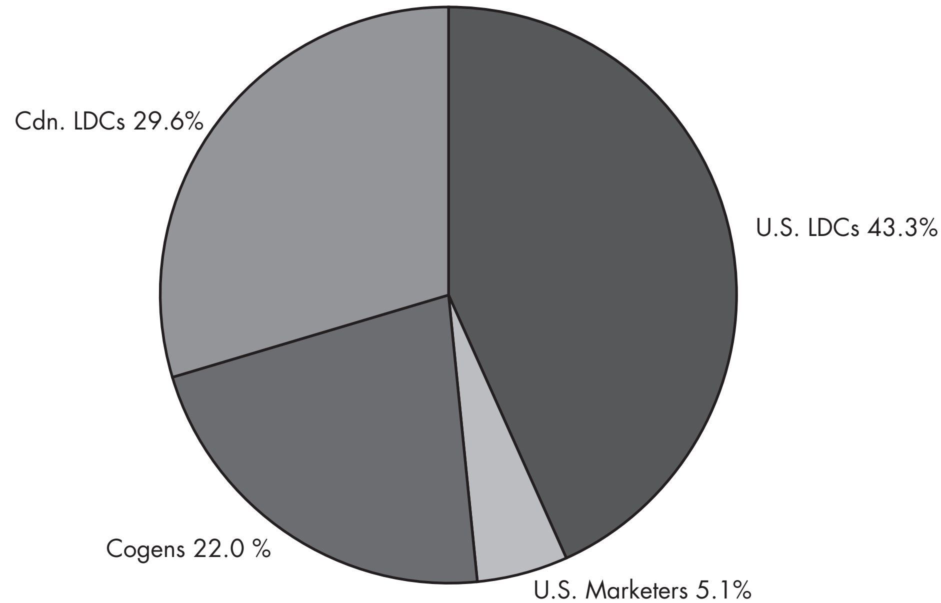
The current importance of each of the different types of buyers is assessed below.

2.1.1 U.S. Interstate Pipelines

Until the early 1990's, the major U.S. purchasers of western Canadian gas under long-term contracts were U.S. interstate pipelines. The U.S. interstate pipelines would resell Canadian gas to U.S. LDCs served by their systems. In 1991, there were 17 long-term, large volume contracts totalling 60 $10^6m^3/d$ (2.1 Bcf/d) with U.S. interstate pipelines, representing 45 percent of the volume of Canadian gas contracted to the export market. Many of the contracts had been in effect since the 1960's and had served as the foundation for much of the Canadian natural gas industry.

F I G U R E 2 . 1

Purchasers of Canadian Gas Under Long-term Contracts in 1995



In 1992, in response to FERC Order 636, U.S. interstate pipelines phased out their merchant function to become open access carriers. Consequently, the long-term contracts with these pipeline companies have been allowed to expire or were terminated prior to their expiry date.

The withdrawal of U.S. interstate pipelines from their merchant function has had the greatest impact on the U.S. Midwest market where long-term contracts with several interstate pipelines, totalling 31 $10^6 m^3/d$ (1.1 Bcf/d), have been terminated. Similarly, the longstanding, large volume contract (22 $10^6 m^3/d$ or 775 MMcf/d) between Alberta and Southern Gas Co. Ltd. and its parents Pacific Gas Transmission Company ("PGT") and Pacific Gas and Electric Company was terminated in 1993 in response to pressure from the California Public Utilities Commission.

2.1.2 U.S. Local Distribution Companies

In several instances, gas that was originally contracted to U.S. interstate pipelines has been recontracted under long-term arrangements directly to U.S. LDCs served by the interstate pipelines. Of the 60 $10^6 m^3/d$ (2.1 Bcf/d) that has been decontracted by the interstate pipelines, approximately 19 $10^6 m^3/d$ (680 MMcf/d) was recontracted directly to U.S. LDCs, primarily in the U.S. Midwest. None of the volumes formerly contracted to California through PGT have been recontracted on a long-term basis to California LDCs.

Today, U.S. LDCs as a group are the largest single purchaser of Canadian gas under long-term contracts accounting for 69 $10^6 m^3/d$ (2.4 Bcf/d) or 43 percent of the total volume of Canadian gas committed under long-term agreements. However, given the growing pressure on these LDCs to unbundle their services and facilitate the direct purchase of gas by end-users, it is not anticipated that many new long-term contracts with U.S. LDCs will be negotiated and significant amendments may be necessary to existing contracts to respond to the changing circumstances within the LDC markets.

2.1.3 Canadian Local Distribution Companies

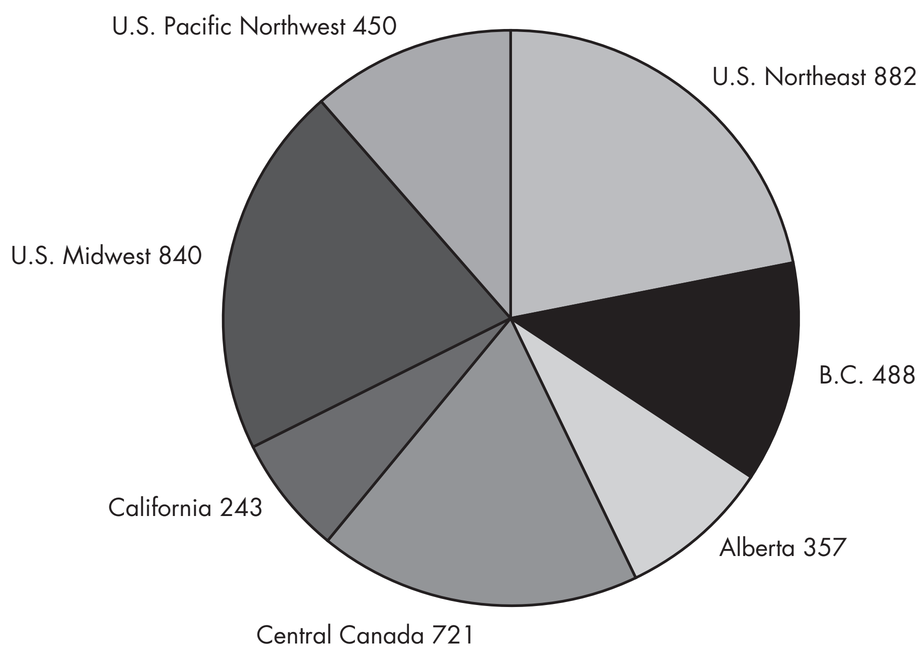
Throughout the three major Canadian gas markets, British Columbia, Alberta/Saskatchewan and central Canada, the major purchasers of gas under long-term contracts have been and continue to be LDCs on behalf of their system gas customers[5].

The LDCs that serve central Canada restructured their long-term gas supply portfolios in the late 1980's and early 1990's and have only executed a few new, small volume contracts since 1991. In 1991, western Canadian gas under contract to this market totalled 33.2 10^6m^3/d (1.2 Bcf/d). By the end of 1995, this volume had been reduced to approximately 20.4 10^6m^3/d (720 MMcf/d) through the Operating Demand Volume[6] ("ODV") adjustment mechanism in response to direct purchase activity by marketers and end-users.

The total volume of gas contracted to Canadian LDCs under long-term contracts is shrinking as the merchant activities of the LDCs decline and as LDCs turn to shorter-term contracts to meet their incremental gas supply requirements. In part as a result of provincial initiatives in deregulating gas, BC Gas restructured and diversified its gas supply portfolio by entering into 21 long-term contracts totalling approximately 13.8 10^6m^3/d (488 MMcf/d) which replaced its long-term gas supply contract which was due to expire. There have been few changes to the structure of the LDC's portfolio over the past five years. The two major LDCs serving the Alberta market, Canadian Western Natural Gas Company Ltd. ("CWNG") and Northwestern Utilities Ltd. ("NUL"), had approximately 13.3 10^6m^3/d (470 MMcf/d) under long-term contract in 1991.

F I G U R E 2 . 2

Canadian Gas Contracted Long-term to LDCs in 1995 (MMcf/d)



5 System gas customers are defined to be end-users that rely on the LDC to supply their gas requirements under regulated rate schedules.

6 Operating Demand Volume adjustment is a contract term that allows the buyer to adjust the DCQ downward on a periodic basis (e.g. monthly) by an amount equal to a pro rata share of the volumes displaced in a market region during the period by direct purchase activity.

Many of these contracts were negotiated in the 1970's and have expired in recent years. CWNG and NUL have been replacing the gas with shorter-term contracts and today, the two utilities have approximately 10.2 $10^6m^3/d$ (360 MMcf/d) remaining under long-term agreements. Figure 2-2 shows the amount of Canadian gas under long-term committment to the various LDC markets.

2.1.4 Cogeneration Plants

Beginning in 1985, a major new market emerged for western Canadian natural gas as independent power producers constructed a large number of cogeneration plants throughout North America, particularly in the U.S. Northeast and U.S. Pacific Northwest.

By 1991, almost 30.7 $10^6m^3/d$ (1.1 Bcf/d) of Canadian gas was contracted on a long-term basis to U.S. cogeneration plants and a small number of electric generating plants. Almost 70 percent of the gas was destined for cogeneration plants in the U.S. Northeast pursuant to some 30 contracts.

Since 1991, most of the growth in the cogeneration sector has occurred in the U.S. Pacific Northwest, where 14 new long-term contracts totalling 5.7 $10^6m^3/d$ (200 MMcf/d) have been executed. During this time, the pace of cogeneration development has slowed in the U.S. Northeast. Only four new long-term contracts have been executed with cogenerators, totalling approximately 2.8 $10^6m^3/d$ (100 MMcf/d). Moreover, a number of contracts have been cancelled or terminated in the past few years as a result of decisions to cancel or postpone the construction of several northeastern cogeneration plants. Today, there is approximately 20.3 $10^6m^3/d$ (715 MMcf/d) contracted to U.S. Northeast cogeneration plants.

Canadian cogenerators are not a major market for long-term western Canadian gas. In central Canada, there are nine cogeneration plants that have 4.2 $10^6m^3/d$ (145 MMcf/d) of gas under long-term contract (these contracts are not in the public domain). Most of these contracts were executed in the early 1990's. Gas-fired cogeneration has not been developed on a large scale in either the B.C. or the Alberta markets.

2.1.5 U.S. Gas Marketers

In the early 1990's, the first contract with a U.S. marketer was negotiated between Shell Canada Limited and Enron Gas Marketing, Inc. Recently, U.S. marketing companies have emerged as a significant new type of buyer for western Canadian gas under long-term contracts. In 1994 and 1995 alone, nine long-term contracts totalling approximately 8.1 $10^6m^3/d$ (285 MMcf/d) were executed for resale in the U.S. Midwest and Northeast markets to LDCs and end-use customers. In some instances, U.S. marketers have contracted for gas that was released when a contract with a U.S. interstate pipeline was terminated. In other circumstances, the marketers represent new incremental markets.

2.2 Sellers

The two major types of sellers under long-term contracts are the traditional supply aggregators[7] and individual producers. In addition, there is a small group of marketers that have aggregated a supply pool to sell on a long-term basis. There has been little change in these three groups since the early 1990's.

[7] Traditional supply aggregators were the principal marketers of Canadian natural gas prior to deregulation in 1985. While most of these organizations still exist today, they have undergone major reorganizations in response to market developments over the last decade.

2.2.1 Traditional Supply Aggregators

The traditional supply aggregators (Pan-Alberta Gas Ltd., ProGas Limited, TransCanada Gas Services Limited (formerly Western Gas Marketing Limited) and Westcoast Gas Services Inc.) held most of the contracts with the U.S. interstate pipelines. As these contracts were terminated over the past few years, the traditional aggregators experienced a significant drop in the volume of gas under long-term contract. In 1991, the traditional aggregators had 125.4 $10^6m^3/d$ (4.4 Bcf/d) contracted under long-term agreements. By 1995, the total volume had declined almost 40 percent to 77.5 $10^6m^3/d$ (2.7 Bcf/d). As shown in Figure 2-3, most of the sales made by the traditional supply aggregators are now made to U.S. LDCs and, to a lesser extent, Canadian LDCs.

2.2.2 Natural Gas Producers

Following deregulation in the mid-1980's, several producers entered the marketplace and sold gas under long-term contracts directly to Canadian and U.S. LDCs and cogeneration plants. In 1991, producers had committed 64.5 $10^6m^3/d$ (2.3 Bcf/d) under long-term contracts. As a result of contract cancellations and displacements under LDC operating demand volume mechanisms, the total volume committed by producers on a long-term basis declined to 46.9 $10^6m^3/d$ (1.7 Bcf/d). Figure 2-4 illustrates that producers have executed the majority of their long-term contracts with Canadian LDCs and cogenerators.

FIGURE 2.3

Long-term Supply Aggregator Contracts in 1995

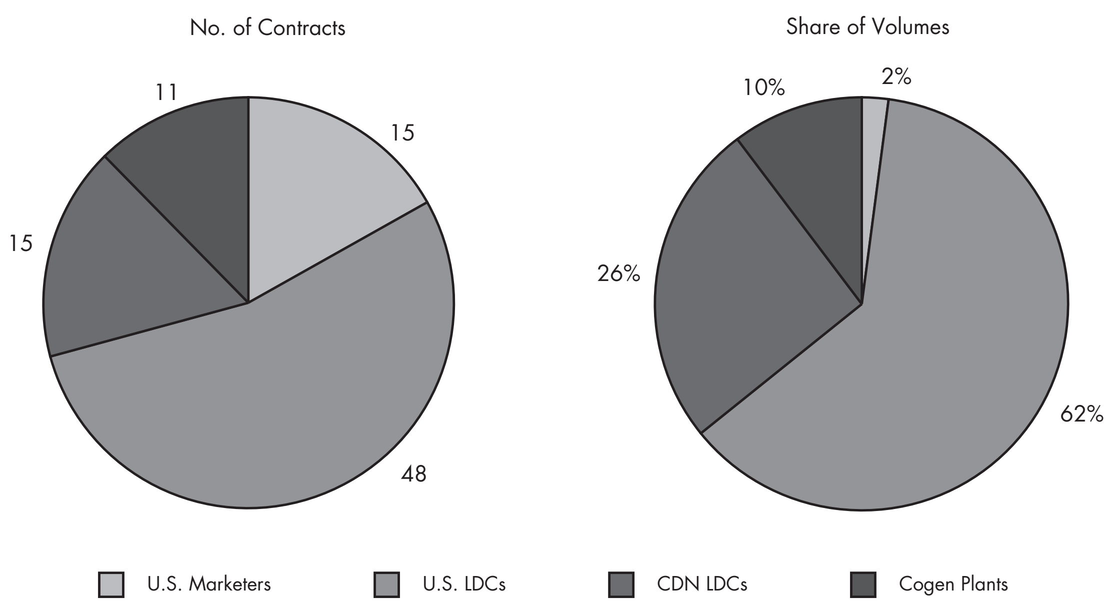
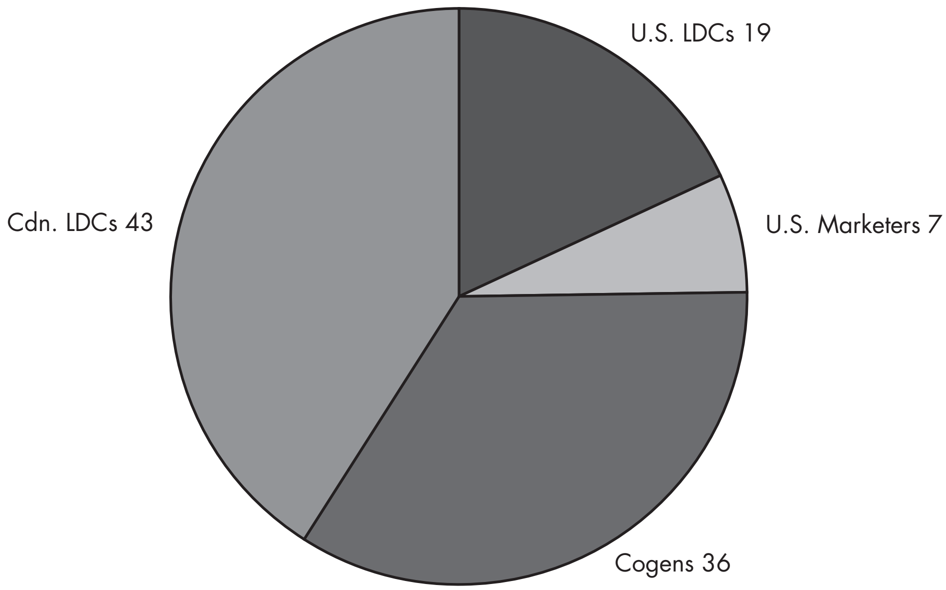


FIGURE 2.4

Long-term Producer Contracts in 1995



2.2.3 Canadian Natural Gas Marketers

Natural gas marketers play a role similar to the traditional supply aggregators except that they have tended to be smaller and most emerged after deregulation in 1985. These marketers have a relatively small amount of gas contracted under long-term agreements. In 1995, they had 10.9 $10^6m^3/d$ (385.7 MMcf/d) under long-term contract compared to 9.2 $10^6m^3/d$ (322 MMcf/d) in 1991.

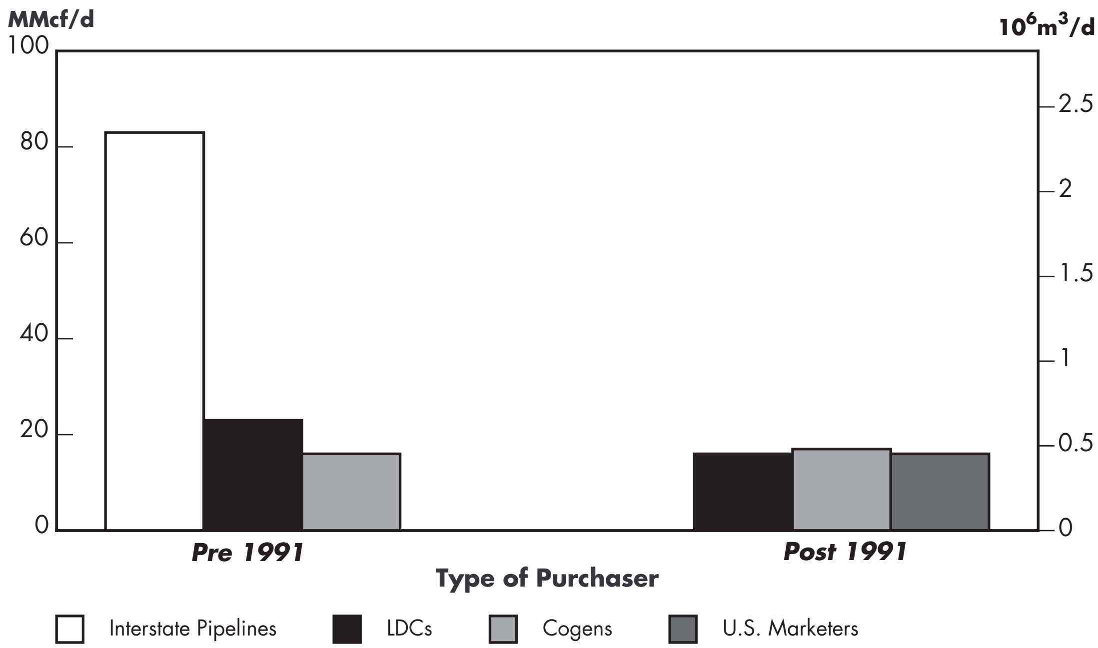
2.3 Size of Long-term Contracts

The exit of U.S. interstate pipelines, which served as large demand aggregators for western Canadian gas, has resulted in a sharp decline in the average size of long-term agreements. Prior to deregulation when the interstate pipelines were the largest buyers of long-term gas, the average contract size was 3.5 $10^6m^3/d$ (125 MMcf/d). Between 1985 and 1991, many smaller buyers, such as U.S. LDCs and cogenerators, entered the marketplace and the average contract size declined to 1.2 $10^6m^3/d$ (41 MMcf/d). The trend towards smaller contracts has continued, primarily as a result of a thirty percent decrease in the average contract size for LDCs. The average size of all long-term contracts negotiated since 1991 is 0.5 $10^6m^3/d$ (16 MMcf/d).

Figure 2-5 illustrates that the average size of contracts negotiated with LDCs has continued to decline while the size of contracts with cogenerators has remained stable.

FIGURE 2.5

Average Contract Size-Pre vs. Post 1991



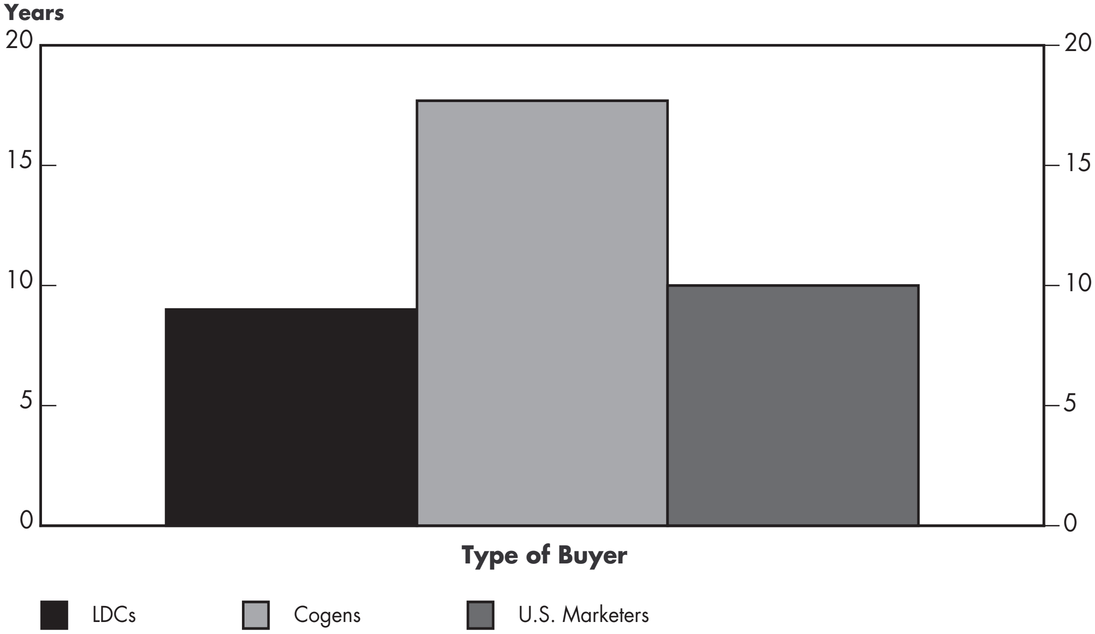
2.4 Term of Long-term Contracts

At the same time as the average contract size has been shrinking, the term of long-term contracts has been declining. In the 1970's and early 1980's, a typical long-term contract with a U.S. interstate pipeline or an LDC was 20 or 25 years as buyers attempted to secure supplies of gas in the face of potential shortages. As concerns over the adequacy of long-term gas supplies began to abate in the late 1980's, there was a trend towards shorter term contracts. By the early 1990's, the terms of most long-term contracts with LDCs were typically 10 years or 15 years in length. Contracts with most cogenerators were for 15 years, although a small number of cogeneration contracts have terms of 20 years.

The trend towards shorter-term contracts has continued since 1991, particularly among LDCs. As indicated in Figure 2-6, the average term of new LDC contracts is less than 10 years. Contracts with cogenerators continue to have terms of either 15 or 20 years, which is usually closer to the term of the financing arrangements supporting the cogeneration plant. The average length of contracts with U.S. marketers is 10 years.

FIGURE 2.6

Average Term of Long-term Contracts Negotiated Since 1991



2.5 Total Volume of Gas Committed Under Long-term Contracts

Considering the termination of long-term contracts by U.S. interstate pipelines, the maturity of the long-term contracts with Canadian LDCs and the trend towards smaller and shorter-term contracts, an important question arises as to how much western Canadian gas remains committed under long-term contracts.

Figure 2-7 indicates that over the next decade there is a sharp decline in the total volume of western Canadian gas under currently existing long-term contracts. The decline begins in earnest in the year 2000, falling to less than 13.3 $10^9m^3/y$ (470 Bcf/y) by 2007. It is expected that most of the volumes of gas that currently flow under long-term contracts will continue to flow when the contracts expire. However, given the trend away from long-term contracts, most of the gas will likely flow under shorter-term arrangements.

FIGURE 2.7

Volumes of Canadian Gas Remaining Under Long-term Contracts

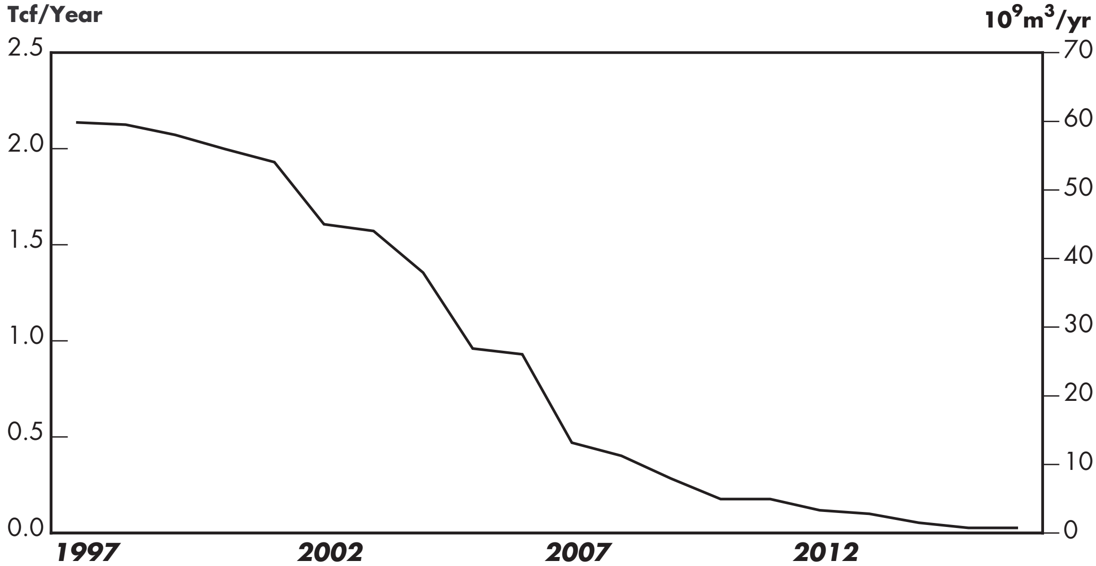
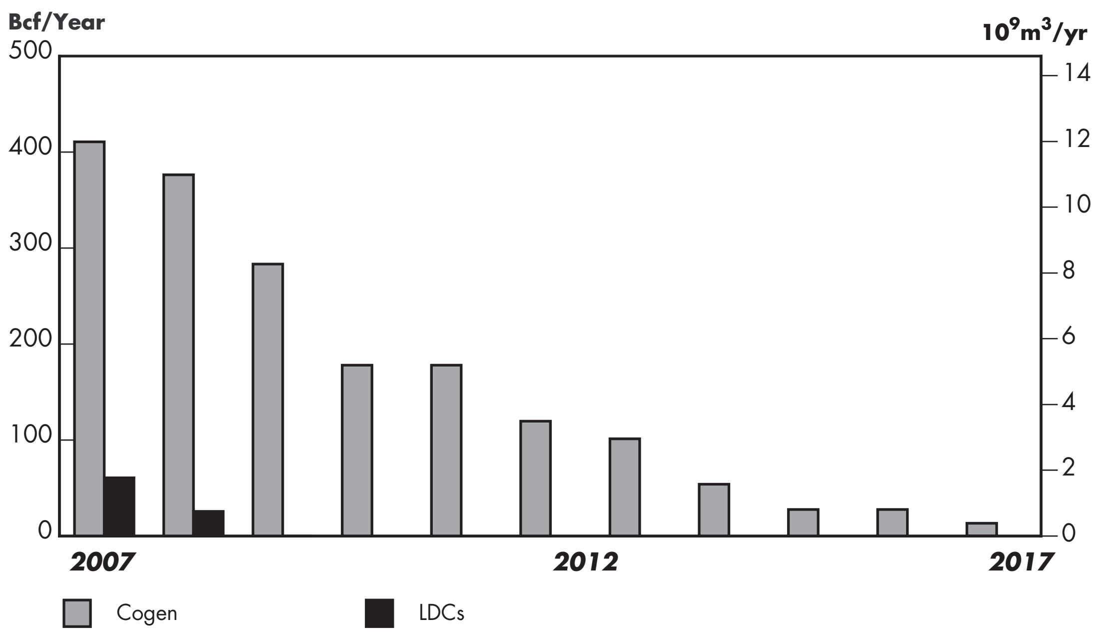


FIGURE 2.8

LDC and Cogen Contracts Post 2006



As shown in Figure 2-8, almost all the gas remaining under existing long-term contracts will be contracted to cogenerators by the year 2007.

2.6 Long-term Versus Short-term Gas Sales

Before deregulation in 1985, virtually all western Canadian gas was sold under long-term contracts. By 1990, the proportion of total gas sales that flowed under long-term contract had declined to 58 percent and by 1994, the proportion had declined further to 36 percent of total sales of 133 10^9m^3 (4.7 Tcf) as shown in Figure 2-9.

As discussed above, gas flows under long-term contracts are expected to continue to decline as U.S. LDCs face growing competition from direct sales, and buyers and sellers gain greater confidence in short-term gas markets as reliable sources of gas supplies. New long-term contracts may, however, be necessary in the future to support the construction of new pipeline capacity or if market conditions change.

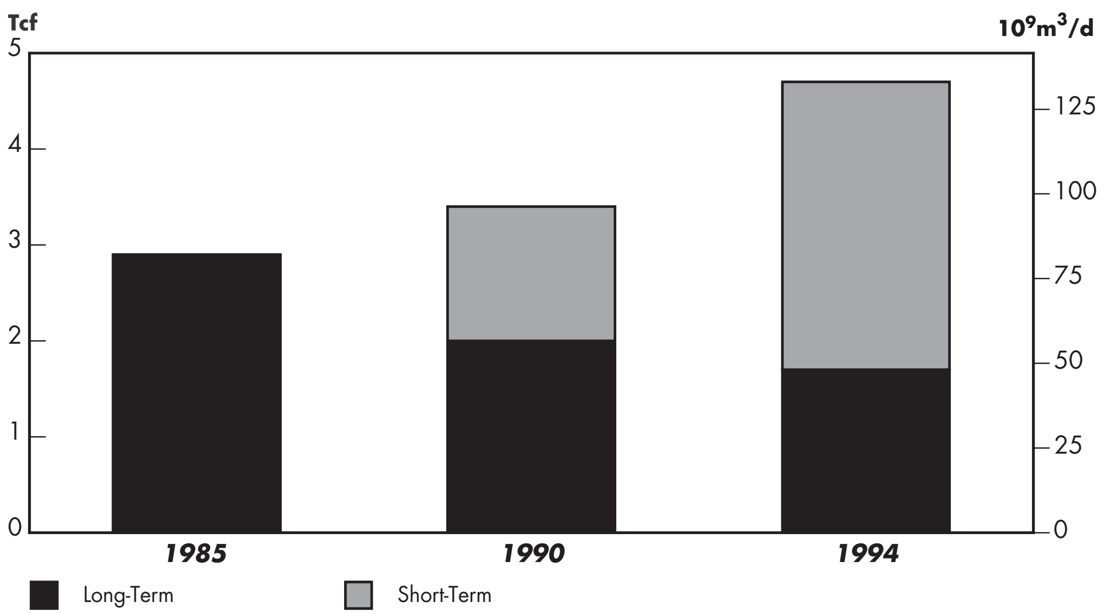
2.7 Contract Delivery Points

Prior to deregulation, the delivery point under almost all long-term contracts was downstream of the Western Canadian Sedimentary Basin. In the case of gas destined for export, the point of sale was the export point on the Canada/U.S. border at the interconnect with a U.S. interstate pipeline. For domestic sales, the point of sale was almost always an LDC city-gate.

In 1988, the central Canadian LDCs broke with this practice and contracted to purchase their long-term gas supplies at Empress on the Alberta/Saskatchewan border at the inlet to the TCPL system. These LDCs hold the TCPL capacity from Empress to their respective franchise areas. In the small number of contracts that these LDCs have negotiated since the early 1990's, they have maintained the practice of contracting at Empress, although some interest has been expressed

FIGURE 2.9

Long-term Contracts vs. Short-term Gas Sales



in changing the delivery point to AECO 'C'[8] or as a NOVA Inventory Transfer ("NIT")[9], given the greater market liquidity at this point.

BC Gas also holds much of the capacity on the Westcoast pipeline required to serve its market, although in many cases it has assigned the capacity to its suppliers. The two major utilities in Alberta are shifting to AECO 'C' or an equivalent delivery point, such as the storage site at Carbon, Alberta near Calgary, under many of their long-term supply contracts.

Unlike Canadian LDCs, U.S. LDCs do not purchase Canadian gas at upstream delivery points. U.S. LDCs have always, with few exceptions, purchased western Canadian gas at the export point on the Canada/U.S. border and this practice has not changed during the 1990's. Part of the explanation for this practice is that when gas that was contracted to U.S. interstates was recontracted to LDCs, the sellers (usually supply aggregators) held the pipeline capacity to the export point. However, even in circumstances where the sale to the LDC represents an incremental market, the typical delivery point continues to be the export point on the Canadian border, regardless of whether the supplier is a producer or a supply aggregator.

A large number of U.S. Northeast cogenerators that contracted for western Canadian gas on a long-term basis between 1988 and 1991 also negotiated to purchase gas at Empress and to hold the capacity downstream of the point of purchase. By purchasing the gas at Empress, the commodity price of gas used for dispatching the cogeneration plant could be maintained at a lower level ensuring that the plant would be dispatched at a higher load factor. The willingness of the cogenerator to hold the pipeline capacity also made this market sector attractive to individual producers marketing gas directly on a long-term basis. Virtually all of the long-term cogeneration and electrical generation contracts supplying plants in the U.S. Northeast or California with an Empress or Coleman delivery point are supplied by independent producers.

In the case of all cogeneration plants in the U.S. Pacific Northwest that are being supplied with B.C. gas via the Westcoast pipeline system, the delivery point under the contract is a point on the Canada/U.S. border such as Huntingdon, B.C.

Long-term sales to U.S. marketers, a relatively new market for long-term gas, have a range of delivery points, the most common point being an upstream point such as Empress, Alberta. Other long-term contracts with U.S. marketers have downstream delivery points beyond the Canada/U.S. border such as Ventura and Harper, Iowa on the Northern Border system.

8 AECO "C" is a gas storage site adjacent to the NOVA Gas Transmission system, 100 km. west of Empress.

9 A NOVA Inventory Transfer is an exchange or transfer of title of gas that has been received into the NOVA pipeline system but not yet delivered to a connecting pipeline.

TERMS AND CONDITIONS OF NATURAL GAS CONTRACTS

The primary purpose of most long-term contracts governing the sale of western Canadian natural gas has been to secure a reliable supply of gas for the buyer, often at a delivery point at or near the buyer's facilities and to secure a long-term market outlet for the seller. The terms and conditions of long-term contracts are often customized to meet the particular requirements of both buyers and sellers as well as their perception of the risks involved and the market conditions at the time the contract is negotiated.

The past five years have witnessed only modest changes in the terms and conditions securing the buyers' obligation to purchase under long-term contracts. There have been almost no changes in the mechanisms used to secure the sellers' obligation to deliver. The aspect of long-term contracts in which there have been many important changes, not only in new contracts but also in amendments to existing contracts, is contract price.

The purpose of this Chapter is to assess the changes in pricing mechanisms used in long-term contracts as well as to identify the trends that have emerged since 1991 in the terms and conditions used to secure the buyers' obligation to purchase and the sellers' commitment to deliver.

3.1 Long-term Contract Prices

Prior to 1986, the price of almost all Canadian natural gas was regulated by governments. When gas prices were deregulated in 1986, the lack of markets and market information posed a major challenge for parties to long-term agreements faced with negotiating the contract price.

Prior to 1992, the price of gas exported to U.S. interstate pipelines under long-term agreements was typically indexed to the monthly or annual weighted average cost of gas ("WACOG") purchased from U.S. suppliers by the interstate pipeline for resale to LDCs. Long-term contracts negotiated with U.S. LDCs and cogenerators in the late 1980's typically had complex pricing formulas linking the contract price to a basket of pipeline sales rates and prices of alternative fuels such as heating oil, heavy fuel oil and sometimes coal. Other long-term contracts with LDCs, particularly Canadian LDCs, required the parties to renegotiate the contract price each year which proved to be a difficult and time consuming task given the lack of reliable market information about forward gas prices.

When FERC issued Order 636 in 1992, and as U.S. interstate pipelines gradually phased out their role as natural gas merchants, parties to a large number of long-term contracts for sales into the export market were required to revise the pricing terms of their long-term contracts. At the same time, developments in the short-term markets for western Canadian gas prompted parties such as Canadian LDCs to enter into long-term contracts with annually-negotiated prices.

Beginning in the late 1980's in the U.S. and the early 1990's in Canada, spot market prices became a reliable indicator of the price of firm gas sold over short periods of time (e.g. daily, monthly). Today, these markets are viewed as balanced, liquid and competitive. At the same time, the NYMEX futures contract has gained acceptance as a highly liquid and competitive market in which the future price of gas to be delivered over longer periods could be determined. Many buyers and sellers also want to be able to manage the price risks associated with their long-term contracts on the financial markets.

The changes in long-term contract pricing methodologies that occurred between 1992 and 1995 as a result of these events are the most important changes that have occurred to contract terms and conditions over the last five years.

As the key indices used during the 1980's and early 1990's to price long-term gas (e.g. interstate pipeline WACOGs) ceased to exist, many parties turned to spot markets and to a lessor extent the NYMEX to determine the base price of gas under long-term contracts. The base price of gas is adjusted as necessary for factors such as delivery points. The structure of the base indices and typical price adjustments are discussed below.

3.1.1 Demand Charges

Most long-term contracts involving bundled services (the commodity, natural gas plus transportation service) have a demand/commodity price structure. The demand charge is normally designed to recover from the buyer fixed costs that must be incurred by the seller regardless of actual gas flows. A demand charge component may include pipeline demand charges (e.g. NOVA, TCPL) incurred by the seller to the point of delivery, gas inventory charges, reservation fees and administration fees. Less frequently, they may also include the cost of pipeline fuel and pipeline commodity charges. The further the point of sale is from the point of production, the more significant the demand charge becomes in relation to the total contract price.

3.1.2 Commodity Charges

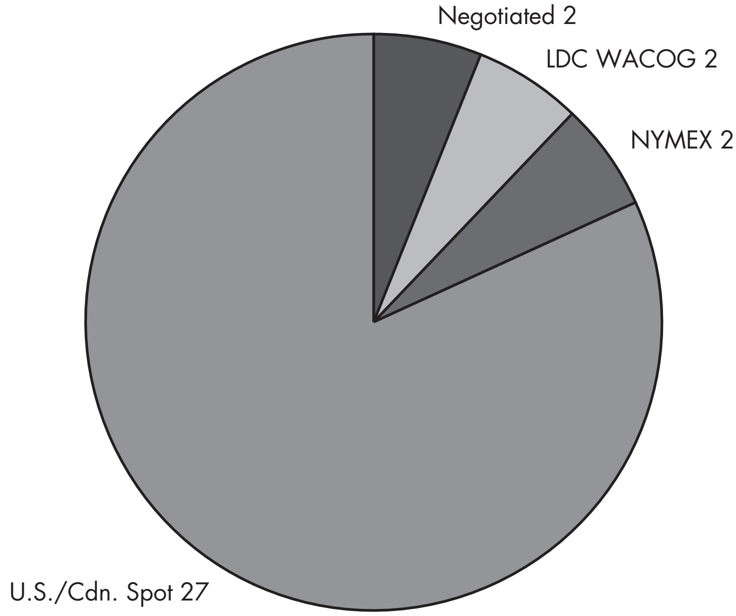
The commodity charge usually reflects the price of the natural gas itself sold under the contract and in almost all long-term contracts today it is determined periodically (usually monthly) based on spot gas prices and, to a lesser extent, fuel oil prices.

Contract commodity charges or prices for western Canadian gas can be determined in three ways: i) value in the final market, in which the commodity charge is based on the price of alternative energy sources, usually alternative gas supplies, in the buyer's market region (i.e., the buyer's alternative or avoided cost); ii) value in the supply region, where the commodity charge is based on market prices of western Canadian gas in the supply basin (e.g. at Empress, Alberta); and iii) contracts in which the buyer and seller agree, either through a formula or negotiation, on a mix between the values in the end market and the supply basin.

Figure 3-1 identifies the price drivers in Canadian and U.S. contracts executed since 1991. The large majority of these contracts are based on either U.S. or Canadian spot prices.

F I G U R E 3 . 1

Price Drivers in Canadian and U.S. LDC Contracts Executed Since 1991



Despite the changes to contract pricing terms, most contracts with U.S. LDCs and cogenerators continue to have commodity prices that are based on market value or market conditions at or near the point of consumption. Figure 3-2 shows the price drivers for U.S. LDC contracts and Figure 3-3 shows the price drivers for contracts with cogenerators.

Almost all contracts with oil prices in the index were negotiated prior to 1992 and are for sales to U.S. Northeast LDCs and cogeneration plants including the large volume contracts with the Boundary Gas, Inc. and Alberta Northeast Gas, Limited consortium of LDCs.

The commodity prices in most long-term contracts supplying domestic markets are based on market conditions in the supply basin. The large volume TCGS contracts with Consumers' Gas, Union Gas and Centra Gas Ontario and Centra Gas Manitoba are based on NYMEX prices less an Empress basis differential[10]. Prices under almost all other long-term contracts supplying central Canadian and Alberta markets are based on monthly spot prices at Empress or AECO 'C'/NIT.

Many of the long-term supply contracts between BC Gas and producers and marketers have also been amended in recent years from annually negotiated prices to prices indexed to monthly spot prices for BC Gas and NYMEX prices adjusted by the Sumas basis differential.

[10] An Empress basis differential is the market determined differential between the price of natural gas delivered to Henry Hub, LA. and the price of gas delivered at Empress quoted by financial institutions active in the Over-the-Counter Market.

FIGURE 3.2

Price Drivers Under U.S. LDC Contracts

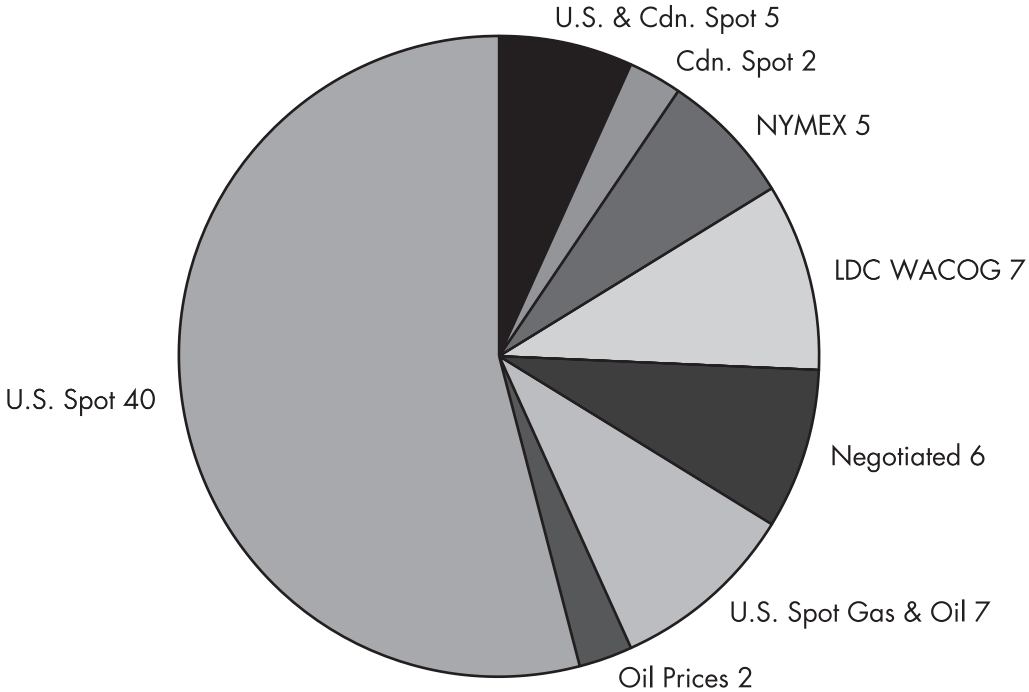
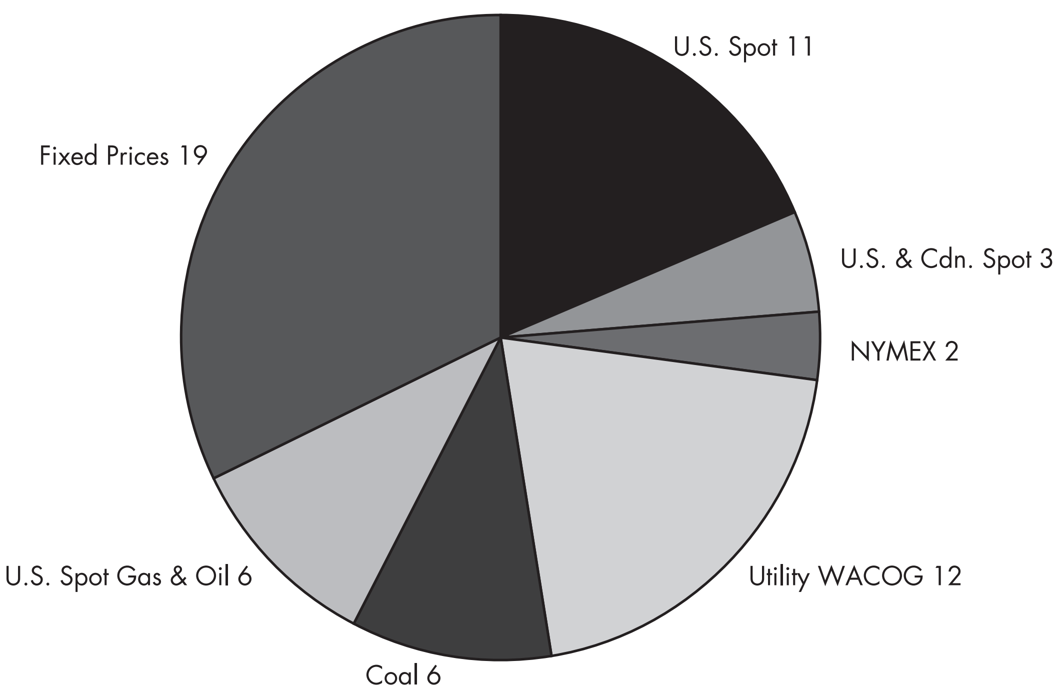


FIGURE 3.3

Price Drivers Under Congeneration Contracts



The distinction between the reference points for export and domestic contract prices is explained below:

i) Almost all long-term export contracts to U.S. LDCs are for bundled services. The point of sale is the export point, which is often near the buyer's market, allowing the seller to price against the buyer's alternatives, which in most cases is U.S.-sourced spot gas; while

ii) Domestic long-term contracts are full commodity contracts where the point of sale is in the supply basin (transportation service downstream of the basin is not provided), allowing the buyer to price against the seller's alternatives, normally Alberta and B.C. short-term or spot prices.

The commodity prices for most long-term Canadian and U.S. LDC contracts negotiated since 1991 have been designed to track either U.S. or Canadian spot gas prices in a systematic manner. There were no new contracts of any type negotiated during this period indexed to oil products or coal prices. The pricing terms of more than 40 of the contracts that were in effect in 1991 have been renegotiated to substitute spot prices for other gas prices such as WACOGs.

By indexing long-term contract prices to posted indices such as U.S. spot prices and Canadian spot prices at key market hubs, buyers and sellers can reduce the price risks; moreover, price risks can be further managed through financial derivatives such as swaps.

Most contracts today with downstream delivery points have commodity prices that are net of any demand charges paid under the contract. A typical pricing index in a long-term contract for bundled services would be:

Commodity Charge = U.S. Spot Price - Demand Charge

U.S. Spot Price-may be an average of U.S. Gulf and mid-continent spot prices quoted by the trade press

Demand Charge-may include Canadian pipeline transportation demand charges to the delivery point (e.g. NOVA and TCPL demand charges to Emerson) plus Gas Inventory Charges ("GIC")(eg. $ .10US/ MMbtu)

Full Contract Price = Commodity Charge (as above) + Contract Demand Charge

This type of contract is often referred to as a netback agreement. Netting back demand charges shifts the risk of increases in pipeline tolls to the seller. It also ensures that the gas under contract remains competitive in the buyer's market area, increasing contract load factors while protecting the seller against the risk of unabsorbed pipeline demand charges. Most contracts do not allow demand charges to be renegotiated during the term of the agreement.

3.1.3 Pricing Flexibility and Arbitration

The most effective means of ensuring both the buyer's and seller's full performance under a long-term contract and to achieve a high contract load factor, is to ensure that the contract price is market sensitive, that is, the price closely tracks both the seller's and buyer's alternatives at the delivery point.

To protect both the seller and the buyer against the risk that the pricing formula or index does not reflect the pricing objectives over the full term of the contract, most contracts specify that either party can request that the formula be renegotiated. Approximately 65% of all long-term contracts with indexed or market-based pricing terms surveyed provide for either conventional or final offer arbitration. Under final offer arbitration, each party puts forward its proposed price supported by evidence and the arbitrators must choose one of the two. Most contracts limit renegotiation and arbitration to resolution of commodity price disputes. Demand charge obligations are not normally subject to renegotiation or arbitration.

Since deregulation, the trend has been to specify detailed criteria and objectives in the contract against which arbitrators must determine a price. Also, today's contract will often specify the rules of arbitration to be followed and the location such as the B.C. Centre for International Arbitration in Vancouver.

Most contracts provide for conventional arbitration in which both parties present their position and evidence with respect to what the contract price should be and the arbitrator(s) establish a price based on the evidence presented and the objectives and criteria stated in the contract. A continuing trend in gas contracts is to specify final offer or "baseball" arbitration.

3.2 Buyer's Obligation to Purchase Gas

From the perspective of most sellers, regardless of whether they are producers or supply aggregators, the primary purpose of a long-term contract is to secure a stable and reliable outlet for a portion of their gas production or gas supply. However, unlike today's spot or short-term contracts, the buyer under most long-term contracts has not made a firm commitment to purchase full contract quantities each day of the contract. In order to ensure that high load factors will be achieved over the term of the contract, and before committing to meet the buyer's requirements on demand, sellers will typically secure the buyer's commitment or implement an incentive to purchase at least a significant proportion of the annual or monthly contract quantity.

There are two major risks that sellers face when they enter into a firm, long-term contract with a buyer. First, the possibility exists that the buyer may lose or give up its market as a result of a structural change in demand or if the buyer changes roles as a result of regulatory changes. This is what recently occurred in the U.S. when interstate pipelines discontinued their merchant function under FERC Order 636. It also occurred in Canada after deregulation in 1985 when industrial and commercial end-users elected to purchase gas directly from producer/marketers rather than from the traditional demand aggregators, such as LDCs. Further changes on both sides of the border should be anticipated if the gas marketing activities of Canadian LDCs are fully deregulated and if direct purchase becomes widespread in U.S. markets. It is difficult for sellers to effectively protect themselves against this risk through a gas sales contract and it often results in early termination of, or major changes to, long-term contracts. The second and more manageable risk is the possibility of buyers "shopping the market". This is the risk of buyers purchasing gas from other suppliers, including spot gas, usually at prices lower than the long-term contract price, before the volumes are fully nominated under a long-term contract.

There are several mechanisms that are used to establish the buyer's obligation to purchase gas in gas contracts and thereby reduce these risks, particularly the second risk. At the same time, the application of these mechanisms over the last five years recognizes that many buyers, particularly Canadian and U.S. LDCs, no longer have guaranteed or assured markets for gas purchased under long-term contracts.

3.2.1 Take-or-pay Commitments

Take-or-pay is defined for the purpose of this report as an obligation by the buyer to purchase a specific volume of gas over a defined period (eg., 60 or 80% of the Monthly Contract Quantity or the Annual Contract Quantity ("ACQ"). If the buyer fails to purchase the specified volume (assuming that the seller was able to deliver the gas) for reasons other than force majeure, it is nevertheless obligated to pay for the gas usually at the current commodity price. In effect, the buyer has prepaid for the gas and may recover the prepaid balances over at least the next two or three years and often over the remaining term of the agreement subject to the availability of transportation capacity.

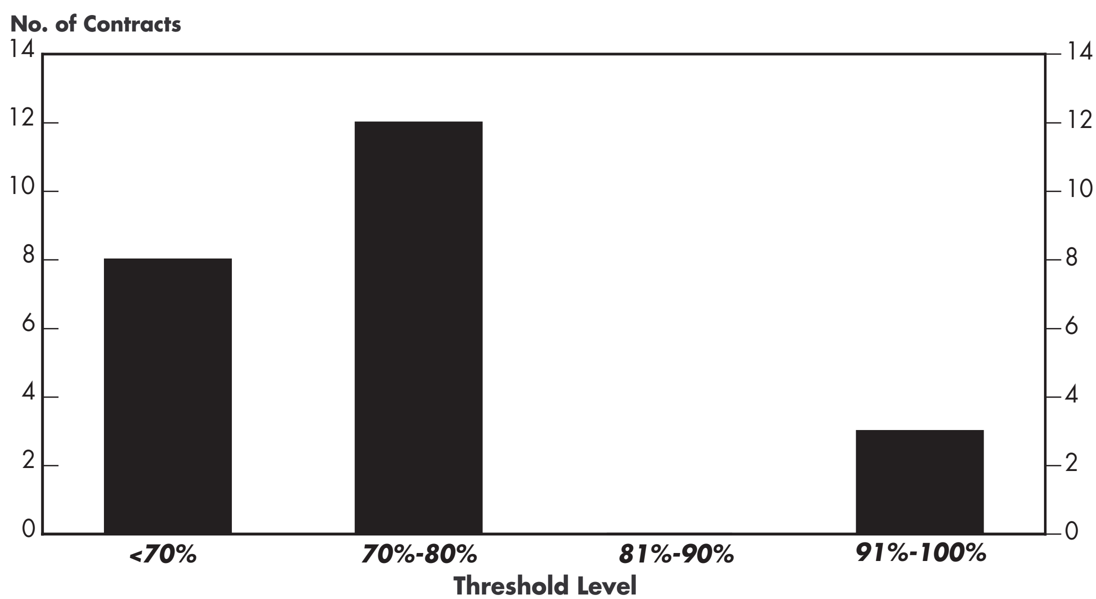
Today, no more than 25 contracts have take-or-pay clauses, compared to 55 in 1991. Of this total, only 8 contracts were negotiated after 1991, indicating a continuing trend away from take-or-pay. The contracts in the survey with traditional take-or-pay clauses are split equally between the cogeneration sector and U.S. LDCs.

Experience would suggest that take-or-pay does not protect the seller against the risk of a structural change in the industry. While take-or-pay may be an effective deterrent against the risk of the buyer "shopping the market", up to a point (i.e., up to the threshold level), it creates large risks for buyers. Given these concerns, take-or-pay is being replaced by other mechanisms such as deficiency charges.

Figure 3-4 shows the range of take-or-pay thresholds in long-term contracts.

FIGURE 3.4

Export Contract Take or Pay Thresholds



Levels below which buyer must pay for gas not nominated.

3.2.2 Deficiency Charges

A large number of long-term contracts negotiated since deregulation and particularly since 1991 require the buyer to pay a deficiency payment, reservation charge or a GIC on gas volumes not nominated. Although deficiency payments or their equivalent can be structured in different ways, they have evolved from the traditional take-or-pay mechanisms and have a similar effect without creating an unacceptable risk for the buyer. Rather than essentially being a prepayment for gas, a deficiency payment is either an explicit or an implicit recognition of a minimum level of fixed costs that the seller has incurred to be capable of meeting its contract commitments (e.g. gas field maintenance and development and transportation). Further, deficiency payments are generally not recoverable in future periods.

The effectiveness of a deficiency charge or other similar mechanisms is determined not only by the threshold level (i.e., the load factor triggering the deficiency charge) but perhaps more importantly by the amount of the charge or penalty that the buyer must pay on deficient volumes. Prior to 1991, the typical threshold volume of a deficiency payment and GICs was 60 to 75% of the ACQ. Today, as the use of deficiency charges has become more widespread, the typical threshold level that triggers a deficiency charge has increased to 80 to 100% of the ACQ. The charges are negotiated between the buyer and the seller and vary widely. In general, however, they take one of three forms: a percentage (e.g. 10 - 20%) of the current commodity price; an absolute amount or charge (e.g. $.05US - $.10US/MMbtu); or pipeline demand charges upstream of the delivery point. At least 90 contracts included in the survey include a deficiency payment, reservation charge or GIC, more than double the number of contracts in 1991.

With the emergence of highly liquid spot markets for Alberta gas, a trend appears to be to base the deficiency charge on the seller's liquidated damages. If the deficient volumes can be sold on a spot basis, the buyer must compensate the seller for any lost revenue (if any) on the sale. In effect, buyers are indemnifying the seller against lost revenues.

Over the last five years, GICs, reservation and deficiency charges have become an accepted mechanism to provide buyers with an incentive to purchase at high load factors. They are designed to assure the seller a minimum level of revenue while at the same time providing the buyer with an incentive to purchase threshold volumes of gas. They are frequently used by sellers marketing gas to all sectors, including cogens and Canadian and U.S. LDCs.

3.2.3 Pipeline Demand Charges

For many years, every long-term gas contract in which the seller held capacity on a regulated pipeline to deliver contract quantities to the point of sale, required the buyer to pay the regulated monthly demand charge for pipeline capacity held by the seller. Full pipeline demand charges were paid by the buyer, regardless of whether full contract quantities were purchased. Until the late 1980's, the seller held the pipeline capacity to the export point or, in the case of Canadian markets, to the LDC franchise. Contracts were silent regarding the disposition of unused pipeline capacity held by the seller during periods when buyers nominated less than the DCQ. During this period, the number of short-term markets were relatively small and often pipeline capacity was unutilized. As the number of short-term markets grew in the late 1980's and early 1990's, sellers were able to use capacity upstream of the delivery point to make third party sales even though buyers were paying the demand charges, which was a valuable contract feature if the point of sale was an important marketing point (e.g. Emerson, Manitoba or Niagara Falls, Ontario).

Recognizing the value of pipeline capacity today, the emergence of spot markets at major export points and the ability to trade pipeline capacity on the secondary market, buyers have become less willing to pay full pipeline demand charges on unnominated volumes. Many contracts today require the seller to credit a portion of any revenue received by the seller through the use of pipeline capacity dedicated to the contract to make third party sales or if the capacity is assigned to other parties. As part of these arrangements, the buyer often agrees to assign any unutilized capacity downstream of the delivery point to the seller to facilitate third party sales.

3.2.4 No Self-Displacement ("NSD")

As noted earlier, one of the serious risks that sellers face in a long-term contract is the potential for the buyer to "shop the market", purchasing gas from other sellers usually at prices below the contract before purchasing full contract quantities. A mechanism that has come into limited use since deregulation to address this risk is an explicit commitment by the buyer that it will not purchase incremental gas supplies before it has nominated its full contractual entitlement. In a few cases, the commitment not to self-displace is only binding if the seller's gas is competitively priced or the commitment is only limited to Canadian gas (i.e., the buyer has only committed not to purchase other Canadian gas if it has not purchased full contract quantities).

Over the last five years, fewer than ten new contracts contain a NSD clause as sellers have relied more on deficiency charges and market sensitive pricing mechanisms to prevent buyers from "shopping the market" than on commitments by buyers not to self-displace.

3.2.5 Seller's Rights to Reduce Contract Quantities

A serious risk that long-term contracts pose for sellers is the possibility that the buyer will nominate substantially below the DCQ or ACQ over an extended period of time as a result of a structural or fundamental change in the buyer's demand pattern. To provide protection against this risk, in the 1980's and early 1990's several (60 contracts) sellers to both U.S. LDCs and cogen plants negotiated the right to reduce the contract DCQ if a minimum level of gas was not nominated over a one or two year period (often referred to as an Annual Trigger Quantity or "ATQ"). ATQs enable the seller to unilaterally release gas reserves, deliverability and transportation capacity from a contract, and recontract these resources to other buyers. ATQs provide little protection against short-term risks such as the buyer "shopping the market" and have largely fallen into disuse since the early 1990's.

3.2.6 Operational Demand Volume Adjustment Mechanisms

As noted above, one of the key risks of long-term contracts for sellers is the possibility that the buyer, particularly a demand aggregator such as an LDC purchasing large volumes for resale, loses its customer base. This can occur for several reasons including loss of sales to other gas marketers, which has occurred on a large scale in markets such as central Canada since deregulation, as end-users elect to purchase gas directly from producer/marketers. For example, in Québec, 80 percent of the gas volumes are purchased directly from producers and marketers.[11]

Loss of market to direct purchase is a major risk for buyers such as LDCs, particularly if a gas supply contract includes demand charges, deficiency charges or reservation fees that must be paid

[11] Source: Gaz Métropolitain Annual Credit Review with Canadian Bond Rating Service, March 28, 1996, page 13

regardless of whether full contract quantities are taken or not. Several LDCs have protected themselves against the loss of sales and market opportunities to competitors with ODV adjustment mechanisms.

An ODV clause allows the buyer to reduce the contract quantity, either monthly or annually, by the amount in which sales have been lost to other gas marketers. The lost sales volume is normally prorated across all the buyer's long-term suppliers.

To date, ODV clauses have been used most extensively by the LDCs serving the central Canadian and B.C. markets since 1986. In the U.S., several contracts executed with LDCs serving Wisconsin and upstate New York include ODV mechanisms. It is anticipated that many U.S. LDC contracts will be amended over the next few years to include ODV or similar mechanisms as direct purchase activity increases in U.S. markets.

3.3 Seller's Commitment to Deliver

Although the changing role of LDCs as gas merchants in several jurisdictions and the emergence of dynamic and liquid spot markets have reduced the demand for long-term, secure gas supplies, buyers have purchased gas under long-term contracts to ensure that they will have a reliable and secure gas supply over an extended period of time, particularly during periods of peak demand. The obligation of the seller to deliver contract quantities is an integral part of existing long-term agreements.

Several mechanisms are used to secure the seller's commitments. The choice of mechanism depends upon the practices and policies of the buyer and seller, the type of seller, the nature of the buyer's commitment to purchase and current industry practices.

3.3.1 Dedicated Reserves

In earlier periods when alternative, firm gas supplies were not readily available in short-term markets, a major concern to buyers was that the seller would have adequate gas reserves, deliverability and pipeline transportation to be able to deliver contract quantities throughout the term of the agreement. One mechanism used by parties to reduce the risk of a supply failure was dedicated reserves, sometimes referred to as reserves-based contracts. In general, reserves-based contracts require the seller to set aside specific physical gas reserves under its control to fulfil the commitments of a gas contract. Dedicated reserves normally restrict the seller from selling gas from the reserves to third parties without the permission of the buyer.

Prior to deregulation, when almost all gas was sold to buyers through supply aggregators, the primary sales contracts between buyers and sellers were deliverability contracts that were not backed by dedicated reserves. However, as buyers began to purchase gas directly from producer/marketers in the late 1980's and early 1990's, many required the seller to dedicate specific reserves to the contract. Moreover, to secure financing, many contracts to supply U.S. cogeneration plants are based on dedicated reserves.

None of the long-term contracts for western Canadian gas executed since 1991 have been backed by dedicated reserves. There appears to be a complete shift away from this mechanism in favour of deliverability contracts backed by corporate warranties.

3.3.2 Corporate Warranties

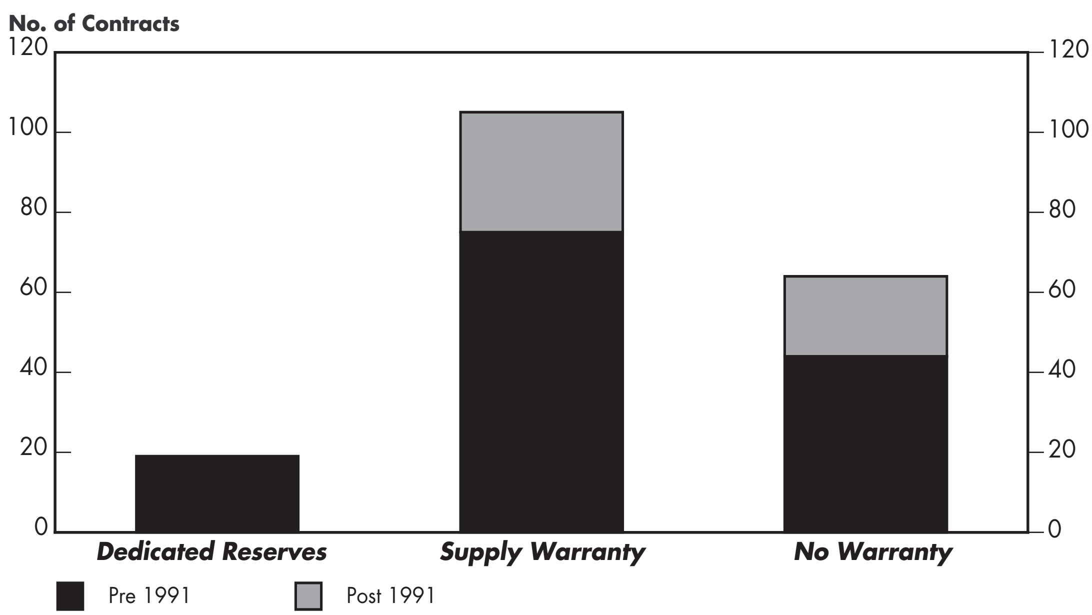
Since 1991, supply aggregators and producer/marketers have secured their obligations to deliver under deliverability contracts through corporate warranties without committing or dedicating specific reserves. Corporate warranties take several forms. They can be a relatively straightforward contractual commitment by the seller that it will maintain adequate reserves and deliverability to meet its obligation to deliver nominated volumes over the term of the agreement. Alternatively, a corporate warranty can be a specific commitment to maintain a specified level of total reserves relative to the seller's total contractual commitments (e.g. a reserve to production ratio equal to or greater than 10 years).

Supply aggregators that do not have a large asset base may offer buyers a corporate warranty that requires the seller to maintain a minimum reserve level which is backed by the reserves that have been dedicated to the aggregator's supply pool by producers. Large producer/marketers will typically offer a more general commitment to maintain adequate reserves and deliverability to meet their obligations during the term of the contract. The buyer often has the right to periodically audit the seller's reserves, deliverability and transportation contracts as well as the seller's commitments to deliver to other buyers to ensure that the seller is not over-contracted. Alternatively, the seller may be required to provide a regular report of its reserves prepared by a recognized independent reservoir engineering firm. In many cases, if the seller's reserves and/or deliverability fall below the specified level, the seller is obligated to take corrective action, including dedicating unencumbered reserves to the contract. Failure to take appropriate action usually gives the buyer the right to reduce the contract quantities.

Of the approximately 200 long-term contracts included in the survey, 20 contracts are backed by dedicated reserves, 105 contracts are backed by explicit supply warranties and 65 contracts are neither backed by dedicated reserves nor an explicit corporate warranty. This is illustrated in Figure 3-5. Of the 50 contracts negotiated since 1991, none include dedicated reserves, but 30 include an explicit supply warranty.

F I G U R E 3 . 5

Dedicated Reserves and Corporate Warranties



3.3.3 Buyer Rights to Reduce Contract Quantities

Most contracts state explicitly that the buyer can reduce the contract quantities if the seller fails to deliver nominated volumes for reasons other than force majeure. Typically, if a seller fails to deliver 90 to 100% of nominated volumes over periods as short as three months but more commonly over periods of one year, the buyer has the right to reduce the DCQ by the average daily deficiency in deliveries over the specified period. Such measures protect the buyer in a long-term contract from a situation where a seller experiences difficulties delivering the buyer's nominations on an extended basis. There have been no changes in the terms and conditions governing the buyer's rights to reduce contract quantities since 1991.

3.3.4 Seller Indemnities

The primary risk that a buyer faces in the event that a seller fails to deliver nominated volumes is the possibility of having to purchase make-up gas supplies at premium prices compared to the contract price and/or bear pipeline penalties and unabsorbed demand charges on contracted pipeline capacity.

It has almost become universal to include specific clauses in long-term gas contracts in which the seller explicitly indemnifies the buyer against costs that may arise as a result of a failure by the seller to deliver nominated volumes of gas. The most common costs that are included are: i) the incremental cost of replacement gas; ii) pipeline penalties; and iii) the cost of unabsorbed demand charges.

The use of seller indemnity clauses became widespread after deregulation and 44 of the 50 contracts negotiated since 1991 include a specific indemnity against costs that the buyer may incur as a result of delivery shortfalls. Seller indemnities were non-existent in gas contracts prior to deregulation.

3.3.5 Daily Obligations to Deliver

Under most firm contracts, the buyer may nominate up to the DCQ each day and the seller is committed to meet the nomination. However, a number of contracts executed between 1985 and 1991 by the central Canadian LDCs give them the right to nominate above the DCQ (e.g., 110 or 125 percent of the DCQ) on any given day. Buyers used this right as a source of backup gas supply in the event that one of their other suppliers encountered deliverability difficulties. The liquidity and reliability of today's spot markets as a source of backup gas supply has reduced the importance or value of this right.

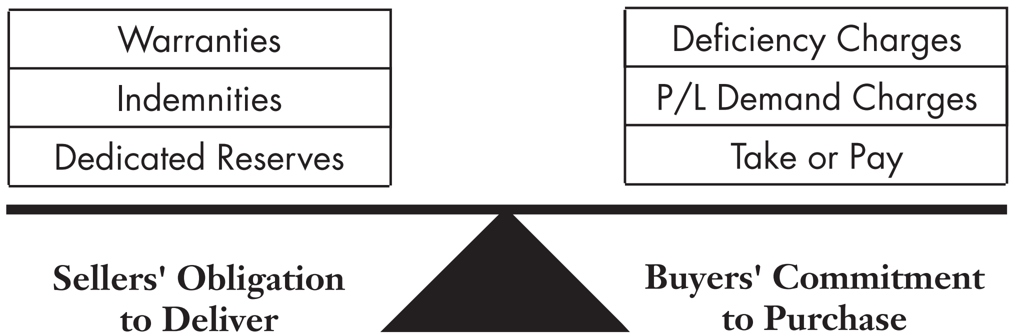
Parties to many of the contracts negotiated in the late 1980's, which included the right to over-nominate, have either reduced or eliminated this right. None of the contracts negotiated since 1991 give the buyer the right to nominate more than the DCQ.

3.4 Contract Balance

While the terms and conditions of a contract that bind or reinforce the buyer's and seller's commitments to purchase and deliver are important, also of importance is the balance between the seller's and the buyer's respective commitments. It is difficult to assess fully either the buyer's or the seller's commitments in isolation from the other parties' obligations.

F I G U R E 3 . 6

Contract Balance



As shown in Figure 3-6, there are numerous combinations of different mechanisms that are used by parties to secure the obligations to deliver and to purchase.

Between 1985 and 1991, there was a tendency by both buyers and sellers entering into new contracts to be conservative by negotiating multiple mechanisms into a contract to secure the other party's commitments (often referred to as the "belt and suspenders" approach). For instance, it was not uncommon for contracts negotiated during this period to include both significant demand charge obligations and no self-displacement provisions to secure the buyer's obligations. This conservatism stemmed from the new and unknown marketplace that was evolving and the lack of a liquid spot market to absorb unexpected fluctuations in contract load factors.

By 1993, the confidence that both buyers and sellers had in the marketplace increased immensely. Contract load factors and reliability of supply had increased sharply. These changes enabled parties to streamline long-term gas contracts.

Most contracts negotiated since 1991 secure the seller's commitment to deliver through seller indemnities possibly backed by an explicit corporate warranty. The buyer's obligations are often secured through a simple gas inventory charge or deficiency charge payable on gas not nominated. If the point of sale is downstream of Empress, the buyer is also usually required to pay pipeline demand charges associated with downstream pipeline capacity on unnominated volumes if the capacity remains unutilized. In effect, GIC and pipeline demand charges indemnify the seller against fixed costs incurred to meet its delivery obligation.

In more recent contracts, buyers have indemnified the seller against out-of-pocket costs or liquidated damages that may be incurred if full volumes are not purchased. For example, if the contract price is \$2.00/GJ but the seller was only able to realize \$1.80 on unnominated volumes, the buyer must compensate the seller \$.20/GJ for each unit not purchased plus, in some cases, a marketing fee (e.g. \$ .05/GJ). These mechanisms parallel the seller indemnities found in a large number of long-term contracts.

SUMMARY AND CONCLUSIONS

Prior to natural gas deregulation during the mid-1980's, Canadian and U.S. buyers secured virtually all their gas supply requirements through long-term contracts. These contracts formed the basis for the financing underlying exploration and development programs, and pipeline projects necessary to develop the Canadian gas industry. There were only a relatively small number of buyers that were typically either Canadian LDCs or U.S. interstate pipelines. The number of sellers prior to deregulation was also small. Most marketers of western Canadian gas were supply aggregators that were usually associated with a Canadian pipeline.

Contract Structure

Given the small number of buyers and sellers, and the fact that almost all Canadian gas was traded under long-term contracts prior to deregulation, the DCQ under most contracts was typically very large, often exceeding 5.7 $10^6m^3/d$ (200 MMcf/d). Faced with growing concerns of energy shortages during the 1960's and 1970's, buyers attempted to lock up secure gas supplies by negotiating long-term contracts with 20- and 25-year terms.

Deregulation of natural gas markets in the mid-1980's encouraged new buyers and sellers to enter the marketplace; many negotiated long-term contractual arrangements for Canadian gas. As a result, the number of long-term contracts increased sharply by the early 1990's although the typical size of a long-term contract was smaller and contract terms were shorter.

More recently, under FERC Order 636, U.S. interstate pipelines ceased to be natural gas merchants; consequently, their large volume, long-term contract arrangements for western Canadian gas supply have been terminated. Although some of this gas supply has been recontracted to several U.S. LDCs on a long-term basis, the total volume of gas contracted under long-term agreements has declined from 200 $10^6m^3/d$ (7.0 Bcf/d) in 1991 to 159 $10^6m^3/d$ (5.6 Bcf/d) in 1995. With the exit of U.S. interstate pipelines, Canadian and U.S. LDCs have become the major buyers of Canadian gas under long-term contract arrangements.

It is possible that further volumes of Canadian gas that were released by U.S. interstate pipelines may be recontracted on a long-term basis to U.S. LDCs over the next year. However, in many states, such as New York, Ohio, New Jersey and California, LDCs are unbundling their services, in a similar manner as the U.S. interstate pipelines. To the extent that U.S. end-users elect to purchase their gas requirements directly from producers and marketers rather than from LDC system supplies, it may become necessary to amend many of the long-term contracts with U.S. LDCs over the next few years. These amendments may include mechanisms similar to the ODV adjustment terms found in many of the long-term contracts with Canadian LDCs which faced significant direct purchase activity in the late 1980's and early 1990's.

Since the late 1980's, Canadian LDCs have been restructuring their long-term gas supply portfolios. In particular, the portfolios of central Canadian LDCs have steadily been shrinking in size as end-users elect to purchase their gas requirements directly from producers and marketers under short-term contracts. Given the increased confidence in the size of the western Canadian resource base and in the ability of the upstream sector to develop and produce gas, as well as the greater reliability of gas purchased under short-term arrangements and the inherent flexibility of short-term contracts, it is not expected that central Canadian LDCs will increase the volume of gas that they purchase under long-term contracts. Similarly, it is expected that as the long-term contracts supplying the Alberta LDCs expire, they will be replaced with short-term agreements. There have been few changes in terms of the size and structure of the BC Gas supply portfolio since it was restructured and diversified with several, relatively small long-term contracts in 1991.

The cogeneration market is a continuing one for long-term gas in both Canada and the U.S. This market experienced rapid growth in the late 1980's and early 1990's, has stabilized in recent years but, is expected to continue as an important market for Canadian gas under long-term contracts. The term of a typical contract with a cogeneration plant is about 15 years.

More recently, U.S. gas marketers have emerged as a new market for gas purchased under long-term contracts. To the extent that they can offer gas producers assured access to long-term markets on terms attractive to both sellers and the buyers, the volume of gas contracted to U.S. marketers is expected to grow. The term of these contracts will likely be ten years or less.

The annual volume of gas contracted under long-term agreements today is approximately 58 10^9m^3 (2,050 Bcf). This total is expected to decline sharply over the next decade to approximately 13.3 10^9m^3 (470 Bcf). By the year 2007, almost all gas sold under long-term contracts may be sold to cogenerators and U.S. marketers.

Terms and Conditions

When deregulation was first implemented in the mid-1980's, there was considerable uncertainty among both buyers and sellers with respect to how different buyers and sellers would perform under contracts, particularly new buyers and sellers that were entering the market. In the face of this uncertainty, parties negotiating long-term contracts during the late 1980's and early 1990's often contracted conservatively, securing the other party's commitments through onerous or multiple penalty clauses that could be invoked in the event of contract failure.

In the early years following deregulation, there was little information available with respect to short or long-term gas prices. The pricing terms of long-term export contracts were either complex formulas based on alternative fuels such as oil products or U.S. pipeline and LDC WACOGs. The price of gas purchased under long-term contracts by Canadian LDCs was typically renegotiated each year, a difficult and time consuming exercise.

Since the early 1990's, much greater confidence in both Canadian and U.S. short-term gas markets has developed. Markets have become very liquid both in terms of the volumes of gas that are traded and the number of independent parties participating in the market. In addition, accurate and timely market information, including pricing information, is readily available to all parties. NYMEX futures contracts have become widely accepted as indicators of the price of gas to be delivered over future periods at specific delivery points.

In response to these changes, most parties negotiating long-term contracts in recent years have indexed the price of gas to either U.S. or Canadian short-term or spot gas prices. The choice of

U.S. or Canadian spot prices usually depends on the delivery point and the buyer's alternative sources of gas supply.

Since 1993, the annually-negotiated pricing terms of most long-term contracts to supply Canadian LDCs have been amended. Today, most long-term prices are indexed to Alberta spot prices at either Empress or AECO 'C'/NIT. A smaller number of contracts were amended to include a NYMEX based index less an Empress basis differential. In B.C., much of the long-term gas is priced against the spot price of gas at Sumas or NYMEX less a Sumas basis differential.

Cogeneration contracts have a variety of pricing terms. Many contracts have prices that are fixed for the full term of the agreement or, more commonly, a fixed price with an annual escalator. Other cogeneration contracts are indexed to fuel oil, coal and spot gas prices.

As long-term contract prices became more market sensitive, they began to track the market much more closely and, as spot markets in both Canada and the U.S. became increasingly liquid, it has become less important to secure the buyer's and the seller's performance under long-term contracts through onerous penalty clauses. Today's contracts are often simpler than contracts negotiated in the late 1980's and early 1990's. The trend is towards contract terms under which the seller and buyer simply indemnify the other party against the out-of-pocket expenses or liquidated damages incurred in the event of a failure to either deliver or purchase for reasons other than force majeure.

Given the interest in risk management by sellers and buyers, there is also a trend towards greater standardization of long-term contracts to facilitate hedging activity in the financial or the over-the-counter market. It is expected that this trend will continue.

Annual Contract Quantity (ACQ)	The daily contract quantity times the number of days in the year.
City-gate	The delivery point or the point of intersection between a gas transmission pipeline and a local distribution system.
Cogeneration	The use of a fuel source in a reciprocating engine or gas turbine to generate both electrical and thermal energy to optimize fuel efficiency. The dominant demand for energy may be either electrical or thermal.
Commercial Sector	That portion of the natural gas market consisting of businesses and institutions including government, agriculture, the service sector, schools, hospitals and apartment buildings.
Commodity Charge	A charge payable by a gas purchaser in a sales contract for each unit of gas purchased. The unit charge generally covers the commodity component of any applicable pipeline tolls and the cost of gas.
Contract Demand	The amount of natural gas a seller agrees to deliver on a periodic (daily, monthly, annually) basis in accordance with a gas purchase agreement. Contract demand is a maximum amount.
Contract Term	The term of effectiveness of a contract. It may not be possible to determine accurately from the contract language what will be the actual effective term of the contract, unless specific dates are set out. Many contracts state (1) that the term begins from the date of initial production or delivery, (2) that the contract may be extended from month to month or year to year until notice of termination is given, or (3) that the contract will remain in effect for the life of the lease or until the dedicated reserves are depleted.
Contracted Reserves	Natural gas reserves dedicated to fulfil natural gas purchase agreements.
Core Market	Generally that part of the gas market that does not possess fuel switching capability in the near term; typically residential, commercial and small industrial users.

Deficiency Charge — A charge per unit of deficiency imposed when a buyer's actual purchases fall below a required minimum or threshold level, as under reservation fees and gas inventory charges.

Deliverability — The amount of natural gas a well, field, pipeline, or distribution system can supply in a given period of time. Also, the practical output from a storage reservoir.

Delivery Point — The point on a pipeline's system at which it delivers natural gas that it has transported.

Demand Charge — A fixed, usually monthly obligation of a gas purchaser in a sales contract. It may cover some or all of a seller's fixed costs and is payable regardless of volumes actually transported.

Direct Sale or Direct Purchase — Gas purchase arrangements transacted directly between producers, brokers or marketers and end-users.

Displacement Volume — A direct purchase volume is a displacement volume when, assuming the absence of such direct purchase, the LDC could supply the account on a firm contract basis without itself contracting for additional firm volumes to accommodate the demand.

Distribution System — Generally, mains, service connections, and equipment that carry or control the supply of natural gas from interprovincial or interstate pipeline systems, or the point of local supply to individual end-users.

End-Use — One who actually consumes or burns natural gas, as opposed to one who sells or resells it.

Federal Energy Regulatory Commission (FERC) — An agency within the United States Department of Energy that, among other things, has jurisdiction over natural gas companies and producers that sell or transport gas in interstate commerce forresale. With respect to the natural gas industry, the general regulatory principles of the FERC are defined in the Natural Gas Act (NGA), the Natural Gas Policy Act (NGPA) and the natural Gas Wellhead Decontrol Act. The FERC also has jurisdiction over wholesale interstate electric rates, hydroelectric licensing, and oil pipeline rates. The predecessor to the FERC was the Federal Power Commission (FPC).

Firm Customer — A customer for whom contract demand is reserved and to whom the supplier is obligated to provide service.

Firm Service — Gas transportation service which provides a shipper with a guarantee that the contracted transportation capacity will be available and that service will not be interrupted, except in exceptional cases. Firm transportation provides shippers with the highest priority service.

Force Majeure Clause A provision common in contracts that defines force majeure for purposes of the contract and specifies what effect force majeure will have on the rights and obligations of the parties under the contract. Typically, a force majeure clause provides that non-performance of an obligation of a party will be excused to the extent and for so long as performance is prevented by an event of force majeure. Force majeure provisions usually exclude obligations to pay money; require the party affected to give timely notice to the other party and to use reasonable diligence to remedy the situation; and may reserve for either the party not affected by the force majeure, or both parties, the right to terminate or suspend the contract if the force majeure prevents performance for some specified period of time.

Gas Inventory Charge (GIC) A charge paid by a buyer to its supplier for holding natural gas supplies ready to be delivered to the buyer. These charges may take at least two forms: (1) an "option" or "reservation" charge, in which a set fee is paid at the outset for each unit of delivery entitlement, and (2) a "deficiency" charge, in which the buyer pays after the fact a set fee for each unit of natural gas not taken up to a pre-determined minimum or threshold quantity.

Industrial Sector The portion of the natural gas market consisting of manufacturing, forestry and mining operations.

Interruptible Customer A customer that receives service only at those times and to the extent that firm customers do not demand all of the available service.

Interruptible Service Gas transportation service that may be curtailed or interrupted by the pipeline on short-notice. Interruptible service is typically offered when a pipeline has excess capacity on the system.

Interprovincial or of Interstate Pipeline A natural gas pipeline company that is engaged in the transportation natural gas across provincial, state or international boundaries, and is subject to NEB or FERC jurisdiction.

Load Factor The ratio of the average load over a designated period of time to the contracted maximum load, expressed in percent.

Local Distribution Company (LDC) A company that obtains the major portion of its natural gas revenues from the operations of a retail gas distribution system and that operates no transmission system other than incidental connections within its own system or to the system of another company.

Market-Out A provision in a natural gas sales agreement that allows one or both parties to demand renegotiation of the sales price and/or volumes of the contract. There are many forms of market out provisions with differing rights and effects.

Netback Price	The per-unit price received by a gas producer from the sale of gas in end-use markets, less applicable costs. These typically include transportation and marketing fees.
Nomination	A buyer's request for service under a service agreement.
Open Access	A basis for the provision of transportation services by inter-provincial, interstate and intra-provincial pipelines. The pipeline must provide service on a non-discriminatory basis to anyone requesting service at regulated rates.
Operating Demand Volumes	Volumes specified in a firm service contract less the volumes deemed to have been displaced by direct sales.
Premium	In the context of sales of natural gas, a price differential reflecting differences in the quality of the product or relationships, particularly for long-term firm commitments as opposed to spot sales.
Supply Aggregator	A supply aggregator purchases gas from several producers for the purpose of resale to a range of consumer interests.
Reservation Fee	A set unit charge payable by the recipient of a service based on total entitlement. Similar to a "demand" charge.
Reserves to Production Ratio	Remaining reserves divided by annual production.
Residential Sector	The portion of the natural gas market consisting of private dwellings and larger residential units with individually-metered apartments.
Sale for Resale	A sale of natural gas to a customer who will in turn resell the gas to someone else. A sale of natural gas other than to an end-user, e.g., a sale by a producer/marketer to a U.S. interstate pipeline that will in turn resell the natural gas to a local distribution company, or to a local distribution company that will in turn resell the natural gas to an end-user.
Self-Displacement	The purchase of gas by a buyer to displace gas it would otherwise obtain under its long-term contracts.
Shipper	An individual or company that contracts with a pipeline for transportation of natural gas. Normally, a shipper retains title to all natural gas delivered to the pipeline while it is being transported by the pipeline.
Spot Market	Commodity transactions in which the transaction commencement is near term (e.g., within 10 days) and the contract duration is relatively short (e.g., 30 days).
Spot Sale	Transactions of gas which are generally for 30 days or less.

Take-or-Pay Clause	A contract provision whereby a purchaser agrees to pay for a specified volume of natural gas during a period whether or not the contract deliveries are taken.
Transportation Contract	A contract setting forth the terms and conditions applicable to transportation service.
Unbundled Service	The separation of pipeline services into discrete components (e.g., transportation, storage, gathering, sales, etc.). With unbundling, separate fees are charged for each service, based upon only the cost of providing that service.
Warranty Contract	A natural gas sales contract in which the seller commits to deliver a stated quantity of natural gas over a stated period of time, without limitation to or commitment of specific reserves or sources of natural gas, and generally with no production-related reservations.
Weighted Average Cost of Gas (WACOG)	The weighted average unit cost of a supply of natural gas. WACOG is calculated as the total cost of all natural gas purchased during a period divided by the total quantity purchased during the same period. This rate often serves as the basis upon which LDC system tariff rates are computed.
Wellhead Price	Used to specify a price reference or delivery point for natural gas. It is generally considered to be the price the producer receives after processing and gathering costs have been subtracted.

U . S . N O R T H E A S T

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			(10^6m^3/d)	(MMcf/d)
TransCanada	Boundary Gas	LDC	2.62	92.5
TransCanada	ANE	LDC	7.79	275
TransCanada	Ocean State Power	Cogen	0.708	25
TransCanada	Penn South	LDC	0.057	2
TransCanada	Penn Gas - Water	LDC	0.431	15.2
TransCanada	Holvoke Gas	LDC	0.051	1.8
TransCanada	Norstar	LDC	0.071	2.5
TransCanada	Vermont gas	LDC	0.595	21
TransCanada	St. Lawrence Gas	LDC	0.907	32
TransCanada	Elizabethtown Gas	LDC	0.283	10
TransCanada	Niagara Mohawk	LDC	1.445	51
TransCanada	Megan-Racine	Cogen	0.331	11.7
TransCanada	LG & E	Cogen	0.51	18
ProGas	ANE	LDC	1.87	66
ProGas	Ocean State Power	Cogen	1.416	50
ProGas	Ocean State Power	Cogen	0.708	25
ProGas	Lockport	Cogen	0.34	12
ProGas	Northeast Energy	Cogen	1.416	50
ProGas	North Jersey	Cogen	0.635	22.4
ProGas	MassPower	Cogen	0.708	25
ProGas	NYSEG	LDC	0.255	9
Shell	Saranac Power	Cogen	1.445	51
Shell	CETI	Cogen	0.397	14
Shell	Granite State	LDC	0.708	25
Shell	Granite State	LDC	0.992	35

U.S. NORTHEAST

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			(10^6m^3/d)	(MMcf/d)
CanStates	BG &E	LDC	0.708	25
CanStates	LILCO	LDC	0.425	15
CanStates	PG & E	LDC	0.992	35
CanStates	Hopewell Cogen	Cogen	1.371	48.4
Various	Indeck-Yerkes	Cogen	0.482	17
Various	Indeck-Oswego	Cogen	0.198	7
Ramaro	KCS	Cogen	0.17	6
Westcoast	Rochester Gas	LDC	0.453	16
Amoco	Con Edison	LDC	0.85	30
Star Oil	Fulton Cogen	Cogen	0.17	6
Esso	Boston Gas	LDC	0.992	35
Atcor	ANE	LDC	1.057	37.3
AEC	ANE	LDC	0.533	18.8
Renaissance	Kamine-C	Cogen	0.402	14.2
Renaissance	Kamine-SG	Cogen	0.402	14.2
Opinac	Pawtucket	Cogen	0.181	6.4
Paramount	JMC Selkirk	Cogen	0.652	23
Various	Dartmouth	Cogen	0.652	23
Cdn Hunter	G.A.S.	Cogen	0.85	30
Wascana	O & R Utilities	LDC	0.708	25
Renaissance	NEP	Cogen	0.425	15
Sceptre	NEP	Cogen	0.567	20
Husky	Power City	Cogen	0.567	20
Renaissance	Iroquois Energy	Marketer	0.283	10
Rio Alto	Coastal	Marketer	0.142	5

U . S . N O R T H E A S T

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			(10^6m^3/d)	(MMcf/d)
Group of 7	Coastal	Marketer	1.161	41
Morgan	Coastal	Marketer	0.283	10
Enron	Enron US	Marketer	0.425	15
Atcor	Makowski Selkirk	Cogen	0.482	17
Esso	Makowski Selkirk	Cogen	0.538	19
Pan Canadian	Makowski Selkirk	Cogen	0.538	19
Home	AG-Energy	Cogen	0.467	16.5
North Canadian	Kamine-I	Cogen	0.453	16
North Canadian	Kamine	Cogen	0.283	10
Sceptre	Encogen	Cogen	0.419	14.8
Pan Canadian	Brooklyn Navy	Cogen	0.425	15
Crestar	Brooklyn Navy	Cogen	0.283	10
Renaissance	Northern Utilities	LDC	0.028	1
Renaissance	Bay State	LDC	0.181	6.4
Total U.S. Northeast			**46.887**	**1655.1**

U.S. PACIFIC NORTHWEST

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			(10^6m^3/d)	(MMcf/d)
Mobil	Cascade	LDC	0.329	11.6
Mobil	Washington Natural	LDC	0.272	9.6
Summit	NW Natural	LDC	0.227	8
CanWest	NW Natural	LDC	2.606	92
Poco	NW Natural	LDC	0.445	15.7
Poco	IGI	LDC	0.567	20
Poco	Washington Natural	LDC	0.425	15
Amoco	Washington Natural	LDC	0.708	25
Westcoast	Washington Natural	LDC	0.283	10
Westcoast	Cascade	LDC	0.136	4.8
CanWest	Encogen NW	Cogen	0.263	9.3
CanWest	TM Star	Cogen	0.283	10
CanWest	Klickitat	Cogen	0.263	9.3
Talisman	Tenaska 1	Cogen	0.51	18
Talisman	Rupert Cogen	Cogen	0.079	2.8
Talisman	Glenn Ferry Cogen	Cogen	0.071	2.5
Husky	Tenaska 1	Cogen	0.368	13
Husky	Tenaska 2	Cogen	0.405	14.3
Petro Canada	Tenaska 1	Cogen	0.425	15
Shell	Tenaska 2	Cogen	0.606	21.4
ECO Gas	Sumas Cogen	Cogen	0.601	21.2
CanStates	Hermiston	Cogen	0.841	29.7
Home	Hermiston	Cogen	0.425	15
Chevron	Hermiston	Cogen	0.561	19.8
Westcoast	NW Natural	LDC	0.66	23.3
Westcoast	Cascade	LDC	0.283	10
Westcoast	Cascade	LDC	0.941	33.2
Westcoast	Washington Natural	LDC	2.714	95.8
AEC	Washington Water	LDC	0.725	25.6
Westcoast	Washington Water	LDC	0.541	19.1
Amerada Hess	Washington Water	LDC	0.476	16.8
Pan Canadian	Washington Water	LDC	0.538	19
Total U.S. Pacific Northwest			**18.578**	**655.8**

CALIFORNIA

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			($10^6m^3/d$)	(MMcf/d)
Pan Alberta	Socal	LDC	6.799	240
Canadian Hunter	San Diego Gas	Cogen	0.567	20
Husky	San Diego Gas	Cogen	0.567	20
AEC	Socal	Cogen	1.482	52.3
Esso	Socal	Cogen	1.482	52.3
Shell	Socal	Cogen	1.482	52.3
TransCanada	Socal	Cogen	1.482	52.3
Westcoast	Burbank	LDC	0.136	4.8
Westcoast	Glendale	LDC	0.116	4.1
Westcoast	Pasadena	LDC	0.116	4.1
Total California			**14.227**	**502.2**

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			($10^6m^3/d$)	(MMcf/d)
TransCanada	SE Migas	LDC	0.425	15
TransCanada	Mich Con	LDC	0.312	11
TransCanada	Minnegasco	LDC	1.445	51
TransCanada	NMU 1	LDC	0.283	10
TransCanada	NMU 2	LDC	0.751	26.5
TransCanada	Midland Cogen	Cogen	0.425	15
TransCanada	Wisc PS	LDC	0.776	27.4
TransCanada	Wisc P & L	LDC	0.238	8.4
TransCanada	Wisc gas Co	LDC	2.533	89.4
TransCanada	Wisc F & L	LDC	0.21	7.4
TransCanada	Wisc Natural Gas	LDC	0.751	26.5
TransCanada	Mich Gas U	LDC	0.204	7.2
ProGas	Consumers Power	LDC	2.408	85
ProGas	NSP	LDC	0.212	7.5
ProGas	Wisc Gas	LDC	0.187	6.6
ProGas	Wisc PS	LDC	0.224	7.9
ProGas	Mich Gas U	LDC	0.076	2.7
ProGas	Wisc F & L	LDC	0.085	3
ProGas	Wisc Gas	LDC	0.807	28.5
ProGas	Wisc natural Gas	LDC	0.303	10.7
ProGas	Wisc P & L	LDC	0.096	3.4
ProGas	Wisc PS	LDC	0.314	11.1
Pan Alberta	PAGUS	LDC	8.499	300
Morrison	Coastal	Marketer	0.198	7
Petro Canada	Coastal	Marketer	0.314	11.1

U.S. MIDWEST

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			($10^6 m^3/d$)	(MMcf/d)
ProGas	Natural Gas Clearinghouse	Marketer	0.85	30
ProGas	Tenaska	Marketer	0.567	20
Crestar	NSP	LDC	0.184	6.5
Crestar	NSP	LDC	0.425	15
Norcen	Midland Cogen	Cogen	0.283	10
Husky	Midland Cogen	Cogen	0.425	15
Shell	Midland Cogen	Cogen	0.425	15
Poco	Midland Cogen	Cogen	0.425	15
North Canadian	Midland Cogen	Cogen	0.283	10
Cdn Montana Pipe	Montana Power	LDC	1.133	40
Cdn Oxy	NSP	LDC	0.212	7.5
Shell	Midwest Gas	LDC	0.567	20
Shell	Enron	Marketer	0.102	3.6
Amoco	NSP	LDC	0.425	15
Renaissance	Amgas	LDC	0.142	5
Total Midwest			**28.524**	**1006.9**

CENTRAL CANADA

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			(10^6m^3/d)	(MMcf/d)
TransCanada	Consumers	LDC	6.686	236
TransCanada	Centra Ont	LDC	0.969	34.2
TransCanada	Centra Man	LDC	2.323	82
TransCanada	Union	LDC	1.241	43.8
TransCanada	Gaz Métro	LDC	2.493	88
Pan Alberta	Gaz Métro	LDC	0.618	21.8
Pan Alberta	Gaz Métro	LDC	0.388	13.7
Shell	Union	LDC	0.238	8.4
Shell	Union	LDC	0.207	7.3
Wascana	Union	LDC	0.326	11.5
Amerada Hess	Union	LDC	0.13	4.6
Canadian Hunter	Union	LDC	0.232	8.2
Enron	Union	LDC	0.238	8.4
Gulf	Union	LDC	0.295	10.4
Gulf	Union	LDC	0.286	10.1
TransCanada	Union	LDC	0.346	12.2
Northstar	Union	LDC	0.113	4
Westcoast	Union	LDC	0.127	4.5
Westcoast	Union	LDC	0.122	4.3
Westcoast	Union	LDC	0.071	2.5
Norcen	Centra Ont	LDC	0.17	6
A	Consumers	LDC	0.099	3.5
B	Consumers	LDC	0.3	10.6
C	Consumers	LDC	0.399	14.1
D	Consumers	LDC	0	0
E	Consumers	LDC	0.399	14.1
F	Consumers	LDC	0.198	7
G	Consumers	LDC	0.399	14.1
H	Consumers	LDC	0.3	10.6
J	Consumers	LDC	0.201	7.1
K	Consumers	LDC	0.099	3.5
L	Consumers	LDC	0.201	7.1
Novergaz	Gaz Métro	LDC	0.212	7.5
Central Canada			**20.428**	**721.1**

BRITISH COLUMBIA

Survey of Long-term Natural Gas Contracts (To December 31, 1995)

Seller	Buyer	Buyer Type	DCQ	
			($10^6m^3/d$)	(MMcf/d)
Amoco	BC Gas	LDC	0.795	28.1
Anderson	BC Gas	LDC	0.375	13.2
Canadian Hunter	BC Gas	LDC	0.2	7.1
Canadian Hunter	BC Gas	LDC	0.57	20.1
Canadian Hunter	BC Gas	LDC	0.33	11.6
CanWest	BC Gas	LDC	3.965	140
Esso	BC Gas	LDC	0.14	4.9
Mobil	BC Gas	LDC	0.283	10
NorPac	BC Gas	LDC	0.71	25.1
NorPac	BC Gas	LDC	1.983	70
PennWest	BC Gas	LDC	0.142	5
Petro Canada	BC Gas	LDC	0.142	5
Petro Canada	BC Gas	LDC	0.425	15
Petro Canada	BC Gas	LDC	0.708	25
Ranger	BC Gas	LDC	0.283	10
Ranger	BC Gas	LDC	0.565	19.9
Rigel	BC Gas	LDC	0.1	3.5
Shell	BC Gas	LDC	0.283	10
Summit	BC Gas	LDC	0.28	9.9
Talisman	BC Gas	LDC	1.243	43.9
Unocal	BC Gas	LDC	0.3	10.6
Total British Columbia			**13.822**	**487.9**