A North American Gas Trade Model (GTM)

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Natural gas ranks second only to crude oil as a primary source of energy in North America. During recent years, gas has satisfied 25 percent of all energy requirements in the United States. Most of this gas has been produced domestically, but 5 to 10 percent has been supplied by pipeline imports from Canada and Mexico. Additional amounts could be provided by pipelines from Alaska or by LNG (liquefied natural gas) imports from overseas, but these facilities would be expensive, and their construction continues to be delayed. Transport costs are high, and geography plays a far more important role in international gas markets than in the oil markets. For this reason, we view the North American continent as a largely self-contained system.

Canadian gas production is centered in Alberta. The United States is a major market for these producers, and about a third of all gas produced in Canada has been exported to the United States. For Mexican producers, exports to the United States represent less than 5 percent of total production. If present policies were to change, however, there could be a considerable increase in Mexico's export levels.

Since the 1973–1974 Arab oil embargo, many individual energy supply and demand studies have been done for Canada, Mexico, and the United States, but there have been few attempts to arrive at consistent projections of gas trade between the three countries. Analysts typically study their own nations closely, but adopt arbitrary assumptions about the volume of international gas trade, a process than can easily lead to logical inconsistencies. In a poll

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of projections to the year 2000 (Manne and Schrattenholzer, 1984) it was found that the median of U.S. import estimates was twice as high as that of Canadian export estimates!

It is not easy to analyze the determinants of international trade in natural gas. Difficulties include: (1) limited access to information on the supply and demand situation in other countries and (2) continual changes in the complex regulations that have governed both domestic prices and international gas trade. This process has led to a series of high-level negotiations on prices and quantities between the three governments—each responsive to domestic political constituencies.

Domestic wellhead prices are moving slowly toward deregulation within the United States. By 1990, unless there are legislative changes, U.S. gas supplies and demands will be governed primarily by market forces. These institutional changes provide the background for the modeling work reported here. We shall examine the outlook through a Gas Trade Model (GTM). Compared with other gas sector models, GTM is exceedingly simple. It is intended primarily to provide insights into North American gas trade issues.

GTM is a market equilibrium model that allows interdependence between gas prices and the quantities traded at a single point in time. Regionally disaggregated trade flows are projected between Canada, Mexico, and the United States. The model is intended to provide a background for realistic bargaining over international prices and risk sharing in an era when the U.S. market becomes deregulated, but Canada and Mexico maintain export controls and lower domestic prices than those in the United States. If present policies are continued, Mexico will export only minor amounts of gas.

GTM computes for both 1990 and 2000 market-clearing prices and a possible pattern of trade flows between 11 supply regions (1 in Mexico, 3 in Canada, and 7 in the United States) and 14 demand regions (1 in Mexico, 3 in Canada, and 10 in the United States). The supply and demand regions (shown as row and column labels, respectively, in Table 1) were selected to reflect the major options in potential sources and destinations for gas traded internationally in North America. Table 1 contains our estimates of the flows and prices that prevailed in 1982, which provides a statistical basis for projections to subsequent years.

The Canadian regions are defined for consistency with the BALANCE model of Daniel and Goldberg (1981). The U.S. gas supply and demand regions are those employed in GAMS and other modeling systems used at the Energy Information Administration (EIA). See, for example, EIA (1984). This permitted us to take advantage of the most recent data and analysis developed at the EIA and elsewhere within the Department of Energy with respect to supplies, demands, and transport cost estimates (EIA, 1983). Key inputs to GTM include: (a) the regional distribution of gas supplies and

Table 1. 1982 Flows (TCF) and Unit Transportation Costs ($/MCF)

From supply \ *To demand*	1 *Mexico*	2 *Westcan.*	3 *Ont./Que.*	4 *Atlantic*	5 *New Eng.*	6 *NY/NJ*	7 *Mid-Atl.*	8 *S. Atlantic*	9 *Midwest*	10 *SWest*	11 *Central*	12 *N. Cntrl*	13 *West*	14 *NWest*	*Supplies* *Prices*
1. MEXICO	1.00					0.02	0.02	0.02	0.02				0.01		1.09
	0.25					2.29	2.22	2.04	1.93				1.95		0.25
2. ALTA/BC		0.85	0.75		0.01	0.03	0.01		0.26			0.04	0.30	0.14	2.39
		0.40	0.90		1.15	1.10	1.10		0.80			0.65	0.70	0.65	1.60
3. ATLANTIC				0.00	0.00										0.00
				0.00	1.50										••••
4. ARCTIC		0.00													0.00
		0.00													••••
5. APPALAC						0.05	0.23		0.29						0.57
						0.93	0.86		0.57						2.90
6. US GULF					0.30	1.11	0.93	1.67	2.21	3.11					9.33
					1.91	1.35	1.28	1.10	0.99	0.31					2.48
7. MID-CON									0.45	1.92	0.93				3.30
									1.07	0.39	1.19				2.40
8. P. BASIN									0.06	1.20			1.27		2.53
									1.24	0.56			1.26		2.23
9. ROCKIES									0.48		0.05	0.56	0.04	0.07	1.20
									0.61		0.73	0.70	0.63	1.91	2.86
10. PACIFIC													0.40		0.40
													0.35		3.00
11. ALASKA															0.00
															••••
Demands	1.00	0.85	0.75	0.00	0.31	0.21	1.19	1.69	3.77	6.23	0.98	0.60	2.02	0.21	20.81
Prices	0.50	2.00	2.50	••••	4.87	3.83	3.76	3.57	3.51	2.79	3.29	3.56	3.68	4.89	

Note: Due to independent rounding, individual flows do not necessarily add to totals.

demands at alternative price levels, (b) transport changes, (c) pipeline cavity constraints, and (d) export quantity limits imposed by Canada and Mexico.

Policy modeling requires trial and error. In selecting parameters, one cannot avoid subjective judgments. Fortunately, during the course of this work, we had informal access to analysts and policymakers in all three countries. Of course, this does not ensure correctness of the results, but it did enable us to avoid some glaring errors. We are solely responsible for the results reported here and are keenly aware that continual revisions are necessary in projections of this type. Much of the background for our estimates can be found in the reports on two gas trade workshops held at Stanford University (see Goldberg, 1984, and Beltramo and Manne, 1984).

This paper will describe the formulation of GTM and a submodel of U.S. gas demands. We will report on projections for 1990 and 2000 and examine alternative Canadian export policies. We also examine selected sensitivity analyses with respect to key parameters that affect gas demands.

MODEL FORMULATION

GTM is a model of gas markets that are interrelated at a single point in time. It is a partial equilibrium model, assuming both GNP growth and the international price of oil to be exogenously determined. In some regions, prices may be free to move so as to equilibrate supplies and demands. In others, there may be disequilibria associated with controls over prices and/or quantities traded. The overall system may be described as if it were operating to maximize the sums of producers' and consumers' surpluses. This maximand also may be described as the sum of consumers' benefits less the costs of production and transportation subject to constraints on the prices and quantities traded. Solutions are obtained through MINOS (Modulus, In-Core Optimization System), a nonlinear programming code (see Murtagh and Saunders, 1983).

Except for the supply and demand variables that enter nonlinearly into the objective function, GTM is a straightforward transportation model. The primal variables are nonnegative and are defined as follows:

x_{ij} = quantity transported from supply region i to demand region j,

y_i = total quantity supplied by region i, and

z_{jk} = total quantity demanded by region j, sector k. (1)

Economic policy or technical constraints may affect one or more of these variables. For example, there may be pipeline capacity limits that impose upper bounds on the transportation variables x_{ij}. There may be lower bounds associated with take-or-pay contracts. There may be reproducibility constraints on the production variables y_i. Some of the demands may be determined by controlled prices and/or fuel-use allocation rules. Some of the supplies may be determined by export controls. Each of these conditions is described as an upper or a lower bound on an individual variable. In addition, there are the following supply and demand constraints for all regions i and j, and for all demand sectors k:

$$
\begin{aligned}
&(1.i) \qquad \sum_j x_{ij} < y_i \qquad \text{(supply constraint, region } i\text{)}\\
&(2.jk) \qquad \sum_i x_{ij} > \sum_k z_{jk} \quad \text{(demand constraint, region } j\text{)}
\end{aligned}
\tag{2}
$$

The objective function contains linear cost coefficients c_{ij} related to the transportation variables x_{ij}. The other variables enter in a nonlinear but separable form. For simplicity, we suppose that each region's supplies or sectoral demands are affected only by the price prevailing in that region. This leads to separable nonlinear terms related to the supply and demand variables, y_i and z_{jk}, respectively.

For supply region i, producers' costs are described as the integral of the supply (marginal cost) function $f_i(x_i)$. For the demands in region j, sector k, consumers' benefits are described as the area below the inverse demand (willingness-to-pay) function $g_{jk}(z_{jk})$. Thus, the overall maximand may be written as the sum of consumers' benefits minus production and transportation costs:

$$
\begin{array}{lll}
\text{consumers'} & -\ \text{producers'} & -\ \text{transportation}\\
\text{benefits} & \quad\text{costs} & \quad\text{costs}
\end{array}
$$

$$
\sum_{j,k} \int_{u=\mathbf{u}}^{z_k^j} g_{jk}(u)\,\mathrm{d}t - \sum_i \int_{u=0}^{y_i} f_i(u)\,\mathrm{d}t - \sum_{i,j} c_{ij} x_{ij}, \tag{3}
$$

where u denotes the variable of integration in each case, and $\mathbf{u}$ a lower bound on gas consumption in region j by sector k.

A market equilibrium is computed by determining values of the primal variables so as to maximize (3) subject to constraints $(1.i)$ and $(2.jk)$, and also subject to upper and lower bounds on individual variables. If the supply variable y_i is unconstrained, the equilibrium dual variable corresponding to constraint $(1.i)$ will be identical to $f_i(y_i)$, the marginal cost of production in region i. Similarly, if the sectoral demand variable z_{jk} is unconstrained, the equilibrium shadow price on constraint $(2.jk)$ will be identical to the marginal willingness-to-pay, $g_{jk}(z_{jk})$. Constraints on these primal variables lead to wedges that may be interpreted in terms of taxes or subsidies on individual supplies or demands.

The consumers' benefit functions that appear in (3) are determined assuming there is constant elasticity of demand with respect to market price. Omitting the subscripts for regional and sectoral demands, these willingness-to-pay functions are of the following form:

$$g(z) = az^b, \tag{4}$$

where the negative exponent b is the reciprocal of the price elasticity of demand. The constant a may then be determined from a single point (the reference price and quantity values) along each region's demand function.

A slightly different form is employed for the supply (marginal cost) functions. Again omitting the regional subscripts, the functions $f(y)$ are defined by a three-parameter form: $a + b/(c - y)$. In this way the elasticity of supply may be high at low production levels but approach zero as production approaches the producibility limit c. Figure 1 shows how this functional form describes our assumptions with respect to the Lower 48 supplies in the year 2000.

The curve is benchmarked at the production level (15.1 TCF) and wellhead supply price (\$7.0/MCF) projected as the reference case in NEPP83 (the National Energy Policy Plan, October 1983) (see Office of Policy, Planning and Analysis, 1983). In describing the regional distribution of these supplies, assume they are proportional to the sum of measured and inferred reserves, as estimated by the U.S. Geological Survey (see American Petroleum Institute, 1983).

If we set the marginal cost function parameter $b = 0$, we obtain an important special case—a reverse L-shaped supply curve in which marginal costs remain constant up to whatever upper bound is imposed upon y, the production level. This assumption is used for all regions and time periods in Canada and Mexico and for most of the United States in 1990. It is assumed that in 1990 production will be at its upper bound in all regions except the Gulf Coast. The Gulf Coast is the largest single producing region in North America, and it is not likely to run into serious resource depletion constraints until after 1990. In a deregulated market, therefore, its marginal supply costs will have a major impact upon the price level throughout the United States. A fuller description of GTM's formulation can be found in Beltramo, Manne, and Weyant (1984), and Manne, Beltramo, and So (1984).

GAS DEMAND SUBMODEL FOR THE UNITED STATES

Because Canada and Mexico are likely to maintain domestic price controls, their gas demands are exogenous. With deregulation, however, U.S.

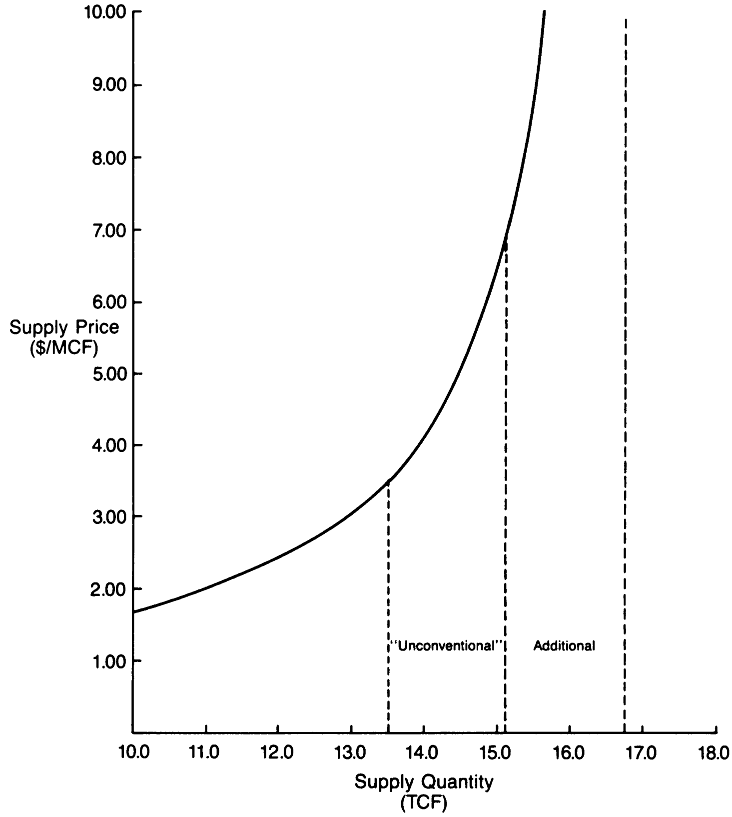


Figure 1. Lower-48 gas supplies, 2000.

demands will depend upon market prices. Taken literally, GTM computes a static market equilibrium in which current gas prices are the only variables that affect demands. Through a submodel each solution may be interpreted as a lagged adjustment not only to gas prices but also to changes in economic activity and the prices of alternative fuels.

The willingness-to-pay functions (4) are to be viewed as log-linear approximations to a more complex model of consumer behavior. The validity of these approximations depends on the choice of the parameters a and b—or equivalently, the choice of reference prices, quantities, and price elasticities. Except for the market price of gas, all other information is embodied in the choice of these parameters. Considerable care must be taken in benchmarking the inverse demand functions.

The U.S. demand submodel allows selection of reference values in a consistent fashion as well as sensitivity analysis of the underlying assumptions.

There is a gas demand function for each of four sectors: residential, commercial, industrial, and electric utilities. Let the index $i \in I = \{g, f, c, e\}$ denote, respectively, gas, fuel oil, coal, and electricity. Omitting sectoral and regional subscripts for clarity, each equation is of the following form:

$$z_t = A_t \left(\alpha \prod_{i \in I} p_{it}^{\eta_i} \right)^{\lambda} (z_{t-1}/A_{t-1})^{1-\lambda}, \tag{5}$$

where z_t = quantity of gas demanded, period t;
A_t = level of energy using-activity, period t;
α = demand constant;
η_i = long-run elasticity of gas demand with respect to the price of fuel i;
p_{it} = price of fuel i, period t; and
λ = fraction of total adjustment occurring in period t.

If all energy prices remain constant, equation (5) indicates that total gas demands will grow in proportion to energy-using activities. These activities are proportional to: (a) the number of households in the residential sector, (b) the amount of floor space in the commercial sector, (c) industrial production in the industrial sector, and (d) electricity generation in the electric utility sector. The demand per unit of energy-using activity responds to relative prices according to a Koyck-type partial adjustment model. The parameter λ represents the fraction of the total long-run price response that occurs in the current period. The short-run elasticity of demand with respect to the price of fuel i therefore is equal to $\lambda\eta_i$.

Log-linear demand equations of this type are common in the econometric literature on gas demand, although linear specifications are also quite popular. Although a linear rather than log-linear formulation of the demand equations employed here would lead to some differences in numerical results, it would not alter any conclusions drawn.

Table 2 indicates our reference case assumptions about the growth of total energy-using activity, future fuel prices, price elasticities, and rates of adjustment—by region and demand sector within the United States. The national energy-using activities and fuel price values are derived from the reference case in NEPP83. Regional demand projections are based upon the assumption that regional energy-using activities will be proportional to population. (See Wetrogan, 1983, for state population projections.) Fuel prices grow at the same rate in all regions. Although representative of views that prevailed in 1983, on future energy prices, some may see these price assumptions as high. Fortunately, one of the sensitivities we explored considers the possibility of much lower oil prices than those assumed in the reference case.

Table 2. U.S. Demand Submodel Reference Case Benchmark Assumptions

	Long-Run Price Elasticities				
Sector	*Gas*	*Fuel Oil*	*Coal*	*Electricity*	*Annual Rate of Adjustment*
Residential[a]	−0.50	0.25	0.00	0.00	0.10
Commercial	−1.00	0.40	0.00	0.00	0.15
Industrial	−1.50	1.00	0.20	0.35	0.20
Electric Utility	−2.00	1.50	0.20	0.00	0.20

	Fuel Price Growth Rates (percent/year)							
	Gas Price		*Fuel Oil Price*		*Coal Price*		*Electricity Price*	
Sector	*1982–1990*	*1900–2000*	*1982–1990*	*1990–2000*	*1982–1990*	*1900–2000*	*1982–1990*	*1990–2000*
Residential	1.81	4.09	−0.88	5.11	–	–	0.62	1.31
Commercial	2.08	4.26	−1.00	5.24	–	–	–	–
Industrial	3.95	4.82	1.29	5.64	3.42	1.18	1.33	1.67
Electric Utility	3.95	4.82	1.29	5.64	3.42	1.18	–	–

	Energy-Using Activity Growth Rates (percent/year)							
	Number of Households		*Commercial Floor Space*		*Industrial Production*		*Electrical Consumption*	
U.S. Demand Region	*1982–1990*	*1900–2000*	*1982–1990*	*1990–2000*	*1982–1990*	*1900–2000*	*1982–1990*	*1990–2000*
5. New England	1.25	0.72	2.25	1.57	3.72	2.29	3.04	1.42
6. N.Y./N.J.	0.54	0.02	1.54	0.86	3.00	1.57	2.32	0.71
7. Mid-Atlantic	1.23	0.65	2.24	1.51	3.71	2.22	3.02	1.35
8. South Atlantic	2.57	2.02	3.59	2.89	5.08	3.61	4.39	2.73
9. Midwest	1.15	0.56	2.15	1.41	3.62	2.12	2.94	1.26
10. Southwest	2.73	2.12	3.75	2.99	5.24	3.71	4.55	2.83
11. Central	1.27	0.72	2.28	1.58	3.75	2.29	3.06	1.42
12. North Central	3.30	2.78	4.33	3.66	5.83	4.38	5.13	3.50
13. West	2.85	2.21	3.87	3.08	5.36	3.80	4.67	2.92
14. Northwest	3.12	2.46	4.14	3.33	5.64	4.06	4.94	3.18
U.S. Total	1.90	1.39	2.91	2.26	4.39	2.97	3.70	2.10

[a] In the West demand region, residential gas is assumed to compete with electricity instead of fuel oil. The long-run cross price elasticity is 0.25.

Price elasticities and rates of adjustment for the residential and commercial sectors are chosen to be roughly consistent with estimates in the econometric literature. (See Bohi, 1981, and Huntington and Soffer, 1982.) For the industrial and electric utility sectors, these parameters are somewhat higher in absolute value than implied by most econometric analyses. The increasing use of oil and gas dual-fired boilers in these sectors will make gas demands more sensitive than in the past to relative prices. Because of the scarcity of regionally disaggregated studies, it is assumed that the rates of adjustment and all price elasticities are identical cross regions within each demand sector.

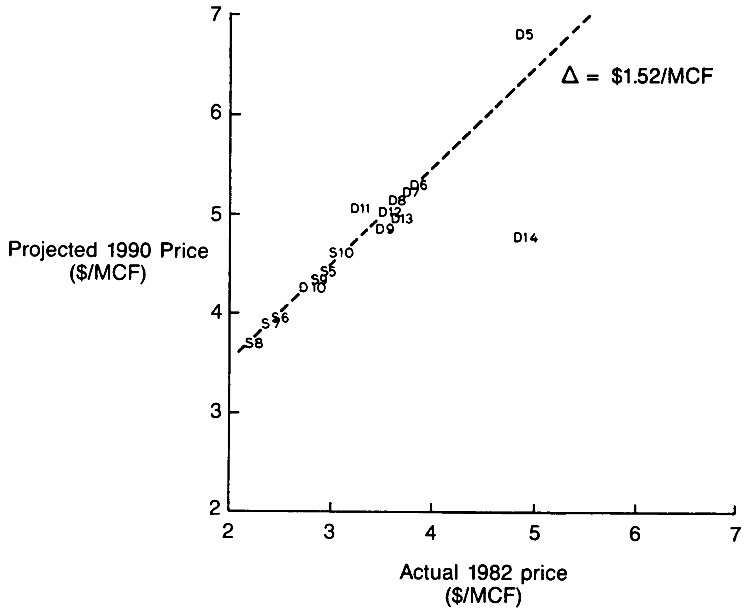
PROJECTIONS TO 1990

For projections to 1990, the general economic and energy sector conditions are adapted from the reference case of NEPP83. Accordingly, the international price of oil is about the same as in 1982 (measured in constant dollars). With deregulation, the Gulf Coast wellhead price rises from $2.48/MCF in 1982 to $4.00/MCF in 1990. We also assume that virtually no new gas pipeline capacity will be added to that existing in 1982.

Table 3 summarizes GTM's reference case results for the United States. These are regional projections of gas demands and prices in 1990, and they are compared with those prevailing in 1982. Overall, there is a 15 percent decline in gas consumption. The rise in GNP is more than offset by the rise in the price of gas relative to that of oil. The highest percentage of gas price increases occurs in those regions closest to the major sources of supply. Typically, demand declines in those regions.

Table 3. Comparison of GTM Projected U.S. Gas Demands and Prices for 1990 with Actual 1982 Levels

	Gas Demand (TCF)		*Gas Price (1982$/MCF)*	
Demand Region	*1982*	*1990*	*1982*	*1990*
5. New England	0.31	0.42	$4.87	$6.92
6. New York/New Jersey	1.21	1.19	3.83	5.35
7. Mid-Atlantic	1.19	0.87	3.76	5.38
8. South Atlantic	1.69	1.45	3.57	5.10
9. Midwest	3.77	3.10	3.51	4.99
10. South West	6.23	4.62	2.79	4.31
11. Central	0.98	1.02	3.29	5.11
12. North Central	0.60	0.77	3.56	5.08
13. West	2.02	1.80	3.68	5.01
14. Northwest	0.21	0.28	4.89	4.84
Total	18.21	15.52		



Note: D denotes city-gate prices; S, wellhead prices.

Figure 2. U.S. regional price differentials.

Because U.S. natural gas transportation network is highly interconnected, it is projected that virtually all regions will experience similar increases in the delivered level of gas prices between 1982 and 1990. This is shown graphically in Figure 2. Virtually all regions experience the same $1.52/MCF price increase as the Gulf Coast supply region. This diagram suggests that the U.S. gas market can be approximated by the price at a single point (e.g., the Gulf Coast) and fixed interregional differentials at all other supply and demand locations. One exception to this general rule occurs in the Northwest demand region. There the Gulf Coast is not a competitive source of supply. Another exception is New England, where there also is a region-specific transportation capacity bottleneck.

International trade flows are among the most instructive results from the 1990 Reference Case. Table 4 compares the 1990 export projections with the 1982 flows from Alberta/British Columbia. There is a shift in allocation of total Canadian exports among the several U.S. importing regions. Exports to the Midwest decline, and there is an increase in those to the West and Northwest. The third column of Table 4 indicates the cost penalties for perturbations in this equilibrium pattern of trade flows. A negative penalty identifies a link for which an increase in the flow rate would be beneficial. Data in this table suggest there could be sizable benefits from

Table 4. Alberta/B.C. Exports, by Region of Destination in the United States, 1990 Versus 1982 Levels

U.S. Demand Region	1982 Exports (TCF)	1990 Exports (TCF)	1990 Cost Penalty ($1982/MCF)	1990 Border Price ($1982/MCF)
5. New England	0.01	0.01	− $1.58	$5.19
6. New York/New Jersey	0.03	0.05	− 0.06	5.14
7. Mid-Atlantic	0.01	0	0.01	5.19
9. Midwest	0.26	0.17	0	4.79
12. North Central	0.04	0.06	− 0.24	4.39
13. West	0.30	0.43	− 0.12	4.49
14. Northwest	0.14	0.28	0	4.39
Total	0.79	1.00		

construction of additional pipeline capacity to carry gas from Canada to New England.

The last column of Table 4 shows projected market equlibrium prices at the border for the sale of gas into each demand region. Because GTM simulates the operation of a competitive market within the United States—and because it is assumed that Canada will not practice discriminatory pricing—there is a uniform netback price for gas in Alberta.

Canada's domestic gas transport costs vary from one U.S. border point to another, so the delivered price of gas cannot be uniform between these points. For example, the border price for sales into the West is $4.49/MCF, whereas for sales into New England, the border price is $5.19/MCF. Thus, when U.S. gas prices are deregulated, it will not longer be feasible to maintain the system of uniform border prices that prevailed during the 1970s and early 1980s.

Much of the gas now sold in the United States is subject to take-or-pay contracts. These require that a certain minimum fraction of the anticipated purchases of a particular gas consumer be taken at a prespecified price. It is difficult to obtain the data to simulate these contractual arrangements. GTM can, however, provide an estimate of the resulting inefficiencies in transportation.

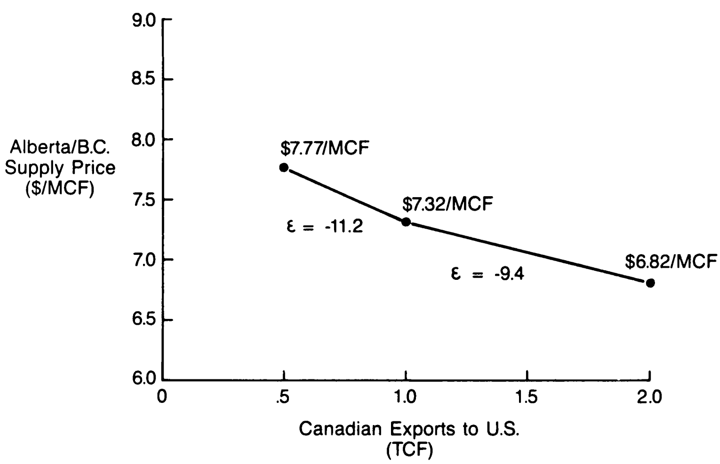
To illustrate this approach, we restrict each of the 1990 gas flows to at least 80 percent of their 1982 levels. Because of cross-hauling, this leads to additional costs of $567 million in 1990 ($0.038 per MCF of gas produced in the United States). Clearly, this understates the economic cost, for this estimate does not include a more serious inefficiency. Take-or-pay contracts encourage the use of high-cost gas despite the presence of unutilized low-cost sources of supply. To consider this feature, the present version of GTM would have to be modified to allow pricing based upon average rather than marginal costs of supply. In all likelihood, this extension would require the use of fixed-point or complementarity rather than optimization methods of solution.

PROJECTIONS TO 2000—CANADIAN EXPORT POLICIES

Two major factors—the resource base and the growth of domestic demands—will affect any economic analysis in the Canadian debates on long term gas policies. Both these elements are regarded as exogenous in GTM. Nonetheless, the model may provide useful insights into (a) the price elasticity of U.S. demands for gas imports from Canada and (b) the rate at which prices (or demand curves) are likely to move between 1990 and 2000.

Figure 3 illustrates our results on price elasticities. It shows the effect of varying the level of Canadian exports to the U.S. gas market. Our reference case (both for 1990 and 2000) is based upon a constant level of Canadian exports: 1.0 TCF. This leads to an Alberta netback of $7.32/MCF in 2000. Even if the level of exports were halved or doubled, the netback would change by only 5 percent. The U.S. price elasticity of demand is of the order of -10 for imports from Canada.

At first glance, this is counterintuitive. (Recall (from Table 2) that the U.S. long-run price elasticities for gas lie between -0.5 and -2.0 at the point of end use.) On second glance, however, Figure 3 becomes quite plausible. Roughly speaking, the price elasticity of demand for imports is inversely proportional to the market share supplied by this source. According to the reference case solution (Table 5), Canada supplies only 6 percent of the U.S.



Note: ε denotes the arc elasticity between two points.

Figure 3. Alberta/B.C. netbacks versus export levels, 2000.

Table 5. 2000 Equilibrium Flows (TCF) and Cost Penalties ($MCF)

From supply \ To demand	1 Mexico	2 Westcan.	3 Ont./Que.	4 Atlantic	5 New Eng.	6 NY/NJ	7 Mid-Atl.	8 S. Atlantic	9 Midwest	10 SWest	11 Central	12 N. Cntrl	13 West	14 NWest	Supplies Prices
1. MEXICO	2.20					0.07	0.07	0.07	0.07				0.03		2.60
	0.00					0.00	0.00	0.00	0.00				0.00		6.07
2. ALTA/BC		1.47	1.38		0.30	0.00	0.00		0.00			0.06	0.19	0.35	3.76
		0.00	0.00		−0.45	0.06	0.13		0.12			−0.12	0.00	0.00	7.32
3. ATLANTIC				0.20	0.10										0.30
				0.00	0.00										7.42
4. ARCTIC		0.00													0.00
		0.00													7.72
5. APPALAC						0.00	0.00		0.65						0.65
						0.00	0.00		0.00						7.43
6. US GULF					0.15	0.11	0.75	1.56	0.50	4.76					8.82
					0.00	0.00	0.00	0.00	0.00	0.00					7.01
7. MID-CON									1.24	0.00	1.07				2.31
									0.00	0.00	0.00				6.93
8. P. BASIN									0.12	0.00			1.42		1.54
									0.00	0.00			0.00		6.76
9. ROCKIES									0.31		0.00	0.95	0.05	0.00	1.31
									0.00		0.00	0.00	0.00	1.33	7.39
10. PACIFIC													0.47		0.47
													0.00		7.67
11. ALASKA									0.05						0.05
									0.00						2.00
Demands	2.20	1.47	1.38	0.20	0.55	1.17	0.82	1.62	2.95	4.76	1.07	1.01	2.16	0.35	21.71
Prices	6.32	7.72	8.22	7.42	8.92	8.36	8.29	8.11	8.00	7.32	8.12	8.09	8.02	7.97	

Note: Due to independent rounding, individual flows do not necessarily add to totals.

market in the year 2000. Moreover, U.S. production is price-responsive. For both of these reasons, demand is far more price-elastic for Canadian exports than for gas as a whole.

The elasticity results are robust. We have experimented with a wide variety of plausible scenarios, and the results are similar. If there is sufficient time for adjustment to alternative price levels, a deregulated U.S. market will be highly elastic with respect to the price of Canadian gas imports.

One qualification should be noted. According to the reference case solution for 2000, Canada will become a dominant supplier to New England and the Northwest. Except for the possibility of additional U.S. pipeline capacity, Canada might be able to exploit a low elasticity of demand in these isolated regions. This is the type of issue that tends to be overlooked if geographical details are neglected in broad-scope national analyses.

In the reference case, international oil prices rise between 1990 and 2000. Accordingly, the Alberta netback rises from \$4.19 in 1990 to \$7.32/MCF (both expressed in dollars of 1982 purchasing power). This is equivalent to an annual appreciation of 5.7 percent (in real terms, net of inflation).

Now consider the issues of whether it is best to extract additional gas from Alberta in 1990 or to delay its exploitation until 2000. If extraction costs are neglected and if there are high price elasticities of demand for exports, then 5.7 percent is the breakeven rate of return on this type of investment. That is, if Canadian capital costs lie below this value, it pays to defer exploitation from 1990 to 2000, or a later date. Conversely, if the cost of capital is higher than 5.7 percent, it is worthwhile to sell additional amounts of gas at the earliest date possible.

One could introduce additional factors to supplement this rough calculation. The presence of positive extraction costs would raise the breakeven rate of return. Small investors would require a higher rate of return than large firms or public-sector enterprises in Canada. Time lags could make a difference. U.S. import demands would be less price-elastic in 1990 than in 2000. Each of these factors may affect Canada's export decisions, but they are unlikely to be as crucial as the international price of oil.

ALTERNATIVE OIL PRICE SCENARIOS

Since gas and oil are close substitutes, any projections about natural gas markets must consider the uncertainties of the international oil market. In this section, we test the robustness of our 2000 reference case results with respect to two key oil-related parameters: the level of fuel oil prices and the responsiveness of gas demands to oil prices. Specifically, we consider two alternative sets of fuel oil prices and of cross price elasticities. The two oil price assumptions correspond to NEPP83 cases A (low price) and B

Table 6. U.S. Natural Gas Demands, Alternative Scenarios, 2000

	World Oil Price (1982 $/barrel)	Cross Price Elasticities		Gas Demand (percent change from reference value)
		Reference	Low	
Reference oil price	$57	16.46 TCF	16.24 TCF	− 1.3
Low oil price	36	15.89	15.88	− 0.1
Percent change from reference value	− 36.8	− 3.5	− 2.2	

Table 7. U.S. Gulf Coast Wellhead Prices ($/MCF), Alternative Scenarios, 2000

	World Oil Price (1982 $/barrel)	Cross Price Elasticities		Gas Demand (percent change from reference value)
		Reference	Low	
Reference oil price	$57	$7.01	$6.32	− 9.8
Low oil price	36	5.28	5.25	− 0.6
Percent change from reference value	− 36.8	− 24.7	− 16.9	

(the reference case). These correspond, respectively, to world crude prices of $36 and $57 per barrel in 2000 (in 1982 dollars). The alternative cross price elasticities are (a) the reference values and (b) low elasticities, with the reference values of the industrial and electric utility cross price elasticities each reduced by 0.5. These assumptions are combined into four scenarios used to ascertain the strength of the linkage between world oil prices and GTM's market-clearing gas prices and demands.

Tables 6 and 7 compare the four scenarios in terms of total U.S. demands and Gulf Coast wellhead prices. U.S. demands are singled out because Canadian and Mexican demands are exogenous; Gulf Coast prices are used because this is the largest producing region. It is clear that gas prices are more sensitive than gas demands to oil price movements. Under the reference elasticity assumptions, a drop in the world oil price of 37 percent is associated with a 25 percent decline in the Gulf Coast gas price but only a 3.5 percent drop in total gas demand. A similar though less dramatic conclusion holds true with low cross price elasticities. These results can be explained primarily by the fact that U.S. gas supply prices are projected to be highly inelastic. Large wellhead price declines are associated with small decrease in equilibrium production levels in 2000. (Recall Figure 3.)

These results are significant for Canadian export policy. Under the low world oil price assumptions, the Alberta netback (in 1982 dollars) rises from $4.19 in 1990 to $5.59/MCF in 2000, an average real annual increase of

2.9 percent. Only with a very low discount rate would it pay to defer gas exports under this scenario.

SUMMARY AND CONCLUSIONS

GTM focuses on long-term market equilibria rather than on short-term institutional and regulatory issues. The model is designed to study gas trade in the 1990–2000 time frame when today's complex system of U.S. wellhead price regulations should be almost completely phased out. Surely there will continue to be a need for government-to-government negotiations over gas trade, a motivation for our work on GTM.

Several broad conclusions emerge. One is that it is likely in the long run the price elasticity of U.S. demand for natural gas imports will remain high. Because domestic supplies will continue to cover most of the demand, the price elasticity of demand for imports will be considerably higher than that for gas as a whole. This general conclusion does not hold for all regions. Because of the lack of pipeline connections to other points within the United States, the Northwest is heavily dependent upon pipeline imports from Canada. A similar situation could arise in New England. Thus, it is possible that in the future Canada could have greater market power and might be able to practice discriminatory pricing in those two regions.

Another key conclusion is that variations in the price of oil are likely to have a much larger impact upon the price than the supply of gas. To the extent that North American gas supplies are inelastic with respect to price, aggregate demands will adjust to whatever quantities are available. Oil price movements will affect the price of gas but will not lead to large changes in the quantities bought and sold.

Beltramo (1985) has analyzed these issues using a more sophisticated demand submodel than employed here. Among other things, his submodel treats energy demands for heat and power in U.S. manufacturing separately from those in other industries. He estimates an econometric model of regional manufacturing energy demands that specifically allows capital-embodied adjustment to prices and fuel-switching between oil and gas in dual-fired equipment. His results confirm our previous conclusion that the U.S. demand for natural gas imports is highly price-elastic. Another conclusion is not robust. The effect upon gas prices of changes in the international oil price is found to be much smaller than reported earlier in this paper. This is a direct consequence of the econometric findings and revised submodel formulation. In Beltramo's submodel, the implicit long-run elasticity of gas demand with respect to oil price is much smaller than assumed here.

Because GTM is a static model, it cannot be used directly to assess the optimal timing of resource extraction. Indirectly, however, the model may be employed for this purpose. It provides gas price projections for the years 1990 and 2000, and these may be compared with the opportunity cost of capital during this decade. This is no substitute for a Hotelling-type analysis, but it is a first step in that direction. It remains to be seen whether one obtains useful additional insights by combining geographical and intertemporal details.

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