WHITHER LONG-TERM CANADA-U.S. NATURAL GAS TRADE?
A VIEW FROM THE (MODELLING) TRENCHES

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Abstract

How will long term Canada-U.S. gas trade evolve? Because of recent expanded Canadian gas exports to the U.S. this question has received much industry attention and it has also been addressed in the ninth study of Stanford University's Energy Modeling Forum. Drawing upon experience gained from participating in that study, this paper provides a modelling perspective on charting the course of future North American gas trade. The principal conclusion is that, due to major uncertainties arising from several sources, decision makers must exercise much caution when basing their decisions or judgments on outcomes from long-term gas trade models.

Introduction

The question posed in the title is perennial, regularly consuming substantial financial resources in the search for an answer. For recent perspectives, see Mossavar-Rahmani (1987), American Gas Association (1987) and Brown (1988). The question has also received renewed industry attention recently because of the rapid increase in Canadian gas exports to the U.S. and the very large sums of money that are at stake with expanding trade. In this paper the question will not be addressed directly, but it will be argued that whatever answer is provided by energy modellers must be strongly qualified and cautionary warnings provided to whomever uses the answer. This type of hedging, typical of most economic forecasting, is essential when projecting future gas trade. The arguments to support this cautionary stance rest on the interaction of geological, engineering, economic, political and environmental factors and how such factors should be represented in a modelling framework. At present these considerations appear collectively not subject to any clear resolution for forecasting the evolution of gas trade.

This paper draws upon experience gained as part of a study group assembled by the Energy Modeling Forum of Stanford University in 1986 to analyze North American natural gas markets. The final reports of this project, Energy Modeling Forum (1988, 1989a, 1989b) -- henceforth EMF 9 -- likely represent the most comprehensive analysis of the topic yet undertaken. Despite its impressive quality of analysis and number of specific conclusions, however, the study exhibits in each of its four scenarios a wide range of model outcomes for several measures of gas consumption and supply, most especially U.S. imports of Canadian natural gas and Canadian gas exports to the U.S.[1] Some of the differences among model outcomes are explained and much is learned from these differences.

It is the purpose of this paper, however, to discuss in detail why model outcomes differ, why it is unlikely that outcomes from different gas trade models need ever be closely similar, and why projecting the evolution of gas trade even with just one model must be interpreted cautiously.

The discussion rests partly upon the author's understanding of models used in EMF 9 which focus centrally on Canada-U.S. gas trade and not those primarily emphasizing U.S. demand-supply balances. Moreover, the need to model gas trade for making informed decisions on gas trade issues is regarded as vital. The circumstances of natural gas demand and supply in North America are so complex and many of the attendant policy issues so contentious that formal modelling is critical for deciding among conflicting claims or separating fantasy from plausible future. Any analysis of gas trade issues, whether it employs a formal model or not, must contend with critical unknowns and models provide a framework for representing such unknowns and quantifying their prospective importance.

This paper is directed toward diverse groups interested in North American gas trade: decision makers in private enterprises, energy ministries/public utilities and regulatory boards who base their judgments in whole or in part on gas model outcomes; novice model builders, who are unaware of the complexity of modelling international gas trade; seasoned model builders, who may not fully appreciate the range of possible outcomes from their own and related models; economic theorists of gas trade issues, who may share ignorance of the complexity of the phenomenon with novice model builders; and finally, researchers only peripherally involved in gas trade issues, such as regional economists or analysts of non-energy gas markets.

Various considerations important for analyzing long term gas trade are discussed in the three sections which follow and sundry implications for gas trade modelling are simultaneously provided. Summary observations are then offered and conclusions are drawn in the final section.

Fundamental Considerations

Some Technical Issues

Computational modelling of gas trade requires that a system of measurement be adopted. How should natural gas be measured? The volumetric method -- with common measures of thousand cubic feet (MCF), billion cubic feet (BCF) and trillion cubic feet (TCF) -- prevails in the U.S., but the heating content method -- with common measures of gigajoules (GJ), petajoules (PJ) and exajoules (EJ) -- is officially sanctioned by the National Energy Board (NEB) in Canada and other Canadian energy agencies. Moreover, heat content is usually considered what gas consumers demand. Given the size of the U.S. market relative to the Canadian market, trade issues most certainly will be examined in volumetric terms. Hence it is necessary to employ a heat-to-volume conversion ratio to make Canadian gas data compatible with U.S. data. In actuality, however, the appropriate conversion factor varies slightly across producing regions in Canada (and likely the U.S. as well) because of differing qualities of gas produced by region and differing amounts of natural gas liquids extracted in gas processing plants.

For many gas pipelines gas is used as pipeline compressor fuel. Hence delivery of a unit of gas from one source to several different destinations can require different amounts of gas for compressor fuel depending upon the locations of those destinations.[2] For instance, in Canada the delivery of one PJ of gas to Toronto from the Alberta border requires about 7% of a PJ for use in pipeline compressors. That 7% would not be necessary if the PJ were consumed in Alberta. This distinction cannot be represented solely as a matter of cost since it has implications for how rapidly gas reserves are used.

Although these technical issues are likely to be dwarfed in importance by other considerations, nevertheless they bear mentioning because a BCF of gas delivered from a Canadian source to a U.S. destination (e.g. from British Columbia to Washington state) may be slightly or even noticeably different in terms of heat content and gas fuel implications from a BCF delivered from a different Canadian source to another U.S. destination (e.g. from Alberta to New York).

Time Frame, Foresight and Terminal Conditions

Natural gas consumption and supply employ capital facilities such as furnaces, pipelines and gas processing plants which last a long time. Moreover, natural gas is a nonrenewable resource. Hence gas trade must be analyzed over a long time frame. Several modelling issues immediately arise: What time horizon to select? How long to make each time period prior to the horizon? What degree of foresight to attribute to sellers and buyers of gas? What terminal conditions to employ? Unfortunately, there appears to be no unambiguously correct answer to any of these questions and the models used in EMF 9 utilize different approaches.

Foresight can be modelled in several ways. First, by complete myopia, where decisions made at any time are unaffected by decisions taken later. This approach enormously simplifies the linkage of time periods and allows many details of consumption, transportation and production to be represented during each time period, but assumes that expectations about the future play no role in current decisions. Complete myopia about the future may be accompanied by no vision or some vision across differing markets during each time period. Second, by perfect vision within a time period across regions, but myopia over time. Perfect vision over regions means that each decision for a particular location is taken with regard to its impact on decisions in all other regions and leads to market-clearing price equilibria.[3] Third, by perfect foresight, or perfect vision within time and over time. In this case decisions at each location during each time period are taken in full knowledge of their implications for decisions in all locations and periods. This approach maximizes efficiency in allocating natural gas and endogenously computes the user costs of nonrenewable resource consumption, but typically requires a large model or one with a highly simplified structure. It also assumes a degree of vision for gas market participants which may not reflect past experience.

All three approaches may require a discount rate -- assumed by EMF 9 to be 10% real, post-tax -- but a discount rate is essential for models utilizing the third approach. What the discount rate should be and whether it should be constant over time remain open questions.

Simultaneously, a decision must be taken regarding the length of each time period. An annual period provides considerable time resolution but can generate a very large model unless the model is myopic. Different models used in EMF 9 employ time periods of one year, three years, five years and ten years.

Coupled with the issue of foresight is the question of terminal conditions, which convert an infinite-horizon problem into one with a finite horizon. Such conditions are intended to reduce or eliminate bias in intertemporal allocation decisions. Myopic models need not assume any particular terminal conditions because future events cannot influence current decisions. But models with foresight must employ explicit terminal conditions. Two possibilities are: truncation with amortization of capital costs, and endogenous transition to a backstop source of gas supply. For example, AGAS (see Quon and Wong (1988)) utilizes the former method, employing a horizon of 2007, but includes only amortized capital costs of consumption, pipeline construction and gas supply to prevent the bias in project selection that would occur if total capital costs were included. By contrast, Rowse and GRI-NA (see Rowse (1988) and Nesbitt et al. (1988), respectively) employ the latter method, which requires including enough time periods to ensure that transition to a backstop source of supply occurs endogenously. The latter method allows total capital costs of investment projects to be included but requires assumptions about the cost and availability of backstop gas, assumptions which provide additional sources of uncertainty.

Regional Disaggregation

Myopic models can and do exhibit very considerable disaggregation over space, but models exhibiting foresight typically trade off spatial disaggregation for time disaggregation (or vice versa). Regional disaggregation is important for capturing transportation cost differentials between regions (and thus the comparative advantages that certain supply sources have in meeting demands in particular locations) and the region-specific availability and cost of fuels that compete with gas (and thus the shape of regional gas demand curves). These considerations are discussed further below.

The Economic and Regulatory Environment

EMF 9 employs two different trajectories for world oil prices: an upper price path and a lower price path; see Energy Modeling Forum (1989b, pp. 1-72). Although problematic, assuming an explicit price path for crude oil is essential for designing a scenario for gas allocation. Crude oil prices bear on macroeconomic activity by nation and region, the ability of producers to fund investment projects, and the price of residual fuel oil, which is a close substitute for gas in certain markets. Macroeconomic forecasts are also essential for projecting demands for natural gas. Gross national products for the U.S. and Canada are forecasted in EMF 9, as are demographic variables such as population and households, all to 2010.

Pivotal to any study of gas trade is the U.S.-Canada currency exchange rate, specified by EMF 9 to be U.S. $0.75 per Canadian dollar, constant over time. It is worth noting that the Canadian dollar rose from an all-time low of U.S. 69.13 cents early in 1986 to a 6.5-year peak of U.S. 83.53 cents in July of 1988, a 21% rise in 2.5 years.[4] While the exchange rate may not exhibit this much volatility in future, nonetheless it is clear that this element has the power to exert major influence over the competitiveness of Canadian gas in U.S. markets and thus the evolution of future gas trade.[5]

Consistent with the tenor of the times, EMF 9 assumes a regulatory environment that is accommodating to market forces and characterized by reduced government involvement in gas markets. This assumption applies to the Canadian and U.S. Governments, all state and provincial governments, and all local regulatory boards. The assumption is adopted partly because few models contain elements to allow detailed representation of the regulatory environment. Whether an accommodating regulatory environment will prevail in future is unknown, but a decade ago the circumstances were very different. Moreover, EMF 9 cautions that some types of model outcomes could, if realized, cause political pressure to be exerted to roll back pro-competitive measures. In particular, rapid gas price increases could trigger such pressure.

Supply-Oriented Considerations

Prospective U.S. Supplies

Natural gas is frequently classified as conventional gas or nonconventional gas, each category having much diversity; see Office of Technology Assessment (1985) -- henceforth OTA (1985). Widely differing professional opinions exist over the size of the conventional and nonconventional resource bases, partly because of a paucity of good data, although this circumstance is changing; see Electric Power Research Institute (1987). Disagreements rest on geological, engineering, technological and economic factors, particularly with respect to the nonconventional sources of tight gas, shale gas and coal bed methane, which have not yet been exploited to any great extent. It has also been argued, quite plausibly, that resource supply curves for different types of gas may exhibit plateaus representing blocks of gas that become available at certain price threshholds because new technologies make such production economic. How rapidly such nonconventional supplies could be developed and the heights of the price plateaus appear highly uncertain, however, because investor wariness of untried technologies and cash-flow constraints would slow development of nonconventional supplies.

Another factor complicating projections of gas supplies is the reserves/production (R/P) ratio for different categories of gas. The rate at which gas reserves are produced depends on several factors, including production technology, reservoir characteristics, field maturity, conservation regulations, market demand, contractual agreements, liquids extraction, cash flow, and so on. Thus the R/P ratio for each type of gas can change over time as these factors change.[6]

To take one category of gas as an example, enhanced gas from maturing U.S. fields may prove to be quite responsive to price, for it depends on cost-sensitive considerations such as well spacing, infill drilling and compression: "OTA calculated the potential increase in recoverable gas from decontrol of the price-controlled fields, over and above increases already programmed into existing legislation, to be 19 to 38 TCF." (OTA(1985, p. 9)) Price decontrol has proceeded in the U.S. since 1978 and in the summer of 1989 the Bush Administration announced that all federal gas price controls would end by

January 1, 1993. Thus measures to produce enhanced gas are likely in the future as the gas bubble dissipates and gas prices edge upwards. Even if only the lower end of the OTA range is attainable, and even if only 1/40 of this gas is produced annually, enhanced gas still represents nearly 0.5 TCF/year that would not otherwise be available and could compete directly with Canadian gas in certain U.S. markets. Less conservative assumptions about the availability of enhanced U.S. gas suggest that this category of gas alone could slow the penetration of Canadian gas into U.S. markets or exert downward pressure on the prices that Canadian gas might fetch.

More generally, prospective supplies of gas from different categories exhibit considerable uncertainty, and OTA (1985, p. 9) cites the following plausible ranges for recoverable resources (in TCF): conventional gas (430-900+); tight gas (100-400+); Devonian shale (20-100+); and coal seam methane (20-200+). But OTA also cautions that "the magnitude of the unconventional gas recoverable resource base will increase substantially with higher gas prices and advances in recovery technology." Such projections, it should be noted, are disputed by various different corporations and energy agencies in the United States.

Integral to prospective supplies are finding and development costs, which are likely to differ according to field size. There is also debate over how much directionality is possible in exploration, but little doubt about the importance of rising oil prices for stimulating exploratory drilling. Such drilling may draw rigs away from searching for gas but at the same time may add to gas reserves as gas is found instead of oil (or with oil). An additional consideration, apparently captured by few models, is that finding costs tend to be correlated with oil prices as activity of the drilling rig fleet expands or contracts with exploration for crude oil. This behaviour was observed most dramatically in the wake of the 1986 oil price decline.

Other uncertainties are the cost and availability of gas from Alaska, especially the timing and cost of the Alaska Natural Gas Transportation System. At present, however, it appears that in the Lower 48 this alternative is dominated by Canadian gas from the Beaufort Sea/Mackenzie Delta and perhaps certain high cost alternatives in the Lower 48; see Nesbitt et al. (1988, p. 219).

For modellers the problems presented by such supply considerations are manifold; a variety of resource supply curves is plausible for each type of gas at each prospective supply location, and so are the rates at which production may occur from such resources once converted to reserves and the attendant production costs.[7] Since professional opinion is divided over basic geological, engineering, technological and economic considerations, it is not surprising that different models used in EMF 9 represent prospective supplies differently.

Prospective Canadian Supplies

Similar considerations arise with regard to the Canadian gas resource base. There is uncertainty about the conventional gas resource supply curve by region and several different representations are plausible.[8] Much greater uncertainty surrounds the potential of the tight gas resource base in Canada, however. Unlike the U.S., there is no Canadian track record of commercial success in producing tight gas and thus no imminent likelihood of producing tight gas in large volumes. The future behaviour of the R/P ratio is also in doubt. In the past because of government export regulations this ratio has been high, but with deregulation of Canadian gas markets it has been falling. Quon and Wong (1988, p. 316) report that the assumed Canadian R/P ratio is important for determining Canadian gas exports to the U.S.

Prospective supplies from the Beaufort Sea have their own characteristics. Arctic gas suffers from lumpiness and large transport costs associated with pipeline construction. While Arctic gas may well be the next large block of gas to provide Canadian supplies, nevertheless the matter of timing and cost is crucial. Few if any models capture well the essence of the burden of risk and the need for Arctic gas to provide supplies at high load factor to keep pipeline tariff rates low. Regulatory delays may also arise from the need to hold public hearings and other delays may accompany the settling of native land claims in Northern Canada.

Similar problems bedevil analysis of prospective Canadian gas supplies from Sable Island, off Nova Scotia. If Sable gas is developed, the bulk of supplies will likely go to the U.S. because the small domestic market is unlikely to warrant the high development costs. But this feature makes the development of Sable gas dependent on the demand for gas in New England and vulnerable to high tariffs associated with new pipeline construction. Again there is a substantial problem of lumpiness in investment and a need for risks to be shouldered.

Other Supply Matters

Mexican gas exports to the U.S. are unlikely during the next decade, but the post-2000 era may be different. By contrast, expanding U.S. gas markets may draw liquified natural gas (LNG) imports from North Africa, Norway or elsewhere. Despite a recent hiatus in LNG deliveries to the U.S., considerable expansion of LNG imports over the next several decades is conceivable. Unfortunately for modelling, such imports must be exogenous inputs because numerous factors beyond economics bear on LNG exports from gas producing countries. As with pipeline construction, the shouldering of risk is important for LNG trade.

Virtually no attention is devoted in EMF 9 to the importance of royalty/tax structures for gas trade and each modeller was advised to retain whatever representation was already employed. For instance, Rowse includes no royalties or taxes but AGAS includes royalties that vary by vintage of gas field. Apparently no model attempts to capture the complexity of royalty/tax structures exemplified by sliding royalties, bonus bids and leasing arrangements. Neither does any modeller examine the influence of changes in such structures on gas trade. Given past experience with altered royalty and tax regimes in Canada, however, it is unreasonable to expect that no changes will occur in future. Adequate representation of detailed micro royalty/tax structures at an aggregate level for analyzing gas trade issues constitutes a fundamental (and formidable) challenge for modellers.

Demand-Oriented Considerations

Regional Disaggregation and Demand Price Responsiveness

As mentioned above, regional disaggregation is important for capturing the functioning of gas markets. The EMF 9 models all employ different regional disaggregations and each chooses different decompositions among consuming sectors as well. For example, residential consumers tend to have the fewest supply alternatives and hence the least responsiveness to price, while industrial consumers tend to have the most supply alternatives and hence the greatest responsiveness to price. Recognition of demand price responsiveness is essential for long term analysis because of the fuel switching that has occurred in past owing to price changes and the observed past sensitivity of U.S. gas consumers to high-priced Canadian gas. In this regard, Rowse utilizes a single price-responsive consuming class in each region, while AGAS, GRI-NA and GTM use more than one. GTM in particular employs a complex approach to representing the demands of four consuming sectors in each region to capture the alternatives available to each sector; see Beltramo et al. (1986). AGAS also distinguishes among consumer classes. GRI-NA distinguishes between the core and noncore markets in each region and Nesbitt et al. (1988) explain why representing this distinction is crucial to whether endogenously-determined gas prices follow residual fuel oil prices on a heating basis or diverge from them.

Other issues also arise in choosing a representation of gas demands. Measured price elasticity increases the closer are demands to the burner tip because the presence of margins for gas distribution tends to lower the wellhead price elasticity; see Sweeney (1984). Furthermore, in markets where fuel switching capability is low, gas demands may be closely tied to the gas-using capital stock and this stock only adjusts slowly over time. Hence it is plausible to represent gas demand as the sum of captured demand and flexible demand, as does Rowse. GTM also employs a mechanism which captures sluggish adjustment in gas demand over time. Another consideration is that natural gas demand may depend on past prices, as well as the current price. Econometric specifications of gas demands frequently employ past prices in an effort to capture the importance of lagged adjustment. No model used in EMF 9 explicitly represents such lagged prices in demands; to do so would likely expand model size or solution time significantly, perhaps prohibitively.[9] Finally, current demands should likely depend on future prices (or expected future prices) but no model captures such a relationship either.

For the modeller there appears to be no best way to disaggregate among regions, to represent demands within a region or to capture the behaviour of demands over time. Representing some price responsiveness is critical and in general a distinction among consuming classes or between core and noncore markets is desirable. Beyond such comments, modelling practice appears to provide little guidance. What distinction among consuming classes to employ, which functional forms to choose and how to parameterize them all involve professional judgment since the available econometric evidence is not only ambiguous but also none of it may apply directly to the formulation chosen by the modeller. Thus a variety of approaches is plausible and no single approach dominates all others.

Impact of Regulatory/Legislative Changes

Some issues arise which are strongly micro-oriented and not easily captured in a long term modelling framework. Among them are the impacts of decisions at the local and state levels involving regulation of pipelines and local distribution companies. Certain regulatory decisions about how costs can be allocated may well affect local demands for gas but many of these decisions are at too low a level to be explicitly incorporated into a model focussed on long term gas trade. Moreover, how the dispute in Canada between Ontario and Alberta over pricing in the core market is settled will bear partly on future gas trade with the U.S.

Other issues loom which may bear strongly on future gas demands. The next decades will likely witness mounting concern for the environment, leading to government legislation to reduce auto emissions to improve air quality; to reduce emissions contributing to acid rain and to reduce CO_2 emissions to slow the onset of the "greenhouse effect." Such legislation may stimulate demand for natural gas but predicting the intensity, timing and location of the effects is impossible. The prospective importance of legislation to reduce acid deposition is recognized in EMF 9 and analyzed in part by a high demand scenario. Different models display widely differing gas trade outcomes but on balance the results are noticeably different from the base case scenario. Consequently, more stringent environmental standards than those assumed could substantially enhance the demand for Canadian gas in U.S. markets, particularly if restrictions simultaneously emerge on how rapidly U.S. gas supplies can respond to higher gas prices owing to curbs on offshore production or cost increases due to stiffer regulations for disposing of drilling wastes. Natural gas demand could also benefit from restrictions on expanding nuclear generation of electrical energy in circumstances where coal-fired generation is disfavoured by environmental legislation.

Finally, there is always the possibility of sudden legislation to cope with rapidly rising gas prices. Past experience suggests that price controls or royalty/tax changes are possible government responses to rapid gas price increases.

Concluding Remarks

Enormous complexity attends the supply, demand, transportation, regulatory and fiscal matters pertaining to North American natural gas trade. Even brief exposure to these circumstances compels the conclusion that adopting an explicit comprehensive modelling framework is vital for quantifying the impact of these matters on gas trade. However, participating in the ninth study of the Energy Modeling Forum leads to several observations about modelling and projecting Canada-U.S. gas trade:

- Different modelling approaches are possible, each exhibiting a different time frame, length of time periods, regional disaggregation and foresight regarding the future. No single approach appears to dominate all others in terms of "correctness" of answers which can be provided.

- Foresight may be modelled in terms of complete myopia, perfect vision across markets within time but myopia over time, or perfect foresight. Which way is best is unknown but perfect foresight is necessary to measure the user costs of natural gas consumption in accordance with economic theory. If perfect foresight is adopted, it is not known which type of terminal conditions is best to employ. Different modelling of foresight and terminal conditions likely contributes, albeit in unknown ways, to different model outcomes in EMF 9.

- There is considerable diversity of professional opinion about prospective gas supply sources in the U.S. and Canada, their responsiveness to increasing gas prices and how rapidly these prospective sources may be exploited.

- Representing prospective supplies in a model requires deciding on functional forms and their parameterizations for gas resource supply curves at all prospective supply locations and assumptions regarding what R/P ratios prevail over time. Assumptions must also be made (implicitly or explicitly) regarding whether the drilling rig fleet can support whatever drilling rates are determined over time by the model. There appears no professional consensus regarding what type of functional form(s) should be employed, whether they should contain plateaus and, if so, where such plateaus should be located. Constraints on developing nonconventional supplies are likely as important as whether there exist price threshholds for providing gas from these sources. Moreover, R/P ratios have varied in past and one model in EMF 9 found that assuming different R/P ratios can have a substantial impact on Canadian gas exports. Finally, expanded U.S. LNG imports are possible and likely, but such imports must be exogenous inputs in current models of Canada-U.S. gas trade.

- Representing future gas demands requires deciding on functional forms and their parameterizations and what lag structures to include (if any), and what types of distinction to draw among consuming classes, captured versus flexible demand and core versus noncore markets. Demand trends must also be based upon the path of world oil prices, the pattern of GNP growth by region (and nation) and demographic factors such as population and households, all over a time frame of several decades. No single approach to representing gas demands appears to dominate all others and the accuracy of various projections entering into parameterizing the demand functions over time is necessarily open to question.

- Current gas trade models appear ill suited for analyzing various transportation issues, some of which may prove central to expanded gas trade. Construction of new pipelines from the Canadian Arctic, Sable Island and elsewhere in North America involves lumpiness and risk sharing that appear to be captured poorly in these models.

- There are several phenomena, primarily regulatory and legislative in nature, which are exceedingly difficult to capture accurately in a model oriented toward long term gas trade. Yet these matters may, collectively, bear strongly on the evolution of gas trade.

- All models exhibiting foresight require a discount rate to aggregate and compare revenues, costs and benefits over time, as do some or all myopic models. All models require assumptions about the Canada-U.S. currency exchange rate over time. What the discount rate and exchange rate should be and whether they should be constant over time are open questions.

- Much uncertainty attaches to certain events that could have a major impact upon prospective gas trade, such as: growing environmental concern leading to legislation which effectively increases natural gas demands; future turbulence in world oil markets; introduction of an oil import tariff in the U.S. or the levying of a gasoline tax; efforts to reregulate by governments or public utility commissions in response to rapidly rising gas prices; and reintroduction of gas price ceilings or altered royalty/tax regimes. Some of these events appear to have a high probability of occurring over the next two or three decades.

Together these observations suggest that a wide constellation of futures for Canada-U.S. gas trade is plausible. EMF 9 examines four different scenarios and focusses both on outcomes across different models and across scenarios, paying particular attention to conclusions which appear common across models. A review of the issues to be addressed in formulating a gas trade model suggests that: given the diversity of approaches and the numerous assumptions necessary for each approach, different results should be expected, as EMF 9 finds, and given the four different scenarios, different results across scenarios by each model should be expected, again as EMF 9 finds. But perhaps at least as important, given a variety of other scenarios regarding world oil prices, the Canada-U.S. currency exchange rate, the discount rate, evolution of demands, prospective gas supplies and R/P ratios which are plausible but were not examined, a welter of other differing results should be expected. This expectation should hold for all models incorporating a single scenario and also for each individual model across many different scenarios. Consequently, any decision maker who relies upon quantitative projections from a model of long term gas trade for taking decisions must realize how fragile the results may be, even if sensitivity analysis supports the conclusions drawn. Caution in interpreting the results from a long term gas trade model is therefore vital.

Since the conclusion of EMF 9, one of the models used -- GRI-NA -- has evolved considerably. Because of its potential widespread availability, its appeal on economic grounds (it computes user costs endogenously), and its extensive validation, this model may become the de facto standard for analyzing the evolution of Canada-U.S. gas trade. As with all such models, however, it requires numerous assumptions and parameter estimates, to some of which considerable uncertainty may attach. Certain of the demand and supply elements discussed above are prime examples. Consequently, the user of model outputs must be cautioned regarding how closely tied the results may be to the assumptions made and not tempted to generalize the results beyond what appears warranted.

Regardless of the model used, in the quest for definite answers to support their judgments, some decision makers may inadvertently make unsupported generalizations of model outcomes. Alternatively, to avoid the ire that may accompany conclusions which are heavily qualified, model analysts may be tempted to make such unsupported generalizations of model results or minimize the probability (or importance) of alternative outcomes. The risks of this behaviour are obvious. If possible, perhaps the best approach is to append to any conclusions resting on model results a range of possible losses that could be incurred if a particular decision is taken on the basis of a future which fails to materialize as expected.

Although EMF 9 studies North American natural gas markets, many similar issues arise with regard to European gas markets. Following the logic of the above comments, there appears every reason to urge caution upon decision makers who draw conclusions about European gas trade from long term gas trade models encompassing Western Europe, Eastern Europe, Scandinavia, the Soviet Union, North Africa and the Middle East.

Finally, the preceding discussion bears on how the energy accords of the Canada-U.S. Free Trade Agreement (FTA) are viewed. During the 1988 Canadian federal election, which hinged on the FTA, the energy accords were criticized by opponents of the FTA as a sellout of Canadian interests to the U.S. Although the term sellout, like beauty, exists largely in the eye of the beholder, it appears that the long term future of Canada-U.S. natural gas trade as revealed by gas trade models and analysis is so indistinct as to defy any firm conclusion that for gas, the agreement is a sellout for Canada, a bonanza, or anything between these extremes. Given the past experience of mutually beneficial gas

gas trade between Canada and the U.S. and the plausibility that this will continue, the onus rests on the opponents of the FTA to provide persuasive arguments -- as opposed to rhetoric -- that for natural gas the agreement must constitute for Canadians anything like a sellout of Canadian energy interests to the U.S.

<u>Footnotes</u>

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1. See, for instance, Energy Modeling Forum (1989a, pp. 70, 78, 87, 95 and 96) and Energy Modeling Forum (1989b, pp. 416, 417).

2. Compressor fuel use also depends on the load factor at which gas moves, but this dependence is ignored here.

3. GTM adopts this approach. See Manne (1988).

4. <u>Calgary Herald</u>, September 7, 1988, p. F3.

5. Exchange rate fluctuations assume greater importance when it is understood that royalties (in Canada) and pipeline tariffs vary little or negligibly with the exchange rate, and thus changes in the exchange rate imply far larger percentage changes in wellhead netbacks. Hence exchange rate variations can have much impact upon the incentive to explore for and produce gas.

6. See Office of Technology Assessment, Congress of the United States (1985, pp. 93-96) for illuminating discussion of R/P ratios and a graph of these past ratios for the Lower 48 states.

7. Another complicating factor is the value of natural gas coproducts. This value varies directly with crude oil prices and effectively reduces gas production costs.

8. For instance, AGAS uses a step function for each resource supply curve, while Rowse (1986) utilizes a linearly rising supply curve and Rowse (1987) utilizes an exponential supply curve for several of his analyses.

9. However, myopic models can and do capture the influence of past prices implicitly by including lagged dependent variables in the demand functions employed.

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