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TOWARD THE INTEGRATION OF CANADIAN AND UNITED STATES NATURAL GAS IMPORT POLICIES

*Dennis C. Stickley**

As the United States and Canada move to deregulate the natural gas market, economic forces will begin to determine supply and demand levels of natural gas. In a two-part article, the author discusses the two countries' efforts to integrate their natural gas import policies. The first part, printed at 25 LAND & WATER L. REV. 145 (1990), *dealt with the background of the United States and Canadian natural gas policies, the countries' differing perspectives on the natural gas market, and the legal and institutional environment in the United States. The second part, printed here, deals with the legal and institutional environment in Canada, the U.S.-Canada Free Trade Agreement, and issues for the future of the cross-national natural gas market.*

V. THE INSTITUTIONAL ENVIRONMENT IN CANADA

In order to understand the procedure for exporting Canadian natural gas, it is helpful to review the Canadian statutory and administrative framework developed for this purpose. Stated briefly, this framework represents a synthesis between market forces and governmental policy.

During the past decade a transformation in economic regulation of natural gas exports has taken place. After record export levels, which exceeded 100 billion cubic feet (BCF) in some years in the 1970s, the volume of natural gas exported from Canada to the United States went into a steady decline.[1] At this juncture, federal and provincial governments embarked upon a deliberate course of deregulation.[2]

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1. OFFICE OF INTERNATIONAL ENERGY ANALYSIS, U.S. DEPT. OF ENERGY, U.S.-CANADA GAS TRADE REVIEW 8 (Nov. 1987).

2. NATIONAL ENERGY BOARD, A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING

The cornerstone of this effort came in the form of the intergovernmental *Western Accord* between the national government and the major natural gas producing provinces.[3] The unilateral federal decontrol of natural gas exports reached its culmination in September 1987, when the National Energy Board removed the requirement that exporting Canadian producers maintain a fifteen year gas supply reserve for domestic use before approval would be given for exports to the United States.[4] This institutional transition, as well as the details of the current regulatory scheme, are discussed in the following sections.

A. The National Energy Board Act

Administrative authority for the control and approval of natural gas exports is derived from enabling legislation adopted by the Canadian Parliament on November 2, 1959 in the form of the National Energy Board Act (NEBA).[5] This statute created the National Energy Board (NEB), on whose behalf the Minister of Energy, Mines, and Resources reports to Parliament.[6]

The NEB functions in both a regulatory and advisory capacity.[7] In fulfilling its advisory role, the NEB studies and reviews matters under the jurisdiction of the national government that concern:

> [T]he exploration for production, recovery, manufacture, processing, transmission, transportation, distribution, sale, purchase, exchange, and disposal of energy and sources of energy within and outside of Canada.[8]

The NEB has an equally broad array of regulatory authority over natural gas transmission. Pipeline construction must be done under Certificates of Public Convenience and Necessity when they connect a province with another province or "extend beyond the limits of a province."[9] Pipeline rates, or "tolls," are subject to NEB approval as well.[10]

The control of natural gas exports is administered by the NEB through a licensing system. NEBA provides in pertinent part:

AND TRANSMISSION OF NATURAL GAS, PIPELINE REVIEW PANEL ESTABLISHED PURSUANT TO CLAUSE 25 OF THE AGREEMENT AMONG THE GOVERNMENTS OF CANADA, ALBERTA, BRITISH COLUMBIA AND SASKATCHEWAN ON NATURAL GAS MARKETS AND PRICES OF 31 OCTOBER 1985 at 3 (June 1986).

3. *Id.*

4. *See generally,* NATIONAL ENERGY BOARD, REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES (July 1987).

5. National Energy Board Act, R.S.C. ch. 46 (1959).

6. *Id.*

7. Hodgson, *Digest of Mineral Laws of Canada, Mineral Report No. 13,* DEPARTMENT OF ENERGY, MINES, AND NATURAL RESOURCES (1967).

8. R.S.C. ch. 46, § 22.

9. *Id.* § 25.

10. *Id.* §§ 50, 61.

Gas and Power

Except as provided in the regulations, no person shall export any gas or power or import any gas except under the authority of and in accordance with a license issued under this part.

* * *

Issue of Licenses

(1) Subject to the regulations, the Board may issue licenses upon such terms and conditions as are prescribed by the regulations,

(a) for the exportation of power or gas. . . .[11]

Construction of the pipeline system for transporting natural gas licensed for export must also be done under a NEB certificate.[12] The EBA establishes the following factors to be considered in such approvals:

1. The availability of natural gas;

2. existing or potential markets;

3. opportunity for Canadian participation in financing, engineering, and construction; and

4. whether the project is in the public interest.[13]

Upon receiving an application for an export license, the NEB reviews all considerations that appear to be relevant to its decision. NEBA criteria for making this determination are as follows:

(a) [T]he quantity of gas or power to be exported does not exceed the surplus remaining after due allowance has been made for the reasonably foreseeable requirements for use in Canada; and

(b) the price to be charged by an applicant for gas or power exported by him is just and reasonable in relation to the public interest.[14]

The NEB adopted specific regulations implementing NEBA policy for approving export applications.[15] Under the NEB's Part IV Regulations, an applicant for an export license is required to submit a list of information in support of its application, including:

1. The number of years for which the application is made;

2. the annual, maximum daily, and total quantity of gas to be exported;

3. market requirements in Canada and outside of the country for domestic, commercial and industrial use both on a firm and interruptible basis;

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11. *Id.* §§ 81, 82.
12. *Id.* § 44.
13. *Id.*
14. *Id.*
15. National Energy Board Part IV Regulations, CAN. CONS. REGS. ch. 1056 (1986).

4. copies of sales and export contracts;

5. a summary of gas quantities purchased and the location of reserves;

6. evidence of removal authorization from provincial authorities;

7. evidence that the export volumes are surplus to Canadian requirements; and

8. the route, design, and capacity of the pipeline systems transporting the gas.[16]

Orders approving exports are issued upon terms and conditions set at the NEB's discretion.[17] Authorizations are usually effective for up to twenty-four months, but small transactions may be approved for a period of twenty years.[18]

Current long-term approvals are subject to rules that state:

> (a) [T]he order shall be granted subject to condition that the price to be charged for gas reported under the order shall not be less than the price to Canadians for similar types of service in the area or zone adjacent to the point of export;
>
> (b) the order shall not come into force until the person authorized by that order has filed with the Board, proof of authorization to move the gas outside the province in which the gas is produced, extracted, recovered or manufactured.[19]

If the contract is for a period of more than one month, it must include a provision permitting its termination if the exports are restricted by the Canadian government.[20] Exporting pipelines or producers previously had to show the NEB that they had a fifteen-year gas supply adequate for projected domestic needs before the requested export could be executed.[21]

Since Canada is a federation, national and provincial governments have overlapping jurisdiction in the regulation of natural resources.[22] The major energy resources are owned by the province, with federal

16. *Id.* at § 4.
17. *Id.* at § 8.
18. *Id.*
19. *Id.* at § 8(3).
20. *Id.* at § 4(a).
21. NATIONAL ENERGY BOARD, REASONS FOR DECISION, IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING (April, 1986):

> A Reserves : Production ratio (R/P) of 15 was selected because it would provide a minimum period of two - three years of level production before the productive capacity of the Western Canada Sedimentary Basin would commence to decline. Previously, the 25 A1 Reserves Formula adopted by the NEB in May 1982 required 25 times the current year's Canadian demand.

Id. at 4, 74, 79.

22. Hodgson, *supra* note 7 at 41.

powers controlling prices and volumes of energy sales between provincial or export markets.[23] Federal authority over interprovincial and export trade was granted under Canada's constitution.[24] Although the provinces cannot directly regulate this trade, they heavily influence gas trade through the issuance of removal permits.[25] In the face of this shared jurisdiction, gas pricing has been worked out through a series of negotiations in the 1970s and 1980s between the federal government and the producing provinces of Alberta, British Columbia and Saskatchewan.[26]

In order to set the level of exports, the NEB employed both a "Reserves Test of Formula" from 1960 to 1986 and a "Deliverability Test of Appraisal" between 1979 and 1986.[27] The "Reserves Formula" set aside an amount of established reserves equal to twenty-five times the current year's domestic demand, plus the maximum volumes that could flow under existing export licenses. Excess volumes were deemed surplus and thus available for export. The multiple of twenty-five related principally to the term of export licenses issued in the NEB's early years, when lengthy license terms were required in order to finance new pipeline facilities.[28] The "Deliverability Appraisal" compared the NEB's best estimate of future natural gas supply and demand on a year-to-year basis. The supply and demand information used in the appraisal included supply from established reserves, estimated future reserve additions, and expected Canadian requirements as well as estimated exports under existing licenses (i.e., the export volumes expected to flow).[29]

B. *Administrative Decontrol*

It is significant that the decontrol of Canadian natural gas exports was achieved without amending NEBA. However, a recent intergovernmental panel has suggested statutory changes because:

> The need to amend pricing regulations and to obtain an order from the National Energy Board to accommodate each new purchase and sale transaction are unnecessary impediments in a market-oriented system.[30]

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23. The three major natural gas producing provinces are Alberta, British Columbia and Saskatchewan. NATIONAL ENERGY BOARD, NATURAL GAS MARKET ASSESSMENT at 17-19 (Oct. 1988).
24. CANADA CONST., art. VI, § 91, cl. 2; 92A (1867, amended 1949).
25. NATIONAL ENERGY BOARD, MEMORANDUM TO ALL EXPORT LICENSE HOLDERS: REGULATORY PROCEDURES AND INFORMATION REQUIREMENTS FOR APPLICANTS FOR CHANGES TO EXISTING NATURAL GAS EXPORTS SALES CONTRACTS AND LICENSES (Oct. 2, 1984).
26. IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING, *supra* note 21 at 69-75.
27. *Id.* at 25.
28. *Id.*
29. *Id.*
30. MERRILL LYNCH, PIERCE, FENNER & SMITH, NATURAL GAS MONTHLY: A CANADIAN PERSPECTIVE at 1 (Oct. 1985).

NEBA was amended under a consolidation which revised the section numbering.[31] Most recently, NEBA was amended to reflect the adoption of the *Canada-United States Free Trade Implementation Act.*[32] These changes are intended to give the NEB authority under Article 904 of the Free-Trade Agreement (FTA) to only impose restriction on the exportation of energy goods going to the United States under narrow conditions.[33] The current state of administrative deregulation was largely achieved in a sequence of four steps. These milestones are discussed in the following sections.

1. Directly Negotiated Prices

The first breakthrough came in the key pricing arena. Export applications had always required specific NEB price approvals.[34] A dichotomy existed under former NEB policy because even though the actual volume of natural gas exported declined dramatically between 1979 and 1984, the total quantity of natural gas authorized for export under existing long-term arrangements actually increased.[35] As a departure from this practice, in July, 1984, the NEB announced it would eliminate the requirement that border prices be uniform, and would approve export contracts which were executed on the basis of negotiated contract prices.[36] Under this declaration the NEB would approve a long-term negotiated export price if the applicant could make several showings. First, the contract price had to be sufficient to recover an appropriate share of fixed costs incurred.[37] Second, the export price could not be below the wholesale price at the Toronto City-gate.[38] Third, the price could not be lower than that of major competing energy sources (primarily natural gas) in the United States.[39] Fourth, the contract had to include provisions which would account for changing market conditions during the term of the contract.[40] Fifth, the contract needed to contain provisions that provided reasonable assurances that the volumes committed under the contract would be taken.[41] Sixth, producers supplying the natural gas to be exported needed to endorse the conditions of the original agreement and any subsequent revisions.[42] Finally, exist-

31. CAN. REV. STAT. ch. 46 §§ 1911.1-1911.5.
32. *Id.*
33. *Id.*
34. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1, at 28.
35. *Id.*
36. NATIONAL ENERGY BOARD, REGULATORY PROCEDURES AND INFORMATIONAL REQUIREMENTS FOR APPLICANTS FILING FOR CHANGES TO EXISTING NATURAL GAS EXPORT CONTRACTS AND LICENSES (Oct. 2, 1984) at 2. The uniform border price was originally sought by the United States in order to remedy overpricing of Canadian exports. *Canada Moving to Capture Bigger Slice of U.S. Gas Market,* OIL & GAS J. at 57, 58 (Jan. 28, 1985).
37. REGULATORY PROCEDURES AND INFORMATIONAL REQUIREMENTS FOR APPLICANTS FILING FOR CHANGES TO EXISTING NATURAL GAS EXPORT CONTRACTS AND LICENSES, *supra* note 36 at 3.
38. *Id.*
39. *Id.* at 4.
40. *Id.*
41. *Id.* at 6.
42. *Id.* at 2.

ing contracts that were renegotiated under the new policy had to demonstrate that the economic return to Canada was enhanced.[43]

Significantly, several criteria were established for short-term sales contracts for the first time.[44] The following factors were applied by the NEB in approving sales in the emerging spot market:

1. The previously discussed factors for negotiated long-term contracts had to be met;

2. the contract term could not exceed 24 months;

3. total export volumes could not exceed 106 BCF;

4. all short-term sales had to be incremental and could not displace exports moving under long-term licenses; and

5. sales would be made on a best-efforts interruptible basis so as not to preempt the potential for long-term contracts or to commit pipeline capacity.[45]

2. The Western Accord

The next and most significant step in decontrol came through interaction between Canadian federal and provincial governments. On March 29, 1985 the *Western Accord* between the governments of Canada, Alberta, British Columbia and Saskatchewan was announced.[46] This landmark agreement covered issues concerning the pricing and taxation of oil and natural gas by the signatory bodies. At the time it was seen as the Canadian decontrol equivalent of the United States Natural Gas Policy Act (NGPA).[47] The *Western Accord*'s most significant features as they concerned natural gas exports are discussed in the following sections.

Natural gas deregulation. Originally, a natural gas deregulation scheme was scheduled to be implemented on November 1, 1985, by replacing the Toronto wholesale price floor with regional price references.[48] However, Canadian Energy Minister Pat Carney placed the onus on the industry to devise a market-oriented pricing policy that would be acceptable to all parties involved—producers, pipelines, distributors, consumers, and local government agencies as well as the Canadian federal government.[49] Under the new policy, as of Novem-

43. *Id.*
44. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 4 (March 1, 1985).
45. REGULATORY PROCEDURES AND INFORMATIONAL REQUIREMENTS FOR APPLICANTS FILING FOR CHANGES TO EXISTING NATURAL GAS EXPORT CONTRACTS AND LICENSES, *supra* note 36 at 2.
46. THE WESTERN ACCORD, AN AGREEMENT BETWEEN THE GOVERNMENTS OF CANADA, ALBERTA, SASKATCHEWAN AND BRITISH COLUMBIA ON OIL AND GAS PRICING AND TAXATION (March 25, 1985).
47. *Canada Moving to Capture Bigger Slice of the U.S. Gas Market, supra* note 36 at 62.
48. REASONS FOR DECISION, IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING, *supra* note 21 at 3.
49. THE WESTERN ACCORD, *supra* note 46 at 1.

ber 1, 1986, the price of natural gas exported to a certain region of the United States must not exceed that paid by Canadians "living in the area or zone adjacent to the export point."[50] A regionalized pricing procedure, for example, requires that exports at Niagara Falls, Ontario would be compared to the Toronto price (the former national standard) while natural gas entering at Kingsgate, Del Bonita or Monchy would track the price in Calgary, and gas brought in from British Columbia at Sumas or East Port would be referenced at the rates for Vancouver.

Fiscal measures. Perhaps one of the most important parts of the *Western Accord* is the removal of a number of fiscal impediments to the Canadian energy industry's recovery. In order to help stimulate investment in the oil and gas industry, the Canadian federal government agreed to remove numerous taxes or charges implemented by the Liberal government, including the Natural Gas and Gas Liquids Tax, the Canadian Ownership Special Charge, export charges on crude oil and crude oil products, the Petroleum Compensation Charge, and the Petroleum Gas and Revenue Tax.[51]

Provincial fiscal restraint. An important facet of the *Western Accord* was the pledge of the provincial governments to allow the benefits resulting from the agreement to reach the Canadian oil and gas industry. This was done to ensure that a series of new taxes and royalties would not be adopted.[52]

3. Agreement on Markets and Prices

Shortly after the *Western Accord* was adopted, another intergovernmental agreement was signed and became the third step in the four-part decontrol process.[53] This agreement was effective on November 1, 1985. The policy of the national government and the three major natural gas producing provinces was revised to permit domestic natural gas sales prices to be set through negotiation between buyers and sellers.[54]

Export sales were also affected by this agreement. First, the government of Canada, through the NEB, amended its policy for export license approval to only require satisfaction of the following "Criteria of Acceptability":

1. The price of exported gas must recover its appropriate share of incurred costs;

2. the price of exported natural gas could not be less than the prices charge to Canadians for similar types of service in the area adjacent to the export point;

50. *Id.* at 4.
51. *Id.* at 5.
52. *Id.* at 7.
53. AGREEMENT AMONG THE GOVERNMENTS OF CANADA, ALBERTA, BRITISH COLUMBIA AND SASKATCHEWAN ON NATURAL GAS MARKETS AND PRICES (October 31, 1985).
54. *Id.*

3. export contracts had to contain provisions to permit adjustments according to changes in market conditions;

4. exporters had to give reasonable assurances that contract volumes would be taken; and

5. exporters had to demonstrate that gas producers supplying gas for export endorse the terms of the contract and its subsequent amendments.[55]

An additional commitment was made by Ottawa for the appointment of an impartial panel to conduct an "all encompassing review of the role and operations of interprovincial and international pipelines engaged in the buying, selling and transmission of gas."[56] The Pipeline Review Panel submitted its report to the Minister of Energy, Mines and Natural Resources on July 3, 1986.[57]

The Pipeline Review Panel's report discussed the fundamental considerations in formulating policy transitions toward market-oriented pricing and advanced a schedule of timing for the changes that it recommended be made. The report recommended that pipeline tariffs, governmental policies and contract renegotiations be undertaken by November 1, 1986, to remove impediments to a market-oriented system.[58] The report compared the Canadian situation with that experienced in the United States and found that Canadian deregulation was "moving faster to a market-oriented pricing scheme" and that the lack of complete decontrol in the United States was "causing marketing difficulties for Canadian exporters and exposing Canadian pipelines and producers to increased risks."[59]

4. Surplus Procedures Review

Following the report of the Pipeline Review Panel, the NEB announced it had decided that its reserve to production (R/P) calculation procedure was no longer consistent with the new free market environment to which the *Western Accord* and subsequent policy changes had been intended to respond.[60] A new natural gas surplus determination policy was announced in July, 1987, after extensive hearings before the NEB in Ottawa, Calgary, and Toronto in April and May of 1987.[61] This became the fourth and final step in the decontrol of natural gas exports.

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55. *Id.*
56. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 3.
57. *Id.*
58. *Id.* at 28.
59. *Id.* at 23.
60. REASONS FOR DECISION, IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING, *supra* note 21 at 23.
61. REASONS FOR DECISION, IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 2.

After finding that "the current national energy policy framework is based on the premise that the marketplace determines the supply, demand, and price for natural gas," the NEB rejected an alternative proposal that used revisions to the R/P procedure as well as a return to the "Reserves Formula" and "Deliverability Procedure."[62] The NEB determined that the new market-based procedure was consistent with negotiated pricing and that allocating gas reserves under any formula approach would only interfere with market functioning.[63]

The NEB will continue to conduct oversight of market activity. Natural gas supply, demand and prices will be monitored and assessments will be made public in the *Canadian Energy Supply and Demand,* which was first published in 1986 and formed the basis for the export surplus reevaluation, and in *Natural Gas Market Assessments* that are issued on a more frequent basis.[64]

C. Spot Market Application Proceedings

Canadian producers faced the same dilemma as our domestic marketers in their attempt to participate in United States spot markets—the fastest growing segment of the industry. Because the lead time needed to gain approval for each transaction submitted under the original surplus determination procedures was about six months, it was nearly impossible for Canadian natural gas to compete effectively.

The NEB has now implemented a highly streamlined program utilizing self-implementing, blanket export licenses for spot sales with authorization periods which do not exceed two years.[65] Reporting under the blanket license is now on an after-the-fact basis and is usually done monthly for sales made in the preceding month.[66] Additionally, the NEB annually conducts performance reviews through its *Natural Gas Market Assessments* and *Canadian Energy Supply and Demand* reports to determine whether exporters are fully utilizing the capacity granted by the license. The 1985 restriction limiting short-term export volumes to 106 BCF has also been eliminated.[67] Additionally, the NEB announced that its policy would be to "turn around" short-term applications within seventy-two hours of their receipt.[68] If the contemplated export exceeds the limits of the self-implementing procedures, as is likely in the case of a long-term supply contract, a license must be secured through a combined export hearing and monitoring process now termed the "market-based procedure."[69]

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62. *Id.* at 6-7.
63. *Id.* at 9.
64. *Id.* at 26. The first *Natural Gas Market Assessment* after the change in the Surplus Procedures was issued in October, 1988.
65. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 4 (Sept. 1, 1988).
66. *Id.*
67. REASONS FOR DECISION, IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING, *supra* note 21 at 18-20.
68. *Id.* at 26.
69. REASONS FOR DECISION IN THE MATTER OF REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 1.

1. Application Content

An applicant for a short-term export license now must show the following:

1. The names of the exporter and importer;
2. the expected commencement date and duration of the export;
3. the selling price at the international border;
4. the export point; and
5. whether an executed sales agreement exists.[70]

If a contract does not exist, an executed copy of the sales agreements must be filed within thirty days of the NEB order.[71] The NEB will treat the price and related contractual matters as confidential for a period of ninety days from the issuance of an export order to protect the market position of the applicant.[72]

2. Pricing

In the past, the export price was compared to the sum of TransCanada Pipeline's Eastern Zone rate for contract demand service at a 100 percent of base load. Other pricing components included the Canadian ownership special charge, and the natural gas and gas liquids tax, less the federal subsidy of TransCanada Pipeline's transportation "tolls" (i.e., rates).[73]

As with previous Canadian export policy, price undoubtedly is the most important factor in obtaining NEB approval. The sophisticated pricing provisions being negotiated, however, make it difficult to establish the price at which gas actually will be sold under new or renegotiated contracts because the contract price often is a function of a variety of factors, most notably volumes, that cannot be predicted with certainty in advance.

The minimum border price now is established by comparing the proposed annual average price at the expected load factor with the equivalent load factor wholesale price paid by a Canadian distributor in the franchise area nearest the point of export.[74] The NEB now sees its role as "ascertaining whether Canadians can buy gas proposed for export on similar terms and conditions, including price, as can export customers."[75]

70. REGULATORY PROCEDURES AND INFORMATIONAL REQUIREMENTS FOR APPLICANTS FILING FOR CHANGES TO EXISTING NATURAL GAS EXPORT CONTRACTS AND LICENSES, *supra* note 36.

71. REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 8.

72. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 7 (Sept. 1, 1986).

73. REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 12.

74. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 9.

75. *Id.*

The change in calculating the minimum export price has two main implications. First, the use of nearby prices will reduce substantially the price for exports from adjacent areas of the two countries. Second, the use of the same load factor for comparison probably will result in the reverse effect, particularly where service is rendered pursuant to two-part (demand/commodity) rates. In the past, the expected export load factor usually was much less than 100 percent and, accordingly, the unit price for comparison purposes was greater. This methodology resulted in a greater per-unit rate for the export than if the 100 percent load factor rate was used. This, in turn, made it easier for a lower actual border price to be approved. If the expected load factor was exceeded, the result was lower per-unit prices. A second NEB price criterion had been that the price must result in prices in the United States market that are at least equal to the price of major competing energy sources.[76] This factor has been eliminated in the Surplus Redetermination Procedure.[77] The applicable area price can be determined by reference to the export points shown in Table 1.

The NEB has demonstrated its intention to enforce this criteria. In May 1986, the NEB issued cease and desist orders suspending further exports under short term orders by individual license holders when prices fell below those prevailing where the export took place.[78]

3. Volumes

In order to avoid problems with the operation of minimum bills under Federal Energy Regulatory Commission Order No. 380 and to ensure that contracted volumes will be taken, the NEB previously required short-term sales to include "contractual assurances" that "reasonable efforts" would be made to take gas offered by the seller.[79] This requirement has also been eliminated.[80]

For long-term orders, an ostensibly higher standard still applies: There must be "some form of assurance that the U.S. importer will take the quantities proposed to be exported."[81] This includes some provision to ensure the minimum revenue stream when contracts require the construction of new facilities, in order to provide an underpinning on which to finance such new facilities.[82]

Parties to short-term export contracts responded to the "contractual assurance" requirement in a variety of ways. Some short-term

76. *Id.*

77. REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 8.

78. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 6 (June 1, 1986).

79. AGREEMENT AMONG THE GOVERNMENTS OF CANADA, ALBERTA, BRITISH COLUMBIA AND SASKATCHEWAN ON NATURAL GAS MARKETS AND PRICES, *supra* note 53 at 8.

80. REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 4.

81. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING, AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 16-17.

82. *Id.*

Export Point

Huntington, B.C.
Kingsgate, B.C.
Aden, Alberta
Cardston, Alberta
Monchy, Saskatchewan
Emerson, Manitoba
Sprague, Manitoba
Fort Frances, Ontario
Niagara Falls, Ontario
Windsor, Ontario
Cornwall, Ontario
Phillipsburg, Quebec

Note: Price monitoring is largely conducted by provincial authorities based upon prices set by Removal Permit conditions and after-the-fact monitoring by the NEB.

Table 1. Area Price Comparisons for Canadian Exports

Source: National Energy Board, Ottawa, Ontario.

exports required the purchaser to buy all its requirements pursuant to the export contract; others were keyed to partial requirements.[83] Still others used stated volumes or simply required that "best efforts" be used on both sides.[84] A monthly nomination system also was used.[85] Actual exports as a percentage of authorized volumes has been between 50 percent and 60 percent.[86] Approximately 70 percent of volumes actually transported have moved under long-term licenses.[87]

On October 17, 1986, the NEB decided to consider extending initial export approvals made in 1983, which contained so-called "sunset clauses," as a condition of the license.[88] Unless extended or deleted from the approval by the NEB the license would expire at the end of its term. Furthermore, due to the build up of approved short-term exports on May 29, 1987, the NEB ruled that export authorizations will expire unless actual exports are made within six months of the date of approval.[89] Finally, there appears to be a shift from some short-term to long-term authorizations. Canadian gas supplies are being contracted for use in new United States co-generation facilities.[90]

D. Provincial Permits

In addition to NEB approval, parties seeking to export gas from Canada must secure a removal permit from the province in which the gas was produced.[91] The three major producing provinces have adopted different approaches.

Alberta will not issue provincial permits to end-users it considers more appropriately served by long-term contracts.[92]

Under Saskatchewan's permit procedures, prices paid for gas leaving the province must not be lower than those paid by provincial consumers for similar types of sales.[93] Furthermore, removal permits will not be issued for sales that displace Saskatchewan volumes that are currently under contract.[94]

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83. NATIONAL ENERGY BOARD, NEB ADOPTS NEW NATURAL GAS SURPLUS DETERMINATION PROCEDURE (Sept. 9, 1987).
84. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 10.
85. *Id.*
86. *Id.*
87. REASONS FOR DECISION IN THE MATTER OF: PHASE 1, THE SURPLUS DETERMINATION PROCEDURES PHASE OF THE GAS EXPORT OMNIBUS HEARING, *supra* note 21 at 22-23.
88. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 7 (March 1, 1987).
89. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 6 (June 1, 1987).
90. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 2-3 (March 1, 1989).
91. REASONS FOR DECISION IN THE MATTER OF: REVIEW OF NATURAL GAS SURPLUS DETERMINATION PROCEDURES, *supra* note 4 at 18.
92. *Id.*
93. *Id.* at 19.
94. *Id.*

Removal permit conditions in British Columbia require that prices charged for gas removed from the province not be lower than prices paid by British Columbia customers in the market area adjacent to the export point.[95] Contracts for gas removal must also have similar terms and conditions as those used in provincial service.[96]

E. *Timetable for NEB Approvals*

The NEB has set forth a schedule it hopes to keep in approving export applications. If the NEB adheres to the published schedule, it is possible that an NEB long-term license approval can be secured as soon as six weeks.[97] Governor-in-Council approval may take another two weeks.[98] Short-term export orders can now be secured in three working days if the application is complete at the time of filing.[99]

VI. THE FREE TRADE AGREEMENT

The previous discussion has demonstrated that, through deregulation, relatively free trade in natural gas has existed since 1984.[100] Prior to the adoption of the FTA, both the United States and Canada had become each others' largest trading partner.[101] Moreover, this level of commerce is the world's largest bilateral trade relationship.[102] Both Canadians and Americans saw the adoption of the Free Trade Agreement as a formalization of the status quo.[103] In its summary of the FTA, the Office of the United States Trade Representative did not discuss the energy provisions of the agreement.[104] Nevertheless, natural gas trade was the subject of extensive discussion in the energy review group.[105] Although there were no immediate or dramatic impacts on natural gas trade, regulatory stability under the FTA should help eliminate uncertainty from the market place and makes this subject one for further evaluation.

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95. *Id.*
96. *Id.*
97. Telephone interview with Dennis Dubuc, Chief, Gas Policy Application, Gas & Oil Division, National Energy Board (April 24, 1989).
98. *Id.*
99. *Id.*
100. MINISTRY OF ENERGY, MINES AND RESOURCES, THE CANADA-U.S. FREE TRADE AGREEMENT AND ENERGY (1987); Buckley & Grammer, *Gas Trade With Canada: Breaking Down Barriers at the Border,* 2 NAT. GAS. LAW J. 24, 36-37 (1988).
101. OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE, EXECUTIVE OFFICE OF THE PRESIDENT, BACKGROUND ON U.S.-CANADA ECONOMIC RELATIONSHIP (Oct. 4, 1987). Trade with Canada represents 24 percent of U.S. exports and 18 percent of total imports. Trade with the United States accounts for 70 percent of Canadian imports and 78 percent of exports. *Id.* at 3.
102. Interview with R.A. Reinstein, Director, Energy and Natural Resources, Office of the United States Trade Representative, in Washington, D.C. (Oct. 22, 1987).
103. *Id.*
104. OFFICE OF THE UNITED STATES TRADE REPRESENTATIVE, EXECUTIVE OFFICE OF THE PRESIDENT, SUMMARY OF THE TRADE AGREEMENT (Oct. 4, 1987).
105. Interview with Andrea K. Waldman, International Economist, Office of International Affairs, United States Deptartment of Energy, in Washington, D.C. (Oct. 21, 1987).

Basically, a free trade area is a combination of two or more countries in which tariffs, non-tariff restrictions, and other trade distortions are eliminated for most trade sectors. Prior to negotiations with Canada, the United States had established a free trade area only with Israel.[106]

A. Negotiation Authority

Section 102 of the Trade Act of 1974 authorizes the President to negotiate agreements on bilateral trade areas and to have them considered by the Congress on a "fast track" basis.[107] That authority was scheduled to expire on midnight, January 2, 1980, but was extended for another eight years by the Trade Agreements Act of 1979.[108]

In order for an agreement to be eligible for fast track consideration, two key conditions must be met: (1) The negotiations must be requested by the foreign country; and (2) the President must provide advance notice to the House Ways and Means Committee and the Senate Finance Committee.[109]

Interested parties in the private sector participate in developing U.S. negotiating objectives through Trade Policy Committees and lower level review groups. The committees include representatives from industry, agriculture, labor, consumers, and the general public.[110] These committees report to the President through the Office of the United States Trade Representative and the Departments of Agriculture, Commerce, and Labor.[111]

1. Fast Track Procedures

Once negotiations are underway, several other steps must be taken if the agreement is to be considered under fast track procedures. First, the President is required to consult with Congress. Second, the President must notify Congress of the Administration's intention to enter an agreement ninety days before doing so. Third, after entering an agreement, the President must submit the agreement to Congress, together with a draft of the implementing bill, a statement of any administrative action needed to implement the agreement, an explanation of how the bill or agreement changes or affects existing law, and a statement of reasons why the agreement serves the interests of United States commerce.[112] Collectively, these documents are referred to as the "FTA package."

106. The United States-Israel Free Trade Area Implementation Act of 1985, Pub. L. No. 99-47, 99 Stat. 82 (1985).

107. 19 U.S.C. § 2112(a) (1988). The FTA package includes the agreement signed by the heads-of-state as well as policy justification, implementing legislation and regulatory changes. *Id.*

108. Pub. L. No. 96-39, 93 Stat. 144 (1979).

109. 19 U.S.C. § 2112(c) (1988).

110. 15 C.F.R. § 2002.0 (1988).

111. *Id.*

112. 19 U.S.C. § 2112 (1988).

The implementing bill is introduced in both houses of Congress and referred to the jurisdictional committees on the same day.[113] The principal committees with jurisdiction are the House Ways and Means and the Senate Finance Committees. The bill also could be referred to the Energy, Agriculture, Commerce, Foreign Affairs, and Banking Committees.[114] The committees have forty-five legislative days in which to report the bill after which they are discharged automatically from further consideration.[115]

Each House votes on the bill within fifteen legislative days after the measure has been received from the standing committees.[116] Amendments are not in order.[117] A simple majority of each House is required for acceptance.[118]

2. Chronology of Negotiations

In March of 1985, at the so-called "Shamrock Summit," President Ronald Reagan and Prime Minister Brian Mulroney asked their trade officials to explore ways to reduce or eliminate existing barriers to trade between the United States and Canada.[119] The two heads-of-state formally requested that the United States and Canada explore the potential for negotiating a comprehensive free trade agreement on September 26, 1985.[120] The Canadian Prime Minister announced his intention to conduct negotiations for "the broadest possible package of mutually beneficial reductions in tariff and non-tariff barriers between the two countries."[121]

President Reagan formally notified the Senate Finance and the House Ways and Means Committees on December 10, 1985, of his intent to enter bilateral negotiations with Canada using fast track provisions.[122] On April 23, 1986, the Senate Finance Committee narrowly granted fast track authority for the trade negotiations when a resolution to deny the authority failed on a ten to ten vote.[123]

United States and Canadian negotiators met for the first time on May 21, 1986, in Ottawa.[124] Subsequently, President Reagan and Prime Minister Mulroney reiterated their commitment to the trade talks during their meeting in Canada in April of 1987.[125] They agreed that a free trade arrangement between the countries would be an opportu-

113. *Id.*
114. *Id.*
115. *Id.*
116. *Id.*
117. *Id.*
118. *Id.*
119. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 20.
120. BACKGROUND ON U.S.-CANADA ECONOMIC RELATIONSHIP, *supra* note 101.
121. *Id.*
122. *Id.*
123. *Id.*
124. *Id.*
125. *Id.*

nity to provide benefits for American and Canadian consumers and businesses.[126]

President Reagan and Prime Minister Mulroney signed the FTA on January 2, 1988, and submitted the FTA package to their respective legislative bodies for adoption.[127] In a public statement, after signing the FTA, the President included improved "security through additional access to Canadian energy supplies" as among the benefits of the FTA.[128] The House of Representatives initially approved the FTA legislation on a 366 to 40 vote before its August recess.[129] Final adoption was achieved when the measure passed the United States Senate on September 19, 1988, on an 83 to 9 vote.[130] The Canadian Parliament adopted implementing legislation on December 30, 1988.[131] After adoption by both governments, the FTA became effective on January 1, 1989.[132]

3. FTA's Energy Provisions

Free and open energy trade is a significant component of the FTA because it serves as a framework to enhance the energy security and increase the industrial competitiveness of both countries.[133] The main goal for bilateral trade in "energy goods" was nondiscriminatory access for the United States to Canadian energy supplies and secure market access for Canadian energy exports to the United States.[134] One negotiator in the Energy Review Group sees the FTA as creating "a more stable environment in which market forces can work."[135] Both sides have agreed to prohibit restrictions on imports or exports, including quantitative restrictions, taxes, minimum import or export price requirements, or any other equivalent measure, subject to very limited exceptions.[136]

More specifically, the FTA prohibits either country from imposing trade restrictions on energy export commodities (coal, electricity, crude oil and natural gas) except for limited circumstances involving national security or health and welfare reasons.[137] Even under such conditions, restrictions can be imposed only if:

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126. *Id.*
127. *Id.*
128. Statement by the President, Office of the Press Secretary (Jan. 2, 1988).
129. 5 Int'l Trade Rep. (BNA), 1118 (Aug. 10, 1988).
130. 5 Int'l Trade Rep. (BNA), 1264 (Sept. 21, 1988).
131. NATIONAL ENERGY BOARD, REGULATORY AGENDA at 9 (March 1, 1989).
132. United States-Canada Free-Trade Agreement Implementation Act of 1988, Pub. L. No. 100-449, 102 Stat. 1851 (1988).
133. Interview with R.A Reinstein, *supra* note 102.
134. *Id.*
135. Interview with T. D. McGee, Counselor (Energy) Canadian Embassy, Washington, D.C., Free Trade and Energy Price, Toronto, Ontario (Oct. 22, 1987).
136. Free-Trade Agreement, Jan. 2, 1988, United States-Canada, ch. 9, *reprinted in* COMMUNICATION FROM THE PRESIDENT OF THE UNITED STATES, H.R. Doc. No. 100-216, 100th Cong., 2d Sess. 297 (1988).
137. *Id.*

1. The restrictions do not reduce the proportion of total exports of that commodity relative to the exporting country's supply of that commodity as measured by the previous three years or other representative period;

2. the exporting country does not impose a higher export price, including duties, fees, licenses, border prices, etc.; and

3. the restriction does not disrupt the normal channels of supply or normal proportions among specific commodities.[138]

The United States and Canada have also agreed to consult on energy regulatory actions that would directly result in discrimination inconsistent with the principles of the FTA.[139] This provision of the FTA is particularly important to the Canadians. The entire discussion on natural gas in the Canadian government's briefing paper on the energy provisions of the FTA states:

> The right of consultation, if the United States takes regulatory action which discriminates against Canadian suppliers, may be helpful in assuming that FERC decisions do not unfairly penalize natural gas imports from Canada.[140]

Canada's current Minister of Energy, Mines, and Natural Resources, the Honorable Marcel Masse, characterized the perception of prior bilateral trade relations as reflecting "the belief that a trade-off existed between promoting economic growth through exports and enhanced Canadian security of supply."[141] For the Canadians the FTA was intended as a formal recognition that the dichotomy between trade and energy reserves has been eliminated, and that economic growth and energy security can be pursued as complementary policy objectives.[142] Market-oriented policies function more effectively in an atmosphere of institutional stability and the FTA serves as a framework for predictability of governmental response.[143]

The Canadians do not view the FTA as creating a continental energy policy. No matter how market-oriented the FTA is, the Canadians maintain they have reserved their prerogative to impose restrictions should such measures be necessary to achieve their national energy policy goals.[144] Masse also points out that market access does not equate to an obligation to deliver.[145]

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138. *Id.*, art. 904.
139. *Id.*, art. 905.
140. THE CANADA-U.S. FREE TRADE AGREEMENT AND ENERGY, *supra* note 100 at 2.
141. Honorable Marcel Masse, Minister of Energy, Mines and Natural Resources, Third Annual Joint Conference Canada/U.S. Trade in Energy, Quebec, A.B.A. & C.B.A. (1988).
142. *Id.*
143. *Id.*
144. *Id.*
145. *Id.*

Moreover, to the Canadians, the energy provisions of the FTA are generally seen as formalizing a deregulated trading atmosphere that had developed by 1984 through regulatory and policy changes on both sides of the border.[146] Due to excess deliverability (oversupply) and the drop in crude oil prices, the Canadians do not expect the FTA to expand natural gas exports.[147] Rather, the FTA is viewed as helping to ensure that gas imports from Canada are not unfairly treated by United States regulatory bodies.

Despite a major role in several regional U.S. markets, Canadians insist they do not intend to become a dependent source of supply by reducing their prices through FTA procedures.[148] With respect to existing measures, Canada has agreed to eliminate several practices that discriminate against energy exports to the United States. Correspondingly, the United States has agreed to eliminate various import restrictions and to allow Canada access to oil from Alaska's North Slope, subject to certain conditions.[149] The formalization of business-as-usual natural gas trade comes into clearest perspective in reviewing the FTA's implementing legislation. FTA energy provisions addressing changes in existing legislation and regulation are completely silent in the area of natural gas.[150] As discussed in the following section, the lack of specific legislative direction has resulted in various proceedings seeking judicial interpretation.

VII. LEVELING THE PLAYING FIELD

The process of deregulating natural gas on both sides of the United States-Canada border still has not produced the "level playing field" that has been the oft stated objective of regulators and industry.[151] Nevertheless, the independent actions discussed in earlier chapters occurring simultaneously have served to bring sharply into focus those issues looming on the regulatory landscape that pose obstacles to a more efficient cross-national market in natural gas trade.

Also, the acceptance of the FTA encourages more ambitious proposals, such as those advanced by Commissioner Phillip O'Connor of the Illinois Commerce Commission, for a North American energy consortium or common market.[152] As institutional barriers are removed, market functions will result in the price of Canadian natural gas to

146. THE CANADA-U.S. FREE TRADE AGREEMENT AND ENERGY, *supra* note 100 at 3.
147. *Id.* at 2.
148. *Id.*
149. Free-Trade Agreement, *supra* note 136, ch. 9.
150. United States-Canada Free Trade Agreement Implementation Act of 1988, *supra* note 132 at § 305. Specific changes in the Energy section of the FTA implementation act addressed Alaskan oil to be used in refineries in Vancouver, B.C. and the use of Canadian produced uranium in the U.S. nuclear program. *Id.*
151. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 33. A "level playing field" means similar regulatory treatment of participants similarly situated in the natural gas market. *Id.*
152. P. O'Connor, Chairman, Illinois Commerce Commission, as cited in INSIDE FERC (Feb. 11, 1985).

end users on both sides of the border ultimately determining both the levels of gas exports to the United States and domestic prices and production rates.

A. Agenda for the Future

The major regulatory issues that continue to have an impact upon, if not distort, Canadian exports to the United States include the following:

1. FERC Opinion No. 256, restricting "as billed" charges;

2. FERC Order No. 380, which tends to restrict the recovery of construction costs for pipeline systems oriented for export;

3. transportation system access under FERC Order No. 500 as it supercedes Order No. 436;

4. FERC determinations on rate design; and

5. demands by domestic natural gas producers that the FTA be used to redress disparities between United States and Canadian suppliers.

It is interesting that most of these major issues are products of action by the FERC. Although the FERC has little direct control over authorized imports, once Canadian natural gas enters the United States, it is subject to the same market controls that govern domestic production.[153]

1. Opinion No. 256

As mentioned in Part II, the ERA has primary responsibility for reviewing and authorizing all import arrangements. The FERC has responsibility for reviewing the construction and operation of facilities, and the terms and conditions applicable to any subsequent sales for resale and/or transportation of the imported gas in the United States. The Delegation Orders require the FERC to act in a manner consistent with determinations made by the ERA and the policy considerations reflected in any authorization. These roles often overlap, and inconsistencies occur with some frequency.

One example involves FERC Opinion No. 256.[154] In this December 1986 proceeding, the FERC addressed the so-called "as billed" issue. The central question was whether U.S. interstate pipelines should be allowed to automatically recover demand charges associated with purchases of Canadian imports through their tariffs.[155] While this appears to be strictly a sale for resale rate question, within the exclusive purview of the FERC, the decision created friction with the ERA's import policy.

153. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 43-44.

154. Natural Gas Pipeline of Am., 37 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,215 (Dec. 8, 1986), *reh'g denied* 39 F.E.R.C. ¶ 61,218 (May 27, 1987) (The pipeline had recently renegotiated a two-part tariff in its Canadian purchase contract and had filed to reflect demand and commodity charges on an "as-billed" basis in its rates).

155. *Id.* at 61,543.

Under FERC Opinions Nos. 256 and 256-A, pipelines that purchase gas from other pipelines are allowed to pass through the charges in the form imposed by the seller.[156] In other words, the seller's commodity and demand charges can be recovered automatically through corresponding charges in the purchaser's resale rates. If the upstream supplier is a producer, however, the regulations require recovery of all charges through the commodity component of the purchaser's resale rates.[157] Opinion No. 256 involved two kinds of sales: (1) A direct sale from a Canadian producer to Natural Gas Pipeline Company of American; and (2) a sale by TransCanada Pipelines Ltd. to Great Lakes Gas Transmission Company for resale to Natural.[158] Natural asked the FERC for authorization to flow the costs associated with both sales through to its resale customers on an as-billed basis.[159]

The FERC initially determined that it had the requisite jurisdiction to address the as-billed issue, even though the ERA had already approved the contracts that contained the two-part rates at issue.[160] In its approval, ERA stated in pertinent part, that it "endorses in principle the pass through of the two-part structure of the arrangement, but not necessarily the pass through of every single cost element exactly as proposed."[161] Normally, one would assume that FERC's as-billed regulations cannot apply to Natural's purchases from Canadian suppliers because the FERC does not examine the rates of Canadian pipelines and producers. Nevertheless, FERC's "as-billed" regulations were applied to Natural's purchases from Canadian suppliers even though FERC does not directly examine the rates of Canadian pipelines and producers. As a way of ensuring that Canadian contract prices satisfy the "just and reasonable" standards of the Natural Gas Act of 1938 (NGA), FERC required Natural to modify its demand charge to exclude Canadian production, gathering and take-or-pay costs as well as all fixed costs associated with return on equity and related taxes from its demand charge.[162] To ensure its decision would not conflict with the ERA's policy that domestic and imported gas should be treated equally, the FERC also examined the reasonableness of the demand charges. Shortly after the issuance of Opinion No. 256, FERC attempted to clarify the scope of its jurisdiction not to intrude into those areas under ERA's oversight involving international trade, foreign policy, national secu-

156. *Id.* Producer rate changes shall be applied to the commodity component of the existing rates of a pipeline's two-part rates and to the volumetric rates of a pipeline company's one-part rates. Pipeline supplier rate charges shall be applied "as-billed" to a pipeline company's two-part rates and shall be applied to a pipeline company's volumetric rates in a manner which maintains the pipeline company's existing one-part rate design. 18 C.F.R. § 154.38(d) (1988).

157. Natural Gas Pipeline of Am., 37 Fed. Energy Reg. Comm'n Rep. at 61,544-46.

158. *Id.* at 61,537.

159. *Id.*

160. *Id.* at 61,536.

161. *Id.*

162. *Id.* at 61,545-46. FERC specifically rejected its staff's recommendation that all Canadian gas costs be flowed through as volumetric costs. *Id.* at 61,544.

rity and balance of trade payments.[163] Opinion No. 256 effectively means that the typically higher commodity charge under long-term import contracts must now be recovered through higher sales volumes and that incremental sales of natural gas will not be able to be as attractively priced as would have been the case with an "as billed" pass through. The loss of this pricing incentive deeply concerned the Canadian government and its producers.[164] Retaliatory "dumping" of low cost Canadian gas was threatened.[165]

If Opinion No. 256 is not modified in later FERC rulings, it will likely trigger a round of contract renegotiations or litigation between Canadian producers and their U.S. pipeline customers. Renegotiations may be voluntary or may be required under contract provisions concerning the effects of certain regulatory actions. The parties probably will strive to shift costs from demand components and thereby raise commodity components of two-part price structures. Since any increase in commodity charges will lessen a pipeline's propensity to purchase incremental volumes, take-or-pay and related provisions may also require amendments. Finally, contracts with "regulatory out" clauses may be subject to termination, depending upon the specific language of the particular provision.

2. Order No. 380

FERC's rate policies must be considered as a crucial factor by Canadian pipelines and producers when entering into an export sales contract with U.S. interstate pipeline companies. Under FERC Order No. 380, pipelines are not allowed to charge customers for the cost of gas that the customer refuses to take, thereby depriving the pipeline of its equivalent of take-or-pay protection.[166] This in turn forces pipelines to minimize their own exposure to take-or-pay, whether the pipeline is contracting for domestic or imported gas supplies.

As discussed in Part III, some pipelines that purchase Canadian supplies under long-term contracts have renegotiated their contracts to include two-part price structures. These structures are composed of a demand and a commodity charge, and have been subject to a number of criticisms before the FERC. These criticisms are examined in more detail later in this chapter.

Another FERC rate policy affecting imports has evolved from a rate case involving Columbia Gas Transmission Corporation.[167] In that case,

163. Northern Border Pipeline Co., 39 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,104 at 61,355 (April 30, 1987) *reh'g denied,* 41 F.E.R.C. (CCH) ¶ 61,275 (Dec. 4, 1987).

164. U.S. CANADA GAS TRADE REVIEW, *supra* note 1 at 1. The strong response of the Canadian government was demonstrated by an exchange of letters between Canadian Prime Minister Brian Mulrooney and President Ronald Reagan. *Id.*

165. Interview with Andrea K. Waldman, *supra* note 105.

166. 18 C.F.R. § 154.111 (1989). Order 380 was issued on May 25, 1984 and required the elimination of minimum commodity bills from interstate pipeline tariffs. As a result, pipelines could no longer charge their local distribution company customers for contract levels which were not actually taken. *Id.*

167. Columbia Gas Transmission Corp. v. Fed. Energy Regulatory Comm'n, 831 F.2d 1135 (D.C. Cir. 1987).

the FERC adopted new standards to determine if a particular pipeline has been "imprudent" or "abusive" in its gas purchasing practices. If either is found, the pipeline can be penalized in a number of ways, including denying the pass through of full gas purchase costs to customers. The FERC had permitted pipeline companies to directly bill their customers for deferred production-related costs because this approach "will equitably bill customers for the higher amounts they should have paid based on actual purchases during past billing periods."[168] The D.C. Court of Appeals ruled that the direct billing approach was in effect retroactive rate making and beyond the FERC's scope of authority.[169]

The Order No. 380 series of rulings prohibited the so-called "minimum bill" in which domestic and imported gas contracts stated take-or-pay levels in terms of volume-related minimum obligations. Correspondingly, when considered against the NEB's desire to ensure that volumes committed to export were actually taken, a potential conflict was created by import contracts with high take-or-pay provisions.

In an attempt to avoid running afoul of Order No. 380, one importer adopted a "settlement payment" tier for a specified amount per MMBTU for volumes below a set take-or-pay level but above the minimum or actual annual volume.[170] This approach has been accepted by the FERC.[171] After lobbying by Canadian industry and government representatives, FERC issued an amendment to its order, which exempted the pre-built sections of Alaska Natural Gas Transportation System (ANGTS) in southern Canada from Order No. 380.[172] The overall value of this ruling is dubious because it involves the ANGTS, which was specifically excepted from Order No. 380 by Order No. 380-A.

Furthermore, the D.C. Court of Appeals has ruled that even though the provisions of Order No. 380 may burden an export agreement approved by ERA, it does not exceed FERC's jurisdiction to apply the minimum bill requirements to such agreements.[173] The issue before the Court of Appeals in that case was based on the claim that Order No. 380 was contrary to ERA approval of take-or-pay provisions in an export

168. *Id.* at 1140 (quoting Brief for Commission at 13 (quoting Transcontinental Gas Pipeline Corp., 33 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,213 at 61,443 (1985))).

169. *Columbia Gas,* 831 F.2d at 1137.

170. Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Commodity Bill Provisions, 27 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,318 (May 25, 1984), *reh'g denied,* 28 F.E.R.C. (CCH) ¶ 61,175 (July 30, 1984), *reh'g denied,* 29 F.E.R.C. (CCH) ¶ 61,077 (Oct. 24, 1984), *aff'd sub nom.* Wisconsin Gas Co. v. Fed. Energy Regulatory Comm'n, 770 F.2d 1144 (D.C.Cir. 1985), *cert. denied* Trunkline Gas Co. v. Fed. Energy Regulatory Comm'n, 476 U.S. 1114 (1986).

171. Northwest Pipeline Corp., 23 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 63,079, *aff'd* 27 F.E.R.C. (CCH) ¶ 61,012 (1984).

172. Elimination of Variable Costs from Certain Natural Gas Pipeline Minimum Comodity Bill Provisions, Order Denying Rehearing and Granting in Part Applications for Stay, 49 Fed. Reg. 31,259 (1984).

173. Wisconsin Gas Co. v. Fed. Energy Regulatory Comm'n, 770 F.2d 1144 (D.C.Cir. 1985), *cert. denied* Trunkline Gas. Co. v. Fed. Energy Regulatory Com'n, 476 U.S. 1114 (1986).

agreement. The Court ruled that even though the pipeline's minimum bill was eliminated from its tariff, the Order did not alter the conditions of the underlying contract and that any impact on ERA jurisdiction was "trivial."[174]

FERC subsequently faced the question of restricting cost recovery provisions agreed to in Canadian export agreements under Order No. 380 in tariff filings by Natural Gas Pipeline of America.[175] Despite prior approval of the contract's allocation of Canadian pipeline charges to the United States pipeline as demand charges by both the ERA and FERC's administrative law judge, the Commission removed some charges from the demand component of the tariff and required that they be reflected as commodity charges. In its decision, FERC noted that:

> The essence of the as-billed principle is that the 'upstream pipeline's demand charges are included in the downstream pipeline's demand charges and the upstream pipeline's commodity charges are included in the downstream pipeline's commodity charges.'[176]

Although FERC seems willing enough to engage in restructuring rates of ERA approved contracts, it has more recently stated that it will not intrude in areas involving international trade and foreign policy over which ERA has jurisdiction.[177]

Recently, one major interstate pipeline has sought judicial relief from its long-term import contract due, in part, to the effects of Order No. 380. In its complaint for declaratory relief based upon the contract doctrines of force majeure, impossibility of performance and commercial frustration, Northwest Pipeline alleged that:

> The issuance and implementation of Orders Nos. 380, 436 and 500 and certain related regulatory directives has deprived Northwest of its historical merchant function by regulatory fiat and relegated it to the role of a transporter for gas sold by others and a supplier only of last resort.[178]

While this case has been settled, it is a clear example of how FERC policies that are primarily directed at domestic natural gas sales impact upon import arrangements that have previously been approved by the NEB and the ERA.

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174. *Wisconsin Gas,* 770 F.2d at 1156.

175. Natural Gas Pipeline of America, 37 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,215 (Dec. 8, 1986), *reh'g denied,* 39 F.E.R.C. (CCH) ¶ 61,218 (May 27, 1987).

176. *Id.* at 61,861.

177. Northern Border Pipeline Co., 39 Fed. Energy Reg. Comm'n Rep. (CCH) at 61,355.

178. Northwest Pipeline Corp. v. Westcoast Energy, Inc., C88-1262 (filed Oct. 3, 1988, U.S.D.C. W.D. Washington). This case was settled on a basis of payment of $10,413,718.56 by the pipeline to its Canadian supplier. As a result of NEB approval of this settlement, Northwest was released from its service agreement and Westcoast has become a "Canadian open access" pipeline transporting natural gas on behalf of the British Columbia Producers Cooperative (BCPC) to Kingsgate for delivery into Northwest's system for transportation as spot-market natural gas.

3. Order No. 500

The premier issue for the natural gas industry has been FERC's effort to open up access to interstate natural gas pipelines for the transportation on behalf of other parties of gas not owned by the pipeline company. Open access transportation is of concern to imported natural gas as well.

Open access transportation was originally adopted as part of FERC Order No. 436. However, in *Maryland People's Counsel v. Federal Energy Regulatory Commission*, the circuit court remanded the proposal to FERC for further consideration.[179] It was reissued on August 14, 1987, as Order No. 500.[180] Open access is of particular concern for imported natural gas because under the Original Order No. 436 none of the United States pipeline companies that interconnected at the U.S.-Canada border had applied for a 436 certificate. One month after Order No. 500 was issued by FERC, the D.C. Circuit Court entered an order making it effective immediately.[181] As modified by Order No. 500, nineteen of forty interstate pipelines capable of open access transportation for imported natural gas have accepted such blanket certificates.[182]

As discussed in Part II, the major long-run limitation on natural gas imports is the transportation capacity of United States pipelines. Voluntary open access to this already limited transportation network is vital. Fortunately, a number of pipelines that would be used for transporting direct purchases of Canadian gas either have accepted Order No. 500 certificates or already have appropriate transportation rates under Section 311 of the NGPA in place, thus eliminating a major source of potential controversy in contested case proceedings before the FERC under Section 7 of the NGA.[183]

4. Rate Design

The Canadian approach to market-responsive pricing has chiefly employed a straight fixed-variable pricing structure where gas supplies with a different rate structure were offered to United States customers. This rate structure includes a two-part division of fixed and variable demand and commodity costs approved by the NEB for use in Canada. This type of rate structure has not been approved for use in the United States for several decades.

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179. 761 F.2d 780 (D.C.Cir. 1985).

180. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Interim Rule and Statement of Policy, 52 Fed Reg. 30,334 (Fed. Energy Regulatory Comm'n 1987).

181. Associated Gas Distributors v. Fed. Energy Regulatory Comm'n, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied,* Interstate Natural Gas Assoc. of Am. v. Fed. Energy Regulatory Comm'n, 108 S.Ct. 1468 (1988).

182. CAMBRIDGE ENERGY RESEARCH ASSOCIATES, NATURAL GAS TRENDS, 1988-89 EDITION 82 (1988).

183. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 37-39.

Under the straight fixed-variable two-part rate, pipeline costs deemed to be fixed are allocated among the various classes of customers and assigned to the demand charge that the customer pays regardless of the volume of purchases. All other costs become variable costs, assigned to a commodity charge, and recovered as a volumetric charge per unit of gas purchased.[184]

As a general proposition, natural gas can more easily compete with fuel oil if the commodity charge is relatively low. However, the approach that FERC has pursued has proven to be at cross purposes with this approach because since the 1950s, it has favored assigning a portion of fixed costs to the commodity charge. This approach encouraged pipeline efficiency in investment and operations by shifting some of the risk from the customer to the pipeline company.

As oil prices began to fall, FERC in 1984, modified the fixed-variable rate structure on an individual basis, by assigning all fixed costs (except taxes) to the demand charge, return on equity and all producer costs (about 20 to 25 percent of total fixed costs).[185] Keeping gas production charges, including take-or-pay charges in the commodity cost, places the economic risk on the pipeline shareholders if the system does not market sufficient volumes to recover all fixed costs. This is an attempt to allow market forces to have the greatest possible effect within the existing regulatory framework. However, the burdensome levels of take-or-pay commitments on many pipeline systems overwhelmed this change in rate design. After it became clear that the resolution of this issue was a critical factor in pipelines being willing to accept open access certificates under Order Nos. 436 and 500, FERC permitted the pass-through of 25 to 50 percent of take-or-pay payments as demand charges.[186]

Some form of rate regulation remains unavoidable for transportation, however, in order to deal with the natural monopoly characteristics of interstate pipelines. So-called "postage stamp" transportation rates that assign one price or rate to natural gas transported over any distance have been a sensitive issue with Canadian and United States producers. Both factions have argued that such rates are discriminatory to gas that travels only a short distance to its ultimate market.[187] The alternative approach is to use mileage based rates as FERC originally proposed in Order No. 436.[188] So far, the low incidental cost of moving natural gas in combination with the complex nature of FERC reporting and cost accounting has not provided the necessary incen-

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184. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 78-79.

185. Natural Gas Pipe Line Company, 25 Fed. Energy Reg. Comm'n Rep. (CCH) ¶ 61,478 (Nov. 4, 1983).

186. 18 C.F.R. §§ 2, 284 (1989).

187. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 38.

188. Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Final Rule and Statement of Policy, 50 Fed. Reg. 42,408, 42,410 (1985).

tive to move away from postage stamp rates. The Canadian government claimed that such charges were biased against "northern tier suppliers" after FERC approved postage stamp transportation rates on systems operated by Natural Gas Pipe Line Company of America and Northern Natural Gas Company.[189] Yet another variation has been the use of area or zone rates for assessing transportation charges. This approach has met with skepticism because the zones can be arbitrarily drawn in apparent attempts to protect key pipeline market areas.[190]

On May 30, 1989, the FERC issued a policy statement which showed that the commission is prepared to apply a new standard of economic efficiency to pipeline transportation rates in order to determine whether such charges would be just and reasonable.[191] Enforcement of the policy will be left to the participants in the rate case and the administrative law judges presiding over them.[192] The FERC requires the resolution of six major issues for those pipelines which had been operating as open access systems.[193]

In particular this statement reflects a movement away from the modified-fixed-variable rates and will result in the elimination of the demand charge for recovering fixed costs based on annual usage of pipeline capacity. The statement was issued principally in response to demands by gas producers and other non-local distribution companies who have been shipping on interstate pipelines. The rate design policy has been referred to as a measure for the enforcement of Order No. 436 and Order No. 500.[194] It is interesting to note that the D.C. Circuit Court expressly left open for "another day and another proceeding" the issue of how economic efficiency will be determined.[195]

B. Producer Complaints

U.S. producers have been concerned that a flood of Canadian gas will come across the border and undercut opportunity for market growth from them.[196] The initial perception of this threat appears to have begun

189. Telephone interview with Constance L. Buckley, Director, Natural Gas Division, Office of Fuels Programs, Office of Fossil Energy (March 11, 1989).

190. *Id.*

191. Policy Statement Providing Guidance with Respect to the Designing of Rates, 54 Fed. Reg. 24,382 (1989).

192. *Id.* at 24,382.

193. *Id.* at 24,384-87. The issues to be evaluated in the rate case include:
(1) Annual versus Seasonal Rates.
(2) Demand and Commodity Charges.
(3) Capacity Adjustments.
(4) Discounting and Maximum Interruptible Rates.
(5) Transportation Rates.
(6) Separation of Transportation, Storage and Gathering Services. *Id.*

194. Moring, *Pipeline Rate - Design, Policy Involves Problems for LDC's,* 6 NAT. GAS 11 (August 1989).

195. Associated Gas Distributors v. Fed. Energy Regulatory Comm'n, 824 F.2d 981 at 1012 (D.C.Cir. 1987).

196. *U.S. Gas Producers Fear Market Losses to Canada with Trade Pact,* OIL & GAS J. 17 (April 4, 1988).

with the *Western Accord*.[197] The *Western Accord* foreshadowed policy changes that resulted in a growing availability of natural gas in Canada. Consequently, a growing Canadian surplus might allow Canada to drop its "least cost alternative" test for competing fuels criteria in order to move additional volumes, which would place even greater pressure on U.S. gas prices. Indeed, under the FTA, Canada is obligated to eliminate these criteria.[198]

It is not surprising that natural gas importation was the focus of the substantial controversy in negotiating the energy provisions in the FTA.[199] For instance, the twenty-nine states that are signatories to the Interstate Oil Compact Commission presented a resolution opposing the approval and implementation of the FTA because of "current U.S. and Canadian regulatory practices, which give Canadian natural gas preferential treatment in U.S. markets."[200] United States producers have made several specific arguments to support their claims, which are examined in the next sections of this chapter.

1. Two-Part Border Price Distortion

Pipeline sales of natural gas to an end user or local distribution companies (LDC) are priced according to a two-part rate.[201] The demand component is based on the size of the service obligation under the contract. The commodity rate is based upon the actual deliveries of natural gas to the purchaser. Such two-tiered pricing is used because end users or LDCs can readily shift between alternative suppliers.[202] As a general rule, pipelines are under pressure to keep their commodity rates low, but they do not face the same pressure regarding demand charges.[203]

Canadian natural gas suppliers may have achieved an advantage in the United States market because they have settled high pre-existing take-and-pay obligations for a favorable division between demand and commodity components, which shifts commodity costs into their demand charges.[204] United States producers claim that this allows Canadian gas (which is assumed to be more expensive on a total unit costs basis) to compete favorably with domestic gas when costs are required by FERC rules to be recovered in pipeline commodity rates.[205] As discussed earlier in this chapter, FERC's "as billed" decision, Opinion No. 256, limited demand charge treatment of Canadian gas to those costs that

197. LeMay, *White Paper on Canada Gas Dumping (Canadian Gas Issue) and Pipe Shortages for Drilling Wells,* NEW MEXICO DEPT. OF ENERGY AND NATURAL RESOURCES, OIL CONSERVATION DIVISION (Oct. 3, 1987).
198. *See,* Free-Trade Agreement, *supra* note 136, ch. 9, annex 905.2.
199. Interview with R.A. Reinstein, *supra* note 102.
200. INTERSTATE OIL COMPACT COMMISSION, RESOLUTION ON U.S.-CANADA FREE TRADE AGREEMENT (undated).
201. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 40.
202. *Id.*
203. *Id.*
204. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, INDEPENDENT PETROLEUM ASS'N. OF AMERICA, 1 (Dec. 7, 1987).
205. *Id.*

would be allowed demand charge treatment by downstream domestic pipelines. The application of this rule is said not to have a uniform impact in all regional natural gas markets.[206] This is because the ERA has not applied FERC Order No. 256 principles to the border prices it regulates. For example, in the case of California and Minnesota, Canadian natural gas imports are regulated by the ERA. Because the gas is not delivered to distribution companies there are no subsequent "first sales" which are subject to FERC rate regulation.[207] United States producers selling into these markets may be at some disadvantage. Domestic producers requested United States negotiators to incorporate a commitment to implement Opinion No. 256 principles at the ERA in the FTA's implementation plan.[208]

2. Discount and Market Share Contracts

TransCanada Pipeline holds a long term supply contract with Minegasco, an LDC in the Minneapolis-St. Paul area.[209] The selling price is based upon a 7 percent discount from the interstate pipeline's sales tariffs.[210] This arrangement is claimed to prevent domestic suppliers from effectively competing with Canadian prices, regardless of how far Northern "markets-out," i.e., reduces prices to market clearing levels under the provision of its gas purchase contract with its domestic producers.[211] United States producers have unsuccessfully challenged this arrangement before the ERA.[212] ERA found that the contract was competitive and that rate issues not addressed in the contract were subject to review before the State Public Utility Commission.[213]

A related concern arises in the Northwest Pipeline-Westcoast Transmission agreement. A specific volume or market share commitment is made to the Canadian supplier, regardless of the price of domestic supplies.[214] In the case of Northwest Pipeline, 42.5 percent of the pipeline systems sales and 75 percent of incremental volumes were to be supplied by Westcoast Transmission.[215] According to U.S. producers, both formula rates and guaranteed market share contracts tend to insulate Canadian natural gas from market forces and distort competition in the United States market.[216] Domestic producers view such provi-

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206. *Canadian Imports Trouble IPAMS,* WESTERN OIL WORLD (July, 1988) at 12.
207. Lemay, *supra* note 197 at 5.
208. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204.
209. *Id.*
210. Minnegasco, Inc., Energy Mgmt. (CCH), 1 ERA ¶ 70,721 at 72,723 (Sept. 1, 1987), *reh'g denied,* ¶ 70,738 (Nov. 20, 1987).
211. BACKGROUND PAPER: U.S.-CANADIAN GAS TRADE, *supra* note 204 at 3.
212. Minnegasco, Inc., Energy Mgmt. (CCH), 1 ERA ¶ 70,721 (Sept. 1, 1987), *reh'g denied,* ¶ 70,738.
213. *Id.* at 72,731-32.
214. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 3.
215. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 71.
216. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204.

sions in contracts for imported natural gas as contrary to the intent of the FTA and asked that they be declared contrary to public policy.[217] At the same time, it must be considered that gas-to-gas competition from spot market sales, regardless of the source, can easily weaken such market-share arrangements.[218]

3. ANGTS Exemptions

In order to obtain private financing of the Alaskan Natural Gas Transportation System (ANGTS) pipeline, Congress accepted a proposal from the Carter Administration for a so-called "waiver package" that suspended application of various portions of the Natural Gas Act.[219] As a result, the FERC's ability to review and remedy claims of discriminatory rate practices on the pre-built pipelines is limited. United States producers claimed ANGTS tariffs resulted in domestic producers and gas consumers subsidizing the underutilization of the Northern Border (East Leg) and Pacific Interstate Transmission (West Leg) pipelines.[220] Because the ANGTS project had not been completed, United States producers sought a repeal of the ANGTS waiver package with the passage of the FTA.[221]

Alternatively, as a part of the administrative plan, it was recommended that the FERC treat transportation rate discounts on pre-built pipelines as a "below the line" shareholder expense rather than a cost that can be recovered through cost-of-service tariffs from other customers.[222] So far, FERC has declined to apply Order No. 380 and other provisions for stimulating market competition to ANGTS.[223]

4. Market-Responsive Contracts

Generally, long-term gas supply contracts were written during a period of shortage. Consequently, the parties to such agreements saw stability of supply and volume of purchases as taking priority and did not include the flexibility to be totally market responsive. Interstate pipelines and domestic producers have attempted to respond to market changes by renegotiating contracts in order to gain market access through transportation service. United States producers charge that in Order No. 500, FERC provided for de facto contract abrogation through the requirement of take-or-pay crediting as a precondition for transportation.[224] The question of transportation credits is discussed in FERC's rulemaking under Order No. 500 and was recast to respond to the concerns expressed by the D.C. Circuit Court of Appeals in

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217. *Id.*

218. Interview with John Smith, Manager, Joint Ventures, Northwest Pipeline Corporation, in Salt Lake City, Utah (March 5, 1989).

219. 15 U.S.C. §§ 719-719o (1988).

220. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 4.

221. *Id.*

222. *Id.*

223. *See* Order Denying Rehearing and Granting in Part Applications for Stay, *supra* note 172.

224. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 4.

Associated Gas Distributors v. Federal Energy Regulatory Commission.[225] In that case, the Court of Appeals saw an unacceptable loss in the bargaining power of pipelines with producers, without giving pipelines veto power over transportation as a means to mitigate gas supply contract take-or-pay liability.[226] As discussed earlier, FERC has not imposed comparable requirements upon imported natural gas contracts, even though many long-term Canadian contracts contain either take-or-pay or take-*and*-pay clauses similar to those found in domestic gas contracts.

United States producers want a commitment from the federal government to subject Canadian natural gas to the same market-responsive standards applicable to domestic production. A recommended solution has been to give the Secretary of Energy direction to issue a new delegation order giving the FERC exclusive jurisdiction over purchasing practices of interstate pipelines, even when the mix of imported gas is at issue.[227]

5. Exploration Subsidies and Incentives

United States producers contend that the Canadian government is providing incentives to encourage new exploration for oil and gas reserves.[228] The argument is made that absent similar incentives in the United States, Canadian policies create a bias favoring Canadian reserves in a climate of over-deliverability.[229] However, under the General Agreement on Trade on Tariffs (GATT), to which the United States is a signatory, such government assistance could become the basis for a complaint that the United States was violating the "national treatment" obligation.[230] The rationale of GATT generally is that laws and regulations should not be adopted if their purpose or effect is to discriminate against foreign and domestic goods on the basis of nationality.[231] Article 906 of the FTA clearly preserved the right of each country to develop programs to stimulate oil and gas exploration and production "in order to maintain the reserve base for these energy resources."[232]

6. Affiliate Transactions

United States marketing affiliates of Canadian pipelines are highly involved in spot market transactions. For example, the United States based Western Gas Marketing is affiliated with TransCanada and Great Lakes; and Alberta and Southern is affiliated with California operated Pacific Gas Transmission.[233] Transactions between these affiliated com-

225. 824 F.2d 981 (D.C. Cir. 1987) *cert. denied,* Interstate Natural Gas Assoc. of Am. v. Fed. Energy Regulatory Comm'n, 108 S.Ct. 1468 (1988).
226. *Id.* at 1021.
227. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 5.
228. LeMay, *supra* note 197 at 6.
229. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 4.
230. Interview with R.A. Reinstein, *supra* note 102.
231. *Id.*
232. *See* Free-Trade Agreement, *supra* note 136, art. 906.
233. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 5.

panies arguably are beyond the jurisdiction of the FERC because they are not jurisdictional "sales."[234] Domestic producers see the problem as analogous to market groups that are affiliated with interstate pipelines, in that it will always be to the affiliate's interest to engage in self-dealing rather than purchasing or transporting third-party domestic gas.[235]

Correspondingly, this group wanted a provision added to implementing legislation clarifying that sales of imported natural gas are not "first sales" within the meaning of Section 2(21) of the NGPA.[236] This would clarify FERC jurisdiction over the marketing affiliate's resales. They also sought inclusion, as a part of the plan for administrative action, of a requirement that the ERA will institute a rulemaking of marketing affiliate practices to parallel the FERC's efforts for interstate pipeline companies.[237]

7. FTA Consultation

Numerous disputes over routine matters such as accounting questions arise before the FERC and have prompted intervention by Canadian gas interests as well as the attention of the Canadian embassy.[238] The FTA provides that the parties will consult on energy regulatory actions which could result directly "in discrimination . . . inconsistent with the principles of . . . [the] Agreement."[239] Domestic producers wanted the FTA to provide for an annual consultation conference between the U.S. Secretary of Energy and the Canadian Minister of Energy recognizing the independence of the NEB and the FERC.[240]

C. Administrative and Judicial Skirmishing

In reviewing the above proposals it is significant to note the reliance which domestic producers have placed in the FERC rather than in the ERA. Perhaps some of the reluctance to vigorously pursue changes in ERA practices can be seen in recent case law. Judicial review was requested after ERA granted a blanket authorization under Section 3 of the NGA to Northridge Petroleum Marketing, a marketing affiliate of a Canadian operation, to import natural gas from Canada for a period of two years at volumes of 100 BCF per year.[241] The D.C. Circuit Court of Appeals upheld ERA reliance on its 1984 Policy Guidelines establishing the presumption of public interest which had to be

234. 15 U.S.C. § 3301(21) (1988) defines "first sales" for the purpose of FERC regulation.

235. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 4.

236. *Id.*

237. Inquiry into Alleged Anticompetitive Practices Related to Marketing Affiliates of Interstate Pipelines, 52 Fed. Reg. 21,578 (1987).

238. Interview with T. D. McGee, *supra* note 135.

239. Free-Trade Agreement, *supra* note 136, art. 905.

240. BACKGROUND PAPER: U.S.-CANADIAN NATURAL GAS TRADE, *supra* note 204 at 3.

241. Panhandle Producers & Royalty Owners Assn. v. Economic Regulatory Admin., 822 F.2d 1105 (D.C. Cir. 1987).

rebutted by the protesting party.[242] This case is also significant because a trial-type hearing was ruled unnecessary at the agency level because the challenge was to issues of policy and not " 'material issues of fact genuinely in dispute' " as required by ERA rules.[243]

The same plaintiff has been equally unsuccessful in the Fifth Circuit.[244] The domestic producers had requested that ERA require all imported natural gas to be transported by open access pipeline. Because there was no equivalent requirement for domestic production, ERA had uniformly found that such a condition would unfairly discriminate against Canadian imports.[245] The Fifth Circuit held that the 1984 guidelines were properly the result of interagency review by the Department of Energy, FERC and the State Department.[246] The court stated in this regard that:

> In particular, it is evident to us as it was to the ERA that there is no greater potential for discrimination in the distribution of imported gas than currently exists in the distribution of domestic gas. PPROA [the plaintiff, Panhandle Producer and Royalty Owner's Association] has not shown that affiliate relationships are more prevalent among transporters of imported gas than among transporters of domestic gas. We can only conclude, then, that a purchaser of Canadian gas faces no fewer obstacles in bringing its gas to market than does a domestic seller.[247]

ERA's conclusion that a special "open-access" requirement for imports would "discriminate against foreign suppliers of gas and those seeking to import this gas and would lessen competition in the market place" was sustained.[248] These kinds of issues will persist until domestic producers feel that they are not unfairly losing market share to Canadian competitors.[249]

VIII. CONCLUSION

Changes in U.S. and Canadian regulation have tightened the connection between supply source and market demand. The final adoption of the Free Trade Agreement, which became effective on Jan-

242. *Id.* at 1111-13.
243. *Id.* at 1113 (quoting 10 C.F.R. § 590.313(a) (1986)).
244. Panhandle Producers & Royalty Owners Assn. v. Economic Regulatory Admin., 847 F.2d 1168 (5th Cir. 1988).
245. Tennessee Gas Pipeline Co., Energy Mgmt. (CCH), 1 ERA ¶ 70,674 (Nov. 6, 1986); *reh'g denied,* ¶ 70,684 (Jan. 5, 1987); Western Gas Marketing U.S.A., Ltd., Energy Mgmt. (CCH), 1 ERA ¶ 70,675 (Nov. 6, 1986) *reh'g denied,* ¶ 70,684 (Jan. 5, 1987); Enron Gas Marketing, Inc., Energy Mgmt. (CCH), 1 ERA ¶ 70,676 (Nov. 6, 1986) *reh'g denied,* ¶ 70,684 (Jan. 5, 1987).
246. *Panhandle Producers,* 847 F.2d at 1174.
247. *Id.* at 1177.
248. *Id.* (citing Tennessee Gas Pipeline Co., Energy Mgmt. (CCH), 1 ERA ¶ 70,764 at 72,605 (Nov. 6, 1986) *reh'g denied,* ¶ 70,684 (Jan. 5, 1987)).
249. *Canadian Imports Trouble IPAMS, supra* note 206. David Wilson of IPAMS contends that federal regulation should require pipelines to impose mileage as opposed to "postage stamp" rates for transportation services as a means for maintaining local or regional markets. *Id.*

uary 1, 1989, more than institutionalizes the market adjustments in cross-border natural gas trade which have been occurring since 1984 in response to decontrol initiatives. The consultation provisions of the FTA should prevent the recurrence of regulatory actions like Opinion No. 256, which impose unnecessary limitations on market relationships.

Regulatory intervention in the natural gas industry reached it height in the 1960s. The latest steps toward reduced economic regulation continue a trend started in the 1970s.[250] In the need to reform governmental controls over energy, regulatory bodies such as FERC and ERA have ventured beyond the laborious Congressional process. For example, with all the restructuring that has occurred in the natural gas industry in the last five years, only the repeal of the Fuel Use Act was achieved by Congressional action.[251] Whether this ambitious administrative approach will have lasting success without clear statutory authority remains questionable.

In Canada the dimensions of decontrol were even broader than the traditional tension between regulator and industry. The very nature of the Canadian federal system required that regulatory proposals by the NEB be preceded by intergovernmental agreements with the three major natural gas producing provinces. Execution of the *Western Accord* on March 25, 1985, and the Agreement on Market and Prices shortly thereafter clearly fixed market-responsive prices as the goal to be achieved by unraveling an elaborate set of procedures that previously controlled natural gas exports. Yet, with a less complicated pipeline transmission system and smaller market to serve, Canada appears to have achieved a greater level of deregulation than the United States.

The U.S.-Canada Free Trade Agreement (FTA) embodied the principle that the economics of the marketplace should govern the level of trade between the two countries in energy goods. The energy provisions of the FTA assure that neither country will erect regulatory barriers to future incremental growth in natural gas imports from Canada. Most importantly, if supplies tighten, trade cannot be constrained below proportionate levels. Additionally, the FTA did not alter current or future production incentives of either country.

The FTA established a formal consultative mechanism for reviewing "energy regulatory actions" that result in discrimination against the other nation's energy goods. The possible breach of the FTA by regulatory action from the FERC's decisions and reprisals by Canada is a lingering concern. The actions of the FERC and ERA in the United States and the Canadian NEB are squarely within the scope of any requested consultation. The harmonization of rate design is a certain topic for these discussions.[252]

250. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 74.
251. P.L. 100-42, 101 Stat. 311 (May 21, 1987).
252. Interview with Andrea K. Waldman, *supra* note 105.

Imported Canadian natural gas will continue to claim a larger share of the U.S. market with current levels doubling by 1995 to as much as 8 to 10 percent.[253] This is particularly true for the New England states and California where future growth in the use of imported natural gas is dependent upon new pipeline construction. Nevertheless its significance in the U.S. gas market will continue to be as a competitive alternate source of supply to domestic natural gas supplies, as well as a secure source to offset increased reliance on less reliable sources of imported oil.

Deregulation policies over the last five years in both the United States and Canada have gone a great way toward making natural gas more responsive to market conditions. This has allowed natural gas to recapture markets first lost to oil following price drops in the early 1980s and then again in 1985 and 1986. Whether these customers can be retained is heavily influenced by rate design.

The Canadian approach to market-responsive pricing has chiefly employed a straight fixed-variable rate structure. Incremental gas supplies were offered to U.S. customers under a rate structure similar to that used for Canadian sales. Competition and regulatory efficiency argue for a rate design favoring interruptible sales where large end users have the ability to switch to alternate fuels. In order to compete with fuel oil natural gas must be able to be sold at its average variable cost. FERC should pursue a rate structure for interruptible sales, i.e., spot market, which puts very little fixed cost in the commodity charge.

Although the NGA requires that pipeline rates be "just and reasonable," FERC has discretion in applying this standard. Moreover, the case law in this area recognizes this administrative flexibility. For example, the United States Supreme Court has given approval to rates calculated on the basis of average production costs.[254] This approach may not be completely certain because total deregulation of a specific class of otherwise jurisdictional sales has not been judicially sanctioned. One court of appeals has overruled an earlier effort to completely decontrol prices for certain types of natural gas.[255]

Interruptible sales made through interstate pipelines should be able to be competitively priced under an approved rate structure as long as firm customers taking gas under system supply contracts are assured that interruptible rates will not be so low as make their contribution to covering fixed costs negative.

FERC has been sensitive to its lack of statutory authority to order pipelines to offer mandatory transportation in the manner of other regulated common carriers.[256] Congress specifically rejected a similar proposal for imposing common carrier status on natural gas pipelines

253. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 42.
254. Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 611 (1944).
255. City of Detroit v. Fed. Power Comm'n, 230 F.2d 810 (D.C.Cir. 1955).
256. *See generally* 49 U.S.C. §§ 101-11917 (1982).

in the Natural Gas Act of 1938.[257] In the face of such limitations, in Order No. 500 FERC has gone so far as to authorize interstate pipelines to condition open access transportation on submittal of irrevocable offers of take-or-pay credits from producers.[258] This tactic can only be as successful as the expansion of spot market sales and the success of transportation in implementing these transactions. Looking at the substantial volume of short-term sales in 1987, and the number of major interstate pipelines which have accepted Order No. 500 certificates, it would seem to be an effective tool. As of October 31, 1988, there were nineteen open access systems and sixteen pipelines that were not "open."[259] Open access carriage is a consequence of the market control interstate pipelines had held on commodity trading as well as the natural monopoly over transportation service.

After years of debate, Congress enacted the Natural Gas Policy Act in 1978 to modify the regulatory system to permit wellhead markets to begin to set prices, but initially only for certain high-cost vintages. The bulk of new discoveries was not slated for deregulation until January 1, 1985. The second oil crisis began shortly after the NGPA was signed, dramatically raising oil prices and dashing any hope of gradual convergence between oil and gas prices during the 1978-1985 deregulation period. The NGPA represented a final policy judgement that the commodity market for natural gas was not subject to monopoly forces that required full regulatory control.

No program of direct transportation for users or producers was included in NGPA. Rather, a program of incremental pricing of natural gas was enacted that threatened to price natural gas to large end users at its fuel oil equivalent before allowing smaller consumer's prices to rise. Unfortunately, this program confirmed the strategies of many industrial users to pursue energy conservation and to switch away from natural gas.

Over 35 percent of the U.S. natural gas market has the capacity to convert to alternate fuels with relatively short lead times and pricing incentives.[260] Because of this user flexibility, most of the decontrol efforts have been focused on the spot market. The ERA's blanket authorization procedures and the NEB's after-the-fact approvals for short-term export arrangements are examples of this emphasis. It is all too evident that the adjustments are not complete when one compares the fact that over 60 percent of the natural gas sold in the United States in 1987 moved in the spot market whereas less than half that percentage of imported Canadian natural gas was accounted for in short-term sales. Regulatory practices that try to preserve the distinction

257. Reiter, *Competition and Access to the Bottleneck: The Scope of Contract Carrier Regulation Under the Federal Power and Natural Gas Acts*, 18 LAND & WATER L. REV. 1, 45-46 (1983).

258. 18 C.F.R. § 284.9(f) (1988).

259. NATURAL GAS TRENDS, *supra* note 182 at 82.

260. *Id.* at 3.

between imported natural gas under short-term and long-term contracts should be reconsidered and eliminated. The market blurs such distinctions and in some cases, spot prices were at par with, or even higher than, pipeline commodity rates, which are traditionally higher than spot gas prices.[261]

The greatest single obstacle to an orderly transition toward market-responsive natural gas pricing in the United States and Canada is the threat that openly competitive markets pose to contractual and financial agreements entered into earlier when the industry was more fully regulated. Under these agreements, pipelines have obligated themselves to take higher volumes under their long-term contracts than current market requirements. They are also committed to price levels under rate structures that have become increasingly uncompetitive with the fall in oil prices, which has occurred since 1982.

The development of a market-responsive system will be complicated by the inevitable natural monopoly elements operating at each level of the industry in both the U.S. and Canada. These factors prevent it from ever functioning in the manner of free commodity markets existing for some agricultural and mineral commodities, or even to the same extent that the crude oil market is free.[262] Interstate natural gas pipeline systems often do not have competition and will operate as natural monopolies. Thus, gas transmission will require some degree of traditional regulation in the future. Large industrial and power generation customers downstream and most producers upstream are the most competitive segments of the industry. The development of open access transportation to directly connect supplier with user offers the hope of introducing overall market discipline to these segments of the industry. Nonetheless, it will prove easier to introduce effective competition for natural gas as a commodity than for natural gas transportation.

Contract commitments for the resale to local distribution companies must be firm and supply predictable, otherwise the pipeline cannot be responsible for guaranteeing deliverability. In this context, FERC efforts to relieve the LDCs of their contract demand responsibilities through such decisions as Opinion No. 256, Order No. 380, and portions of Order Nos. 436 and 500 have been called "more [a] 'bomb throwing' exercise designed to open up the system, than they are a part of a long-term design for an ongoing market-responsive system."[263]

Regulatorily speaking, we are at a halfway point, where the concern about sanctity of contract and lessening government intervention has been said to suggest:

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261. *Id.* at 77.

262. *Light "Sweet" Crude Oil Future Contract—Cushing, Oklahoma Delivery,* N.Y. Mercantile Exchange Guide (CCH) ¶ 13,501. Crude oil contracts for future delivery on the Exchange are sold in units of 1,000 U.S. barrels for delivery in such months as are determined by the Exchange's Board of Governors.

263. A REVIEW OF THE ROLE AND OPERATIONS OF INTERPROVINCIAL AND INTERNATIONAL PIPELINES IN CANADA ENGAGED IN THE BUYING, SELLING AND TRANSMISSION OF NATURAL GAS, *supra* note 2 at 80.

> [T]hat pipelines might have two separate supply entities - one a system supply company designed to guarantee reliable supply for the traditional resale business, and a second trading company designed to compete more speculatively in the contract and spot markets with independent transportation.[264]

Development of these two sides of the pipeline's supply posture—guaranteed resale system supply on the one hand and trading on the other—requires careful segregation to prevent undue risk or monopoly price behavior being transferred selectively to the regulated portions of pipeline business. The current interest in separating the commodity and transportation services of the interstate pipelines represents a significant shift in market and regulatory preference.

The movement to freer markets in natural gas cannot alter the fact that most interstate pipelines retain their natural monopoly characteristics. Therefore, the focus of market-responsive pricing must be to provide open transportation systems for producers to compete directly for end use business. This level of competition should enable the market to determine prices and through the arbitrage of spot and term contracts send market clearing signals throughout the system.

There are other factors that are equally important to the future of natural gas use and deregulation and we should not lose sight of them. While not part of either county's regulatory agenda, they include the decline in domestic production, environmental controls, and supply security. The decline in domestic proven reserves will continue and the cost of developing deeper and more expensive resources must be judged against Canadian supplies that are already connected to the existing transportation network. Additionally, environmental policies aimed at coping with a variety of problems linked to air emissions from fossil fuels could create new markets for natural gas in the next decade and insulate existing markets from competition from alternate fuels. For example, the South Coast Air Quality Management District in California has recommended completely eliminating the use of fuel oil, distillate, and solid fuels in stationary sources of air pollution (power plants, industrial boilers, etc.) by 1995.[265] The expanded use of natural gas also serves to address the concern that Canada has repeatedly expressed to the United States about acid rain.[266] The recent development in using Canadian natural gas for U.S. co-generation projects may make this issue more compelling.

The United States currently imports approximately half of its daily crude oil requirements. Imported natural gas from Canada is far less subject to supply disruptions than resources coming from politically less stable and geographically remote areas. Since natural gas is read-

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264. *Id.*
265. NATURAL GAS TRENDS, *supra* note 182 at 8.
266. Clarkson & Smedon, *Effects of Climate Change on Water Resources,* 59 NAT'L F. at 29-31 (Winter 1989).

ily interchangeable with fuel oil, supplies from Canada are expected to play an increasing role in backing out any significant increases in oil imports.[267]

In closing, imported natural gas is in a transitory and still risky period. This risk comes from market conditions where the current state of deregulation has made the industry heavily dependent upon short-term supply arrangements. Another element of risk comes from the use of imported natural gas as a supplemental source to meet peak demands in the face of declining domestic production. While the movement towards decontrol has been healthy, it has focused on the spot market and short-term solutions. The adoption of the FTA offers a longer lasting solution for correcting market distortions in cross-border trade due to governmental policy. If judicial challenges to administrative initiatives by the FERC and ERA to open up the natural gas system are successful as they were for Special Marketing Programs in *Maryland Peoples Counsel,* and to open access transportation in Order No. 436 in *Associated Gas Producers,* comprehensive decontrol will have to come from Congress.

267. U.S.-CANADA GAS TRADE REVIEW, *supra* note 1 at 43.