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Alaska Natural Gas Pipelines: Interaction of the Natural Gas and Steel Markets

Stephen Cooney and Robert Pirog, Resources, Science, and Industry Division

March 28, 2007

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Summary

In 1976 Congress approved legislation to establish the regulatory framework for building a pipeline to bring natural gas from the Alaska North Slope to the lower 48 states (Alaska Natural Gas Transportation Act, 15 U.S.C. § 719 *et seq*.). Despite the rich deposits of natural gas and the success of the Alaska oil pipeline, the Alaska segment of a gas pipeline has never been started. To encourage its development, Congress passed in 2004 and the President signed into law the Alaska Natural Gas Pipeline Act (Division C of P.L. 108-324), which includes a federal loan guarantee of as much as $18 billion. Since then, North Slope producers, other potential pipeline developers, and the state of Alaska have been in extensive discussions on building a gas pipeline. Under a provision of the 2004 law, as no application for a certificate of public convenience and necessity for the pipeline had been received 18 months after passage of the law, the Department of Energy on April 13, 2006, began a study on alternative approaches to the construction and operation of an Alaska natural gas transportation system.

Two major issues or uncertainties may serve as economic constraints on such a major capital investment undertaking. The first is whether the price of natural gas over the long term will repay investment in a project now estimated to cost $25 billion or more, and which would not deliver gas to the major U.S. markets before 2017. Natural gas prices in the North American market are high, but volatile. Spot prices rose to more than $13 per million BTUs in 2005, then fell to less than $6 by late summer 2006. The natural gas spot price reached $9 per million BTUs in only one week during the winter 2006-07 heating season. Developments of liquefied natural gas technology and of advanced drilling technologies portend new sources of supply. At the same time, the Department of Energy's Energy Information Administration reports that the only significant increase in U.S. demand for natural gas over the past 10 years has been for electricity generation.

Secondly, the price of steel, the material to be used in building a pipeline, has more than doubled since 2003, and may account for a significant share of increased cost estimates. Earlier, the pipeline project was viewed by some observers as a possible way to boost domestic steel demand, at a time when prices were low, many major North American producers had gone into bankruptcy, and trade safeguards were in place. But the steel industry has recovered and restructured. Moreover, because of the conditions under which the pipeline would be built and operated, the gas producers' pipeline consortium has specified a grade of steel that is not yet produced anywhere commercially. The American Iron and Steel Institute (AISI) estimates that 3 to 5 million tons of steel could be required, but states that sufficient capacity can be readily developed in North America for manufacturing the necessary steel pipe. P.L. 108-324 contains a "sense of Congress" resolution that North American steel should be used in the project. ExxonMobil Corporation, one of the three developers of Alaska North Slope oil and gas, has, however, announced an agreement with two Japanese companies to commercialize a new type of high-strength steel that could reduce Alaska pipeline costs.

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Introduction

In 1976, Congress approved legislation to establish the regulatory framework for building a pipeline to bring natural gas from the Alaska North Slope to the lower 48 states. Despite the rich deposits of natural gas in Alaska and the success of the Alaska oil pipeline, the Alaska segment of a gas pipeline has never been started. To encourage development of the gas pipeline, Congress passed further legislation in 2004, including a federal loan guarantee of as much as $18 billion. Since then, the North Slope producers, other potential pipeline developers, and the state government of Alaska have been engaged in extensive discussions on building a gas pipeline.

This report focuses on two major issues or uncertainties that may serve as economic constraints on a capital investment undertaking of this major scale:

- Natural gas prices in the North American market are high, but volatile. With Gulf of Mexico production shutdowns occasioned by major hurricanes in 2004 and 2005, spot prices rose to more than $13 per million BTUs. Prices fell to less than $6 by late summer 2006. They increased again in the winter 2006-07heating season, but only once exceeded $9 per million BTUs. Advances in liquefied natural gas technology and transportation, and in drilling technologies in difficult operating environments, portend new sources of supply for the domestic market. It is not clear if the fundamental demand-supply balance in the market will sustain a high enough price over the long term to make building an Alaska gas pipeline a profitable venture.
- The price of steel, the major construction material to be used in building a pipeline, has more than doubled since 2003. Earlier, the pipeline project was viewed by some observers as a possible way to boost domestic steel demand, at a time when prices were low, global capacity was ample, the domestic industry was being protected by extensive trade safeguards, and many major North American producers had gone into bankruptcy. But the steel industry has recovered and restructured. Higher prices for steel have contributed to an estimated increase in the cost estimates for the Alaska gas pipeline from less than $20 billion to at least $25 billion. Moreover, because of the conditions under which the pipeline will be built and operated, the gas producers have specified a grade of steel that is not yet produced anywhere commercially.

Northern Natural Gas Pipelines: Issues and Alternatives[1]

Bringing North Slope Gas to Market

An Untapped Resource

Alaskan natural gas is a largely untapped U.S. energy resource. The Alaska Department of Natural Resources (DNR) estimates gas reserves in the North Slope at 35.4 trillion cubic feet (tcf), which is the energy equivalent of about 6.3 billion barrels of oil.[2] For comparison, the entire annual U.S. consumption of natural gas is approximately 20 tcf. But most of the gas produced on Alaska's North Slope, 80% of the eight to nine billion cubic feet produced annually, has been reinjected into the ground.[3] Only a small amount has been used for operations in conjunction with oil production and transportation, such as powering oil through pipelines, and other local uses.

Alaskan natural gas resources have not been developed because of a lack of cost-effective transportation to major consuming markets. Using a more stringent definition than the state, the Energy Information Administration (EIA) of the federal Department of Energy estimated that proved natural gas reserves in the entire state of Alaska were 8.2 tcf at the end of 2005. Because of the lack of a pipeline, or near-term prospects for a pipeline, the remainder of Alaska's gas reserves is commercially unrecoverable.[4]

Congressional Support for an Alaskan Gas Pipeline

Congress has established a statutory framework for an Alaska natural gas pipeline. The legislative authority for designation of an Alaska natural gas pipeline route, and for the U.S. role in the approval, construction and operation of such a pipeline, was established in the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. § 719 *et seq*.), which remains in effect. Acting under that framework, a private sector consortium planned a natural gas pipeline that would parallel the existing Alaska oil pipeline (Trans Alaska Pipeline System) from the North Slope to Fairbanks, and then head southeastward along the Alaska Highway and into Canada via the Yukon Territory, British Columbia, and Alberta. This is the proposed Alaska Natural Gas Transportation System (ANGTS), which was approved by the U.S. and Canadian governments in the 1970s.[5]

In 2004, Congress approved, and the President signed into law on October 13, 2004, legislation that amended and extended the original act (Alaska Natural Gas Pipeline Act of 2004, Division C

[1] This section of the report was written by Stephen Cooney.

[2] Alaska Dept. of Natural Resources, Div. of Oil and Gas. *Alaska Oil and Gas Report* (May 2006), p. 3-2.

[3] Natural gas pumped back into the ground enhances the flow of oil.

[4] U.S. Dept. of Energy. Energy Information Administration. *U.S. Crude Oil, Natural Gas, and Natural Gas Liquid Reserves: 2005 Annual Report* (advance summary), Table 3. EIA adheres to the standard definition that proved reserves are recoverable in today's economic conditions with today's technology. The Alaska DNR's *stated* definition substantially is the same: "Remaining reserves are oil and gas that are economically and technologically feasible to produce and are expected to produce revenue in the foreseeable future." *Alaska Oil and Gas Report* (May 2006), p. 3-1.

[5] *Ibid.*, pp. 45-46.

of P.L. 108-324).[6] This law amends the 1976 act and expands it by adding several important new provisions, including a federal loan guarantee for the project. Details of this law are discussed below.

No Gas Pipeline Is Started in Alaska

Phase I ("prebuild") of the ANGTS pipeline was actually completed in the early 1980s and is in operation. Its two legs stretch from a central collecting point in Alberta in the direction of the U.S. West Coast and the Midwest. They deliver one-third of Canada's total annual natural gas exports to the United States.[7]

But the crucial third leg, connecting the "prebuilt" network to the North Slope, has never been started. It would run for 2,140 miles, from Prudhoe Bay to Edmonton, Alberta.[8] Proposed pipeline capacity enhancements from Canada to the Midwest would increase the total length to 3,500 miles.[9] The planned ANGTS pipeline along the Alaska Highway route and the completed lower legs of the pipeline into the United States are shown in **Figure 1**.

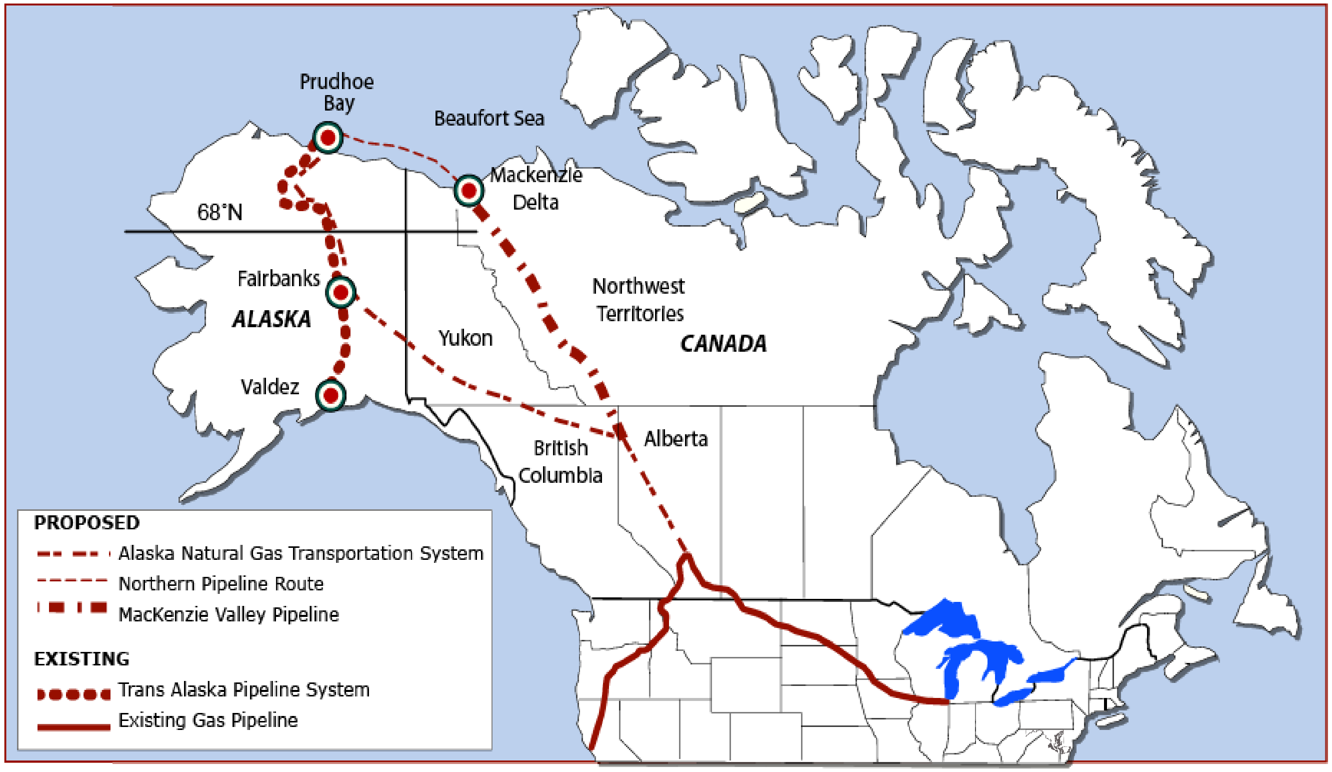
[6] Codified at 15 U.S.C. § 720 *et seq.*

[7] The "prebuild" section of the Alaska Natural Gas Pipeline in Alberta was completed by the Foothills Pipe Lines consortium. In 2003, TransCanada Corp., the major partner in the consortium, acquired 100% ownership of Foothills' interests; TransCanada Corp. website, "Alaska Highway Pipeline Project," and "Setting the Record Straight: Alaska Highway Pipeline," presentation by CEO Hal Kvisle (Apr. 7, 2005), p. 9. Also, information on the prebuilt pipeline from the former website of Foothills Pipe Lines Ltd., 2003.

[8] The length of 2,140 miles is from a chart in Arctic Resources Corporation (ARC), *The Right Solution to Tap Arctic Gas* (Nov. 12, 2002), Fig. 2. It was confirmed to the author in a CRS interview with EIA on Nov. 19, 2003.

[9] Sen. Lisa Murkowski. "Murkowski Says Gas Loan Guarantee Designed to Help Get Alaska Natural Gas to Market, Regardless of Final Project," press release, Dec. 2, 2003.

Figure 1. Alaska Oil and Gas Pipelines



Source: Adapted from CRS Report RL31278, *Arctic National Wildlife Refuge: Background and Issues*, by M. Lynne Corn et al., Figure 6, based on Energy Department maps.

In January 2004, two consortia filed proposals with the Alaska state government to build a gas pipeline along the Alaska Highway route. One group included the three North Slope oil and natural gas producers – BP PLC, ConocoPhillips, and Exxon Mobil Corporation.[10] The other group was led by the Alaska Gas Transmission Company, a subsidiary of MidAmerican, which is a major U.S. pipeline operator. But in March 2004, MidAmerican cited "the inability of the state of Alaska to complete a contract that would have allowed [our consortium] to move forward on an accelerated schedule with an exclusive five-year period," and withdrew its proposal.[11]

In June 2004, TransCanada Corporation, a Canadian pipeline company, filed its own separate application to build the complete pipeline. While Frank Murkowski, then Governor of Alaska, negotiated primarily with the producers' group, TransCanada has continued to seek a role in constructing the pipeline, emphasizing that it alone holds the right to build the segment that will cross Canadian territory.[12]

The Northern Route and Mackenzie Delta Gas

A different route to the Alaska Highway pipeline was proposed by a separate group, the Arctic Resources Consortium (ARC), based in Canada. This was the Northern Route Gas Pipeline Project. It was designed to access the Prudhoe Bay gas field in Alaska, then to swing offshore across the top of the state, under the Beaufort Sea, and to join the existing Alberta pipeline connection via the Mackenzie River (see **Figure 1**). This route also could deliver to the North American market the more recently discovered gas reserves of the Mackenzie Delta, as well as the Alaska North Slope gas.

A Mackenzie River pipeline would require a separate 1,350 mile project. ARC claimed that it could feasibly build a single 1,665-mile pipeline connecting both Alaska North Slope and Mackenzie Delta gas to North American markets.[13]

However, the northern route was opposed in both Congress and the Alaska state legislature. The Alaska legislature enacted a law that bans construction of a gas pipeline in northern state waters, while strongly supporting proposals for a pipeline to the south. It has been suggested that "... State officials see a greater gain through the income multiplier effect of construction within the state and greater access by Alaskan communities to the new gas supplies. Also at issue is the fact that a Canadian route would likely serve new Canadian gas fields, which would then compete with Alaska in U.S. markets."[14]

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[10] "Exxon," *Petroleum News* (Feb. 8, 2004), p. 10.

[11] Mid American Energy Holding Co., "Application Filed to Build Alaska Pipeline," press releases, Jan. 22 and Mar. 25, 2004.

[12] TransCanada, "Alaska Highway Pipeline Project," and "Setting the Record Straight," esp. p. 6; and, AP, "TransCanada Presents Murkowski with a Proposal," *Anchorage Daily News* (Jul. 15, 2006). According to the Federal Energy Regulatory Commission (FERC), the TransCanada proposal was made under the original 1976 U.S. law, Canada's 1978 Northern Pipeline Act, and a 1977 bilateral U.S.-Canadian agreement. The North Slope producers' proposal is pursuant to the 2004 Act and other provisions of U.S. law. FERC, *Second* and *Third Reports to Congress on Progress Made in Licensing and Constructing the Alaska Natural Gas Pipeline* (Jul. 10, 2006, and Jan. 31, 2007), pp. 1-2 in both reports.

[13] ARC, *Right Solution*, Fig. 2 and p. 7.

[14] CRS Report RL31278, *Arctic National Wildlife Refuge: Background and Issues*, by M. Lynne Corn et al.

The Senate-passed version of the energy bill in the 107th Congress agreed with the Alaskan position (H.R. 4, approved on April 25, 2002). It provided that no pipeline could be constructed for Prudhoe Bay gas that traverses the submerged lands of the Beaufort Sea, as well as its adjacent shoreline, and that enters Canada "at any point north of 68°N latitude." In a March 2003 article, Peter Behr of the *Washington Post* reported that the route along the Alaska Highway was "mandated by the Senate ... to secure the greatest number of construction jobs for Alaskans."[15]

In the 108th Congress, the House on April 11, 2003, passed a version of its energy bill, which included the same provision as the Senate on the location of the natural gas pipeline. The same provision was passed again by the Senate in the 109th Congress and became law as Section 103(d) of the 2004 Alaska Natural Gas Pipeline Act.[16] But the law also includes a "sense of Congress" provision (Sec. 114) that, as North American gas demand will continue to increase "dramatically," it will be necessary to complete a separate Mackenzie Delta natural gas project, and that "Federal and State officials should work together with officials in Canada to ensure both projects can move forward in a mutually beneficial fashion." This section further stated that, "Federal and state officials should acknowledge that the smaller scope, fewer permitting requirements and lower cost of the Mackenzie Delta project means it will most likely be completed before the Alaska Natural Gas Pipeline."[17]

The Liquefied Natural Gas Option

High prices for natural gas since 2000 have revived interest in the United States and abroad in developing liquefied natural gas (LNG) technology. LNG is gas that has been liquefied by cryogenic technology, transported in special-purpose carriers, then regasified for normal commercial use. All four LNG plants that were built in the United States in the 1970s have been reopened, and more are currently being considered, including on the U.S. West Coast.[18]

Thus, another possibility that has emerged is a new natural gas pipeline wholly within Alaska to feed an LNG operation. From there, the LNG could be transshipped by special-purpose maritime carriers to domestic or foreign markets. Alaska voters in a November 2002 referendum by 61% authorized a new state authority to build a gas pipeline to parallel the existing oil pipeline from Prudhoe Bay to Valdez, and to build a new LNG plant there. This project was promoted by the Alaska Gas Port Authority.[19] But ConocoPhillips Alaska representatives in July 2003 reportedly shared with state officials the results of an extensive multi-company industry study, which concluded that an Alaska North Slope LNG project was not commercially competitive with other LNG projects.[20]

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[15] *Washington Post*. "Natural Gas Line Proposed in Alaska," by Peter Behr (Mar. 26, 2003).

[16] 15 U.S.C. § 720a(d).

[17] 15 U.S.C. § 720*l*.

[18] Dept. of Energy. EIA. *The Global Liquefied Natural Gas Market: Status & Outlook* (DOE/EIA-0637), December 2003. For details on the emerging LNG industry see CRS Report RL32445, *Liquefied Natural Gas (LNG) Markets in Transition: Implications for U.S. Supply and Price*, by Robert Pirog.

[19] Ben Spiess, "Ulmer Authorizes Gas Pipeline Referendum for November 5 Ballot," *Anchorage Daily News* (Mar. 13, 2002), p. F4; Tim Bradner, "Voters Approve Gas Authority; Now What?" *Alaska Journal of Commerce* (Nov. 17, 2002), p. B1; FERC, *Second Report*, p. 2. San Diego-based Sempra Energy is building an LNG terminal in Baja California, Mexico, and another LNG terminal, aimed largely at the U.S. market, is being developed in Kitimat, British Columbia; see *Oil Daily*, "British Columbia's Kitimat Terminal Still Lacks Supply Deal" (Aug. 15, 2006), p. 5.

[20] Kristen Nelson, "LNG Not Cost Competitive for ConocoPhillips," *Petroleum News* (July 13, 2003), p. 2. The FERC (continued...)

Financing the Pipeline under Federal Legislation

A key question on approaches to building a pipeline is government financial support. The three major North Slope oil and gas development companies, ExxonMobil, ConocoPhillips and BP, undertook a joint study of the costs of a natural gas pipeline, especially in view of a rise in the North American price of natural gas. The study, completed in April 2002, estimated the cost of a new pipeline as $19.4 billion if the ANGTS route were used, and $18.6 billion if it followed the northern route, via the Beaufort Sea and the Mackenzie Delta. Either way, the companies concluded that the cost was prohibitive for natural gas to be commercially delivered to the U.S. market, even at relatively high natural gas price levels.[21] Subsequently, the rise in the price of steel and other factors have increased cost estimates for a pipeline along the Alaska Highway to $25 billion.[22]

In response to this question of cost, Congress has considered a number of financial measures to support construction of an Alaska pipeline. In 2002, the Senate included a $10 billion loan guarantee for private sector parties that would undertake the project (Sec. 710 of H.R. 4, as approved in April 2002), and a price floor mechanism that would guarantee a minimum price for Alaskan natural gas through tax credits (Sec. 2503 of the same bill). In the 108th Congress, the Senate Energy and Natural Resources Committee increased the Alaska natural gas pipeline loan guarantee to $18 billion (S. 14 § 144). The price floor provision was included as Section 511 of the revised Energy Tax Incentives Act (S. 1149) reported by the Senate Finance Committee.[23] The stated intention of the Energy Committee was to amend the Energy Tax Incentives Act "into S. 14 during floor action."[24]

The Bush Administration in 2002 indicated its opposition to the "price-floor subsidy provision ... and any similar provision because it would distort markets, could cost over $1 billion in annual lost revenue, and would likely undermine Canada's support for construction of the pipeline and thus set back broader bilateral energy integration."[25] The Statement of Administration Policy of May 8, 2003, on Senate energy legislation reiterated opposition to "the price-floor tax subsidy provision in the Senate Finance Committee bill, because it could distort markets and could be very costly."[26] In response, Senators John Breaux, Jeff Bingaman and Tom Daschle wrote President Bush on May 21, 2003, asking him to "reconsider" this position. The three Senators argued that, "Given the inevitable volatility of gas prices over the 50 year life of this project, this Administration position effectively means that no pipeline will be built ..."[27]

(...continued)

Third Report still lists this option, p. 1.

[21] CRS interview with ExxonMobil spokesman Robert H. Davis, April 25, 2003. The study assumed that the pipeline would be completed to Chicago, so it could be possible to effect some savings if capacity could be shared with the existing ANGTS "prebuilt" pipeline to the Midwest.

[22] FERC, *Second Report*, p. 15.

[23] See S.Rept. 108-54, part J.

[24] Senate Committee on Energy and Natural Resources. "Highlights of the Energy Policy Act of 2003 and the Energy Tax Incentives Act of 2003," press release, May 1, 2003.

[25] Secretary of Energy Spencer Abraham. Letter to Rep. W.J. Tauzin, June 27, 2002.

[26] Office of Management and Budget. "Statement of Administration Policy: S. 14—Energy Policy Act of 2003" (May 8, 2003), p. 2.

[27] Sens. Breaux, Bingaman and Daschle. Letter to President George W. Bush, May 21, 2003.

The Canadian government position has been one of declared official neutrality between the two (or more) potential routes, but opposition to any mandated, unilateral selection of routes by the U.S. government, particularly if this is included in a policy utilizing price support mechanisms for Alaskan gas, which Canada strenuously opposes.[28] Price supports and any other mechanisms that favor Alaskan gas over imports from Canada also may raise questions under World Trade Organization agreements.

The conference report of November 18, 2003, on H.R. 6 (H.Rept. 108-375) included the loan guarantee provision as approved in the Senate Energy Committee, but did not include the price floor/tax credit mechanism to reduce the risk of low natural gas prices. The loan guarantee provision was incorporated into the final 2004 Alaska Natural Gas Pipeline Act. It would authorize the Secretary of Energy to issue a guarantee within two years after a "final certificate of public convenience and necessity (including any Canadian certificates of public convenience and necessity) is issued for the project." The guarantee "shall not exceed" 80% of the total cost of a "qualified" project, up to $18 billion.[29]

According to a press report, ConocoPhillips publicly confirmed that it would not participate in the pipeline project without a price floor mechanism. An Alaska executive of the company informed a conference in Anchorage on November 20, 2003, that, "We're not going to be able to advance the project without the risk mitigation." The same press source stated that BP was still "interested" in moving forward with the project, though it would find the risk-mitigation tax credit "helpful."[30] Despite the stance, negotiations on building the pipeline continued between the state of Alaska and the North Slope producers.

In addition to the basic loan guarantee and to enhance the prospects for the LNG alternative, Senator Lisa Murkowski sought to "provide equal financial incentives" for federal support in transporting Alaska natural gas to U.S. markets, "whether that gas moves by pipeline through Canada or by tanker from Alaska's south coast."[31] She succeeded in adding to earlier legislation a provision to permit the consideration of an option providing a loan guarantee for an LNG transportation project in Alaska.[32] This language was incorporated in the 2004 Act. The portion of the Alaska gas pipeline $18 billion federal loan guarantee that could be used to cover an LNG project is limited to $2 billion. The cost of building LNG tankers could be included.[33]

Pursuit of the LNG option would entail a much shorter pipeline (the Trans Alaska oil pipeline is about 800 miles long) and, therefore, would imply use of a much smaller amount of steel. Of course, if the federal guarantee is used, an additional amount of domestic steel may be required

[28] Ambassador of Canada Michael Kergin. "Trust the Market (and Canada)," article in *Wall Street Journal*, May 15, 2002; letter to U.S. Under Secretary of State for Economic Affairs Alan P. Larson, Sept. 17, 2002. This position was confirmed in a CRS interview with Paul Connors, Energy Counsellor to the Canadian Embassy (Aug. 3, 2006).

[29] 15 U.S.C. § 720n(c)(2).

[30] Tim Bradner, "ConocoPhillips Out of Gas Line," *Alaska Journal of Commerce* (Nov. 30, 2003).

[31] Sen. Lisa Murkowski, "Murkowski Says Gas Loan Guarantee Designed to Help Get Alaska Natural Gas to Market ..." press release (Dec. 2, 2003).

[32] Description quoted from H.Rept. 108-401, p. 1180. See account in Larry Persily, "Federal Loan Guarantee Extended to LNG," *Petroleum News* (Dec. 7, 2003), p. 13.

[33] Inclusion of the cost of building LNG tankers is justified on grounds that they would have to be U.S.-built and -manned under the Jones Act, and therefore the price of construction may be "two to three times as much as foreign-built ships;" Sen. Murkowski press statement (Dec. 2, 2003). See 15 U.S.C. § 720n(a)(1), (c)(2), and (g)(4) on LNG project coverage.

for building Jones Act-qualified LNG tankers. The companies that own the gas remain less interested in an LNG project. During the administration of Alaska Governor Frank Murkowski, they focused on the Alaska Highway pipeline.[34]

State-Level Pipeline Negotiations in Alaska: A New Governor and a New Approach

Essentially rejecting both the TransCanada and LNG project proposals, Gov. Murkowski pursued an agreement with the three North Slope producers. His goal, and theirs, was to assure fiscally stable conditions under which the pipeline can be built. This has meant seeking both a long-term fiscal contract between producers and the state under the Alaska Stranded Gas Development Act, as well as changes to the state's oil and gas tax and royalty laws. A draft contract was reached in early 2006 with the producers, which provided a 20% ownership share for the state of Alaska in the primary project elements, plus royalties to be paid in gas, rather than cash. In return, the companies would have received a guarantee of a long-term stable tax rate.[35]

In August 2006, a special session of the legislature approved a new Petroleum Production Tax (PPT) regime for oil and gas producers, according to press reports. The new plan fundamentally shifted the basis of taxation, as sought by the governor and producers, from a tax on production to a tax on net profits. The new law also allowed for deductions and tax credits for new investments. Though it did not allow a deduction for building a gas pipeline, it did allow companies to deduct the cost of gas treatment plants and other infrastructure. The final law raised the tax on profits from 20%, as originally proposed, to 22.5%. It also added a surtax at any time when the price of oil is higher than $55 per barrel, and set a floor to the tax rate at 4% of gross revenues when the price of oil is low.[36]

The legislature refused to approve the draft contract in two separate special sessions in summer 2006. The oil companies' refusal so far to develop the North Slope gas fields is controversial in Alaska. For example, it is reported that ExxonMobil and its predecessor, Exxon Corporation, "which operates ... the state's largest untapped gas field ... has put off developing the field for 30 years and recently fended off a state order to submit a new development plan or face losing its leases." The producers reportedly were concerned with the amendments to the state tax regime as finally approved, and determined to secure contract provisions as favorable as possible.[37] Governor Murkowski lost his bid for re-election in the Republican primary on August 22, 2006. The natural gas pipeline contract provisions were an issue in the campaign. Even before his successor, Governor Sarah Palin, took office, the outgoing administration cancelled on grounds of non-development a major oil and gas lease held by ExxonMobil.[38]

[34] Christian Schmollinger, "Pork Barrel Language No Guarantee for Alaska LNG Project," *Oil Daily* ((Dec. 4, 2003);Associated Press, "Governor Pushes Alaska Highway Pipeline Route ..." *Anchorage Daily News* (Dec. 2, 2003), p. F2; Tim Bradner, "Pipeline Firms Eye Highway Line," *Alaska Journal of Commerce* (Dec. 14, 2003), p. B1.

[35] FERC, *Second Report*, p. 2.

[36] *Oil Daily*, "Alaska Legislature Approves New Tax Regime for Oil Producers" (Aug. 15, 2006), p. 5.

[37] *Ibid.*, and "Alaska, Exxon Headed for Showdown on Point Thomson" (Oct. 6, 2006), p. 5; "Candidate Knowles calls for caution on Point Thomson Standoff" (Oct. 11, 2006), p. 5.

[38] FERC, *Third Report*, p. 4. This action may be legally challenged.

Gov. Palin announced a new approach to achieving a privately built pipeline. She proposed in March 2007 the "Alaska Gasline Inducement Act," designed to replace the Alaska Stranded Gas Act. Her approach would establish a new competition under which all applicants willing to accept conditions of the law would be invited to submit their plans for the pipeline. Requirements include acceptance of a three-year "open season," in which the pipeline licensee would solicit firm commitments from all parties to ship gas on the pipeline. Applicants must also commit to a firm date by which they would apply for a final certificate authorizing the pipeline. Under AGIA, the state would match the licensee's costs in seeking certification up to a level of $500 million. After the first gas is shipped through the pipeline, the state would also promise a ten-year tax holiday for the pipeline operator under the AGIA. The state PPT would remain in effect under Gov. Palin's plan, but subject to future review.[39]

As stated by FERC in its *Second Report*, "When the commercial project emerges [from negotiations between the state of Alaska and producers, and from the fiscal framework legislated by the state], DOE will proceed with structuring the loan guarantee."[40] FERC further estimated that it would be at least 10 years after any contract is approved before gas would flow from Alaska to the lower 48 states.[41] Moreover, in its *Third Report*, FERC concluded in January 2007 that:

> ... [N]o pipeline application has been developed, and the prospects of an application are more remote than a year ago. Over the past year the schedule for an Alaska gas pipeline has slipped considerably. The main obstacle to progress is the failure to resolve state issues necessary before a project sponsor will commit to go forward. The fresh competitive approach announced by the new governor must be successful if Alaska gas is to be part of the nation's energy supply solution anytime in the coming years.[42]

The Department of Energy on April 13, 2006, started a study of alternative approaches to the construction and operation of an Alaska natural gas transportation system. Such a study was required under Section 109 of the 2004 Alaska Natural Gas Pipeline Act, if no application for a certificate of public convenience and necessity for the pipeline had been received 18 months after passage of the law in October 2004.[43] The study includes consultations with the Army Corps of Engineers and the Treasury Department. The study, reported in September 2006 to be in a "pre-scoping" phase, may include consideration of establishment of a federal corporation to construct the pipeline project. The results of the study and any recommendations, including proposals for legislation, are to be submitted to Congress.[44]

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[39] Gov. Palin's bill is described and defended in various release from her office: "Gov. Palin Unveils the AGIA" (news release 07-045), Mar. 2, 2007; "Weekly Gasline Briefing #4" (Mar. 2, 2007) and #5 (Mar. 8, 2007); "Executive Summary of AGIA" (Mar. 5, 2007); Gov. Sarah Palin, "Gasline Inducement Act Is Ready to Go," *Fairbanks Daily News-Miner* (Mar. 4, 2007). For a press analysis, see "Palin Bets Her Image on Gas Line," *Juneau Empire* (Mar. 11, 2007). Note that federal regulations for the "open season," as established by FERC have been legally challenged by the North Slope producers on some specific points; FERC, *Third Report*, pp. 5-6.

[40] FERC, *Second Report*, p. 7.

[41] *Ibid.*, pp. 11-12.

[42] FERC, *Third Report*, p. 7.

[43] 15 U.S.C. § 720g.

[44] FERC, *Second Report*, p. 7; *Petroleum News*, "Federal Regulators Move on Gas Line" (Sept. 24, 2006), p. 4.

Progress on Canada's Mackenzie Pipeline Project

As noted above, Congress, when approving the 2004 Alaska pipeline law, found that there was ample demand in North America for gas from both Alaska and the Mackenzie River Delta of Canada, and that both projects should go forward. Moreover, gas from the Mackenzie Delta may be used as fuel for the major oil sands project in Alberta, rather than for consumption elsewhere in North America. However, there is some possibility that moving forward simultaneously with the Mackenzie and Alaska pipelines could create a competition for both steel and labor, and thereby drive up the costs and create delays for both projects.

As currently planned, the Mackenzie pipeline would be about 800 miles long, and would consist of 30-inch-diameter pipe of a grade that is presently available commercially. The pipe would be mostly above ground, because of the difficulties in constructing and maintaining a pipeline built through permafrost. The anticipated delivery rate of the pipeline would be 1.2 billion cubic feet per day (bcf/d), if built under current plans, compared to total current production in Canada of 17 bcf/d. If more gas is found than currently anticipated in the Mackenzie Delta region, plans are that the pipeline could be looped along the same route.[45]

Current plans are that all of the Mackenzie gas would be devoted to the Alberta oil sands project. Natural gas is the primary fuel for that project. Current usage by that project is only about a half-million bcf/d, but when the project is built out to planned full capacity by 2015, the natural gas requirement would be 2.1 million bcf/d, or more than the anticipated throughput of the Mackenzie pipeline. At that time, total nominal capacity of the oil sands projects would be 4.4 million barrels of oil per day (mbd), though official projections by the Canadian National Energy Board are for an average peak output of 3.0 mbd. The oil sands project is calculated to achieve a required return of 10% on the projected capital investment, as long as the price of oil is at least in the range of $30-35 per barrel.[46]

FERC found that development of the Mackenzie pipeline "poses certain problems and risks to an Alaskan project." This not because direct competition in the gas market, but because of a lack of sufficient pipeline grade steel and a shortage of skilled labor required to build two technically challenging Arctic projects of such magnitude at the same time.[47] Both FERC and the Canadian government emphasize that the project has been expedited by creation under Canadian law of a "Joint Review Panel," which is considering all environmental and social aspects of the project, and plans to produce a final report to the National Energy Board (NEB) in 2007. One potentially contentious issue that remains unresolved is provision of an acceptable level of access to and benefits from the project for aboriginal peoples who live in and near the Mackenzie Valley.[48] If all these issues could have been resolved along the time line projected by the Canadian government, the Mackenzie pipeline could be finished by 2012, before the peak of construction activity projected for an Alaska pipeline.[49]

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45 Connors interview, Canadian Embassy; FERC, *Second Report*, p. 9.

46 Govt. of Canada. National Energy Board (NEB). *Canada's Oil Sands: Opportunities and Challenges to 2015—An Update* (June 2006), pp. 5, 12-13, 16-18. However, the report notes an 88% increase in the estimated cost of natural gas used in the project in less than two years since the first report issued by the Board, and the consequent intensification of efforts to develop alternate energy sources.

47 FERC, *Second Report*, p. 9.

48 Canadian Embassy interview.

49 Ibid., pp. 9-10; NEB, esp. fig. 6.2; Canadian Embassy interview.

But concerns about rising costs may contribute to further delays in approval of the Mackenzie gas project. It has been reported that the Joint Review Panel process has already led to a delay of one construction season in the project, and that cost estimates for the pipeline will increase from $C7.5 billion to $C10 billion in detailed project estimates being prepared by Imperial Oil of Canada, an ExxonMobil affiliate active in both the oil sands and Mackenzie gas projects. A private sector analyst, quoted in the same article, estimated that development of Mackenzie Delta gas is only economic if crude oil is in the range of $60-70 per barrel and natural gas is $7-9 per million BTUs.[50]

In keeping with the expected rise in pipeline costs, recent estimates presented by Imperial Oil with respect to the budget and time line for the overall Mackenzie gas project indicate that:

- The Mackenzie Pipeline will not receive a permit before 2008;
- Construction will not begin before 2010;
- Construction would require four years, and not be completed before 2014;
- There is presently not enough gas expected to be recovered from the mackenzie fields to fill the pipeline, and additional supply would need to be committed from other fields that may be nearby.[51]

If the Mackenzie pipeline project does not go ahead, there should be no impact on the Alaska project. But if the Mackenzie project is further delayed before proceeding, it may lead to increased costs and delays in keeping with FERC's concerns, should the Alaska project be constructed simultaneously.

Evaluating an Alaskan Pipeline Investment Project[52]

Large scale capital investment projects, such as an Alaskan natural gas pipeline, typically require substantial financial commitments at the inception of, and in the early years of, the project and promise to provide net profits to investors for many years into the future. For this reason, before undertaking such projects, investors use financial tests such as net present value analysis, that seek to determine whether, for any particular project, the value today of the proposed investment funds, are less than, or greater than, the discounted future profit stream. The principal financial advantage to having funds currently available is that they can be invested in financial assets and earn a market rate of return.[53] A key factor in evaluating capital investment project decisions is whether this financial return, which is given up, or traded off, is compensated by the potential earnings of the real capital investment.[54]

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[50] *Petroleum News*, "Costs Pose Threat" (Sept. 3, 2006), p. 1.

[51] *Ibid*., "Make-or-Break Mac Budget" (Mar. 18, 2007).

[52] This section was written by Robert Pirog. The purpose of this section is not to carry out an analysis of the economic viability of an Alaskan natural gas pipeline project. The purpose is to highlight those factors which might influence the viability of the project, and to tie them to understanding developments in the natural gas and steel industries and markets.

[53] This rate of return may vary depending on the class of financial asset chosen for investment. However, the financial rate of return is generically referred to as the rate of interest.

[54] The most common investment test is net present value analysis. This technique compares the inflation adjusted net discounted profits of the project over time to the initial investment. If the net present value of the project is greater than (continued...)

Because of the nature of the net present value investment test, any factor that affects the revenue the project might earn, or the costs that the project might accrue, is likely to affect the determination of whether the project is profitable and likely to be implemented. In the case of an Alaskan natural gas pipeline, the key market factors are likely to be natural gas prices and consumption levels, which will largely determine the revenue derived from the pipeline, and the price and availability of steel required to construct the pipeline, which is a major part of projected costs.[55] As a result, analyses of the natural gas and steel industries and markets carried out in this report can contribute to understanding the nature of the debate concerning the need for, and economic viability of an Alaska natural gas pipeline. Additionally, these analyses can identify the factors that determine the risk of the project. In a large scale project that could have economy-wide implications, such as an Alaskan natural gas pipeline, risk sharing may be one approach for government policy concerning the project.

Pipeline Returns

An Alaskan natural gas pipeline's main purpose is to deliver natural gas supplies from fields at the North Slope of Alaska to consuming markets in the lower 48 states. This natural gas is now "stranded" in the sense that it can be physically produced, but cannot be delivered to consumers because of the lack of a transportation system. Currently, the gas is not wasted: it is re-injected into oil wells operating in the area, increasing the productivity of those wells.

The key factors determining the returns, or revenues, that might be earned by an Alaskan natural gas pipeline are the expected price of natural gas over the life of the pipeline, the quantity of natural gas that might be delivered through the pipeline each year, and the number of years that the pipeline, and the producing fields that feed natural gas into it, will be operational. These factors are all related to the current, and future, projected conditions of the natural gas market. An analysis of the natural gas market is carried out later in the report.

Pipeline Costs

The costs of an Alaskan natural gas pipeline fall into two categories: investment, or capital costs, and operating costs. A large number of factors enter into the determination of either class of costs. In a subsequent section, this report focuses on one of the main capital costs of the project: the cost and timely availability of steel pipe that would be used in construction of the pipeline. The report focuses on that cost factor because of its potential significance to the North American steel industry.

Risk Factors

In financial analysis, the riskiness of a given factor is taken to be equivalent to its variability.[56] If the value of a factor is taken to be constant, this implies that the factor is risk free. If its volatility

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(...continued)

zero, *ie*. discounted profits are greater than the initial investment, the project qualifies for implementation.

[55] An additional factor is the availability of skilled labor to construct and operate the pipeline, a factor not specifically analyzed in this report.

[56] Gitman, Lawrence J., *Principles of Managerial Finance,* 8th ed., Addison-Wesley, 1997, p.228.

is low, its riskiness is low, and if the factor's value demonstrates high volatility, this is associated with high levels of risk.[57] Generally, higher levels of risk associated with a capital investment project must be compensated with higher levels of expected return if the project is to be approved for implementation through application of the net present value criterion.

In relation to an Alaskan natural gas pipeline, several of the key market factors that will determine the expected revenues and costs are likely to exhibit considerable risk. These factors include the price of steel to be used in the construction of the pipeline, the near and long term price of natural gas, and the price of labor, both for construction and operation of the pipeline. The demand for natural gas has been projected by many analysts to be relatively assured, but available historical and current market data suggests that it too might better be considered as subject to risk.

The relationship between risk factors and the viability of an investment decision may be of importance when evaluating whether public policy measures to encourage carrying out of the project are appropriate. If the benefits of a project are captured in their entirety by the investors, there is little reason for active public support. However, if the completion of the project is judged to include significant public benefits, then there may be a case made for active support of the project through public support.

Public support for an investment project might occur through loan guarantees, direct investment participation, price and regulatory guarantees, policies which encourage demand for the delivered product, and the discouragement of substitute products or services. However, critics argue that if the market will not support the economic viability of the project, neither should the government. Some of these policy options were discussed in an earlier section of this report.

Market Conditions in the Natural Gas Markets[58]

An Alaskan natural gas pipeline is unlikely to come online before 2016, and from that point, its throughput is likely to be a part of U.S. natural gas supply through the middle of the century. As a result of this long time frame, analyzing the likely values for risk factors associated with the project may come from both future projections of market behavior as well as historical trends.

Long Run Natural Gas Markets: EIA's Projections

A widely used long run projection of energy markets is the EIA's *Annual Energy Outlook 2006* (AEO), which provides market projections and analysis out to 2030.[59] The AEO reference case projects aggregate U.S. natural gas demand to rise by about 20% from 2004 to 2030, from 22.4 trillion cubic feet (tcf) to 26.9 tcf in 2030.[60] Almost all of the gains in demand, approximately

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[57] The volatility based definition of risk includes favorable as well as unfavorable movements of the factor. For example, the market price of natural gas might decrease, or increase, by 10% in a month. Either movement in the price would be consistent with identifying the price of natural gas as a risk factor.

[58] This section was written by Robert Pirog.

[59] The *Annual Energy Outlook 2006* is not a forecast, it is a projection. It is in the form of a baseline; a projection of what might occur if current conditions and policies remain in place and no new policies, or new extraneous conditions affect the market.

[60] In addition to the reference case, the AEO includes high and low economic growth and high and low price cases. (continued...)

18%, are projected to take place by 2017, with less than 2% growth, relative to 2004, taking place from 2018 through 2030. The AEO projects this growth in demand to be led by electricity generators demand growth through 2019, with more limited growth in the residential, commercial, and industrial sectors, due to the effect of higher projected prices. The AEO's 4.5 tcf projected demand increase provides the demand-side basis for the construction of an Alaskan natural gas pipeline, which itself would deliver approximately 1.5 tcf per year.

The AEO projects a changing mix of supply sources which might meet U.S. demand. Conventional onshore production of natural gas in the lower 48 states is projected to decline by about 10% from 2004 to 2030 to 4.2 tcf. Production from the shallow waters of the Gulf of Mexico is also projected to decline, by about 25% from 2004 to 2030, to 1.8 tcf. Onshore production from unconventional sources in the lower 48 states is projected to increase by about 27% from 2004 to 2030, to 9.5 tcf while deepwater production from the Gulf of Mexico is expected to increase by about 78% from 2004 to 2014, and then decline by about 35% from 2015 to 2030.[61] Over the period 2004 to 2030, deepwater Gulf of Mexico production is expected to increase by about 17% to 2.1 tcf. In 2030, Alaskan natural gas production is projected to total about 2.1 tcf. This mixture of decreasing and increasing supply sources provides the supply-side basis for the construction of an Alaskan natural gas pipeline.

Imports of natural gas by pipeline from Canada are projected to decline by about 44% from 2004 and 2030, to 1.8 tcf. Net imports of LNG are projected to increase by about 42% from 2004 to 2030, to 4.4 tcf. In the AEO reference case, both the Alaskan natural gas production and the LNG totals are dependent on major capital investments taking place over the next ten years: a pipeline in the case of Alaska and receiving terminals in the case of LNG.

While a variety of factors, including personal income levels, industrial structure, technology, and environmental considerations are likely to affect the demand and supply of natural gas in U.S. markets in the future, the key element is price. The AEO projects the price of natural gas to decline from the 2004 levels to an average of $4.46 per thousand cubic feet (mcf) by 2016, rising to $5.92 per mcf by 2030.[62] Prices at these projected levels are likely to encourage the construction of an adequate number of new LNG terminals in the United States, as well as providing incentive to build an Alaskan natural gas pipeline, according to the AEO.

Recent History of Natural Gas Markets

Since 1998, at the aggregate level, the U.S. natural gas market has maintained the appearance of balance and stability with respect to demand, supply, and reserves. As shown in **Table 1**, consumption, production, and proved reserves have been quite stable since the late 1990s. Only the wellhead price of natural gas has shown high volatility, which might be associated with an unsettled market.

(...continued)

These differing assumptions affect the natural gas values cited in this report.

[61] Unconventional sources of natural gas include coalbed methane, tight sandstones, and gas shale.

[62] In the AEO, prices are expressed in base year, here 2004, levels. Actual, nominal, prices in the future will likely be higher reflecting the average rate of inflation over the period. However, it is not definite that the future price will merely capture inflation. Actual, observed, future prices might be higher or lower than the AEO projections, depending on relative demand and supply conditions.

Table 1. Overview of U.S. Natural Gas Market

(Volumes in trillion cubic feet; price in dollars per thousand cubic feet)

Year	1998	1999	2000	2001	2002	2003	2004	2005	2006
Consumption	22.4	22.4	23.3	22.2	23.0	22.3	22.4	22.2	21.8
Production	19.0	18.8	19.1	19.6	18.9	19.1	18.6	18.1	18.5
Proved Reserves	164	167	177	183	187	189	192	204	N/A
Wellhead Price	1.96	2.19	3.68	4.00	2.95	4.88	5.46	7.33	6.42

Source: Energy Information Administration, available at http://www.eia.doe.gov.

Consumption

The sectoral demand data, which underlie the aggregate data of **Table 1**, show that important shifts have taken place in the composition of demand, even though the aggregate totals have not changed greatly.

Consumers of natural gas fall into four major groups: residential, commercial, industrial, and electric power generators.[63] While the aggregate demand for natural gas is frequently estimated to be relatively inelastic, or unresponsive to changes in price, this may not be equally true for all sectors and may have contributed to sectoral shifts.

Residential consumer demand has declined since 1998 by about 3%, probably in response to residential gas prices that were over twice as high in 2006 as in 1998.[64] The effect of higher prices was likely offset by the trend toward more and larger homes, as well as higher consumer incomes. Residential consumers may not have tied home heating decisions to the cost of natural gas due to the lack of real-time metering and this might also have supported demand.

Commercial demand has decreased since 1998 by about 5%, in response to commercial gas prices that also were more than twice as high in 2006 as in 1998. Industrial demand for natural gas has declined by 23% since 1998 in response to increases in industrial prices for natural gas since 1998. Industrial consumption of natural gas, either for production process heating, or as a raw material, may be more price responsive than that of the other consuming sectors. Cost increases might be passed on to consumers, or they might be absorbed as lower profits, depending on the nature of the market for the industries' products. For example, an industry that is a large consumer of natural gas as a raw material and has no suitable substitute, is nitrogenous fertilizer manufacturing.[65] Also, the U.S. fertilizer industry is open to foreign competition, which prevents an easy pass-through of cost increases to consumers. It is capable of moving production overseas where natural gas prices are generally lower, likely accounting for part of the reduced demand from the industrial sector.[66]

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[63] Each of these consumer groups pay a different price per unit for natural gas. Generally, large scale consumers pay less per unit than smaller consumers. For example, the EIA reported that in June 2006 residential consumers paid $14.95 per mcf while industrial consumers paid $6.87 per mcf.

[64] The residential price of natural gas was $6.82 in 1998, and $13.76 in 2006.

[65] See *Domestic Nitrogen Fertilizer Production Depends on Natural Gas Availability and Prices* , GAO-03-1148, September 2003, for a further discussion of the effect of natural gas prices on the nitrogen fertilizer industry.

[66] Imports of fertilizer by the United States have increased from an annual rate of $3.2 billion in 1997 to $8.2 billion in 2006 and the United States has shifted from a net exporter to a net importer.

The demand for natural gas by electric power generators has increased by about 36% from 1998 to 2006. Since the early 1990's, technology, emissions performance, the availability of long term contracts, and low prices for part of the period have favored natural gas as the fuel of choice for new generating capacity. Household and commercial demand for electricity is relatively price inelastic because of the nature of its use in the home, and in businesses, as well as the lack of real time metering to allow users to determine the true cost of their electricity use decisions.

An important question in the evaluation of an Alaskan natural gas pipeline is whether its role will be to allow demand growth for all, or part, of the 26.9 tcf projected demand in 2030, or whether its role will be to replace diminished production from currently existing sources, or both. One scenario could begin with the assumption that demand patterns observed over the past nine years will continue in the future. This approach would have residential and commercial demand nearly flat, electric power demand increasing, and industrial demand decreasing. Industrial demand decreases have been large enough to offset growth in electric power generation because, among the sectors, industry is the largest user of natural gas. Another scenario might be that those uses of natural gas in the industrial sector that are price responsive will be exhausted at some level, and after that usage level is attained, industrial demand would not decline as rapidly in response to price as in the past. Thus, demand would rise over the next decades. On balance, reviewing the period since 1998, it is not clear whether aggregate U.S. demand growth could provide the major justification for an Alaskan pipeline.

Production and Imports

Production data for U.S. natural gas production shown in **Table 1** indicates that although year-to-year variations exist, there does not appear to be a clear upward or downward trend. U.S. production decreased by about 5% between 2000 and 2005, but by only by 2.6% over the period 1998 to 2006. Peak U.S. production levels were attained in 2001, near the beginning of the period of volatile, escalated prices. Production is likely related to price, but technology and the geological characteristics of the gas fields also play an important role in determining output.

The difference between U.S. production and U.S. consumption is made up by imports, mostly by pipeline from Canada. The natural gas market, unlike the crude oil market, is regional rather than global in scope, extending along pipeline systems. It is possible that the geographic scope of the U.S. natural gas market may expand in the coming decades through the expansion and maturation of the LNG market.

Imports from Canada increased by approximately 18% over the period 1998 to 2006. Imports of LNG increased by about 585% over the period 1998 to 2006, but still accounted for less than 3% of U.S. consumption in 2006. Imports from Canada are expected to decline in the coming decades as Canadian domestic consumption increases, more natural gas is used in the production of oil from oil sands, and Canadian fields continue to deplete. These trends could be moderated by the opening of new supplies, especially those delivered through the proposed construction of the Mackenzie River natural gas pipeline, or through technological improvements.

The United States currently has four operational LNG receiving facilities. Plans for expansion at existing facilities, coupled with the construction of new facilities could increase the U.S. consumption of LNG considerably. However, the spot market for LNG has been slow to develop on the production side, and other competing uses are vying with LNG for available natural gas feedstock supplies.[67] The market for LNG remains largely a long-term contract market.[68]

Natural Gas Reserves

Proved reserves are those reserves that are recoverable using currently available technology under existing economic conditions, including price. These reserves provide the basis for current and future production. Current production draws down the level of proved reserves, and new discoveries increase, or maintain, the level of proved reserves.

Data in **Table 1** show that the level of U.S. proved reserves of natural gas has increased by approximately 24% over the period 1998 to 2005. Another key measure of the production base is the reserve-to-production ratio. In 1998 this ratio was 8.6, implying that at then-current production rates the reserve base could sustain production for 8.6 years. By 2005, the reserve-to-production ratio had increased to 11.2, implying that the reserve base could sustain U.S. production levels longer than in 1998.[69] This increase came after the production of over 133 tcf from the U.S. reserve base during the period 1998 to 2004. Natural gas discoveries have more than replaced production draws during this period.

As noted by the EIA in the AEO, the sources of U.S. gas production are moving away from conventional, onshore to more costly unconventional and deep offshore supplies, which may imply an upward trend in the price of natural gas, but also suggests that availability is not likely to be sharply reduced relative to current levels.

Natural Gas Prices

The wellhead price data presented in **Table 1** suggests that prices have generally been rising since 1998, with a good deal of volatility. Notable was the decline in prices in 2002, consistent with the downturn in U.S. production that year, but seemingly at odds with the increased consumption that year. Since 2003, the price trend has been upward and volatile, with wellhead prices peaking above $10 per tcf in both October and December 2005, before moderating in 2006.[70]

The wellhead price of natural gas has risen by about 225% over the period 1998 to 2006. Price increases of this magnitude might ordinarily be associated with a major change in the underlying market fundamentals. If consumption demand had increased markedly, or production had diminished, or even if the reserve base upon which consumption and production are based had been reduced, sharply affecting expectations for the future, then the change in price could be

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[67] See CRS Report RL32666, *The Gas to Liquids Industry and Natural Gas Markets*.

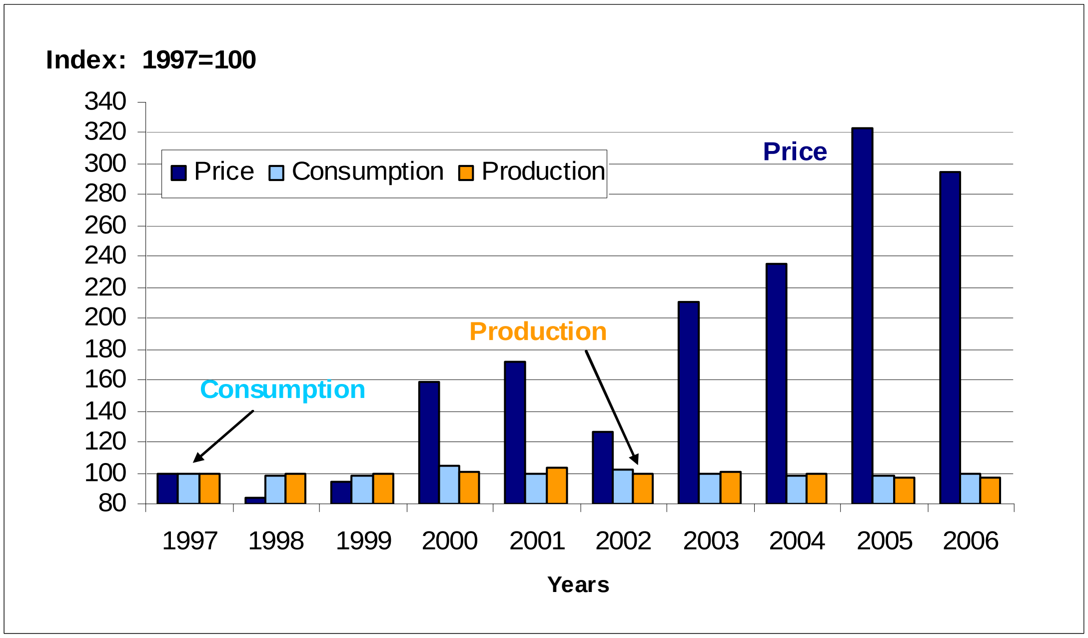
[68] See CRS Report RL32445, *Liquefied Natural Gas (LNG) Markets in Transition: Implications for U.S. Supply and Price*, by Robert Pirog.

[69] In recent years, the overall industry reserve-to-production ratio has been about nine years.

[70] Monthly natural gas price data is affected by a wide variety of short run forces which affect the market. Weather, a highly variable factor, can affect monthly prices by creating unexpected changes in the average draw from, or injection into storage, as well as consumption. Extreme weather conditions, such as hurricane Katrina, have also been shown to be able to affect natural gas production adding more volatility to price.

explained in terms of normal market demand and supply adjustment.[71] However, the data presented in **Figure 2** is seemingly more consistent with market stability than upheaval.

Figure 2. U.S. Natural Gas Price, Consumption and Production Indexes



Source: Energy Information Administration, available at http://www.eia.doe.gov. Index computed by CRS.

Note: 2006 indexes estimated from data for January-June 2006.

Other explanations for the pattern of natural gas price movements since 1997 include the effects of financial trading of natural gas futures contracts. One approach suggests that the increased interest in natural gas markets by financial traders in itself has caused prices to rise. Another approach claims that speculators have used illegal strategies to create artificial prices in the natural gas market.

In a recent study, Mark N. Cooper investigated the case for influence by financial traders on natural gas prices.[72] Cooper identifies what he sees as a pattern of increased interest in natural gas trading by financial investors and movements in the wellhead price of natural gas. For example, Cooper notes that while the price of natural gas was relatively stable in the 1990s, it began to increase in the spring of 2000, a period coincident with the expansion of natural gas trading on

[71] The prices of crude oil and natural gas usually stand in a 6:1 ratio based on energy content. That is, the price of a barrel of crude oil is six times the price of 1 mcf of gas. During 2006, the ratio has been over 10:1, although this is likely due to the price of crude oil rising to reflect geopolitical uncertainties and the tight demand/supply balance in the world oil market.

[72] Mark N. Cooper, *The Role of Supply, Demand and Financial Commodity Markets in the Natural Gas Price Spiral,* prepared for the Midwest Attorneys General Natural Gas Working Group, May 2006.

the Enron Online trading platform.[73] Cooper also notes that after Enron's departure from the market in December 2001, the wellhead price of natural gas declined in early 2002.[74]

While Cooper's study presents examples of possible correlation between movements of natural gas prices and financial trading patterns, he does not carry out statistical analysis that might demonstrate more conclusively causal links between the two sets of data. Irrespective of the effect on price, the trading of natural gas futures contracts does allow consumers and producers of natural gas to re-distribute the price risk they face to speculators who are more willing to bear that risk.

Studies undertaken by the New York Mercantile Exchange (NYMEX) and the Commodity Futures Trading Commission (CFTC) present conclusions different from Cooper. Both studies are limited to the regulated, standard contract part of the futures and derivative market. The over-the-counter segment of the futures and derivatives market is exempt from regulatory oversight. The NYMEX study found that hedge funds comprised only a modest share of trading in natural gas futures contracts and their activities were not a likely source of excess volatility in the market.[75] The CFTC study found that hedge fund trading on energy futures and derivatives markets and commodity prices were not linked, and that price volatility was not increased by their trading activities.[76] Unlike the Cooper study, the NYMEX and CFTC studies are based on extensive statistical analysis of price and other market data.

Uncertainties

Comparison of the AEO projection of natural gas market conditions to the actual performance of the market over the past nine years yields differing pictures of the market itself, as well as conditions for an Alaskan natural gas pipeline.

This report has identified the future natural gas price, the quantity demanded, and the output levels of existing gas production sources as key risk factors in evaluating the economic feasibility of an Alaskan natural gas pipeline. These factors are interrelated in the sense that they each help determine the other's value. If an Alaskan natural gas pipeline is constructed, and either new demand is not created, or existing production sources do not decline, or are replaced with gas from other more technically or economically viable sources, the 4.5 billion cubic feet of gas per day the pipeline will be capable of delivering could depress the market price. In this scenario, the economic viability of the pipeline would be in danger as well as that of other relatively high cost sources of gas.

LNG imports also have the potential to change the economics of an Alaskan natural gas pipeline. While the United States currently uses LNG for less than 4% of its total consumption needs, plans exist to expand currently available offloading facilities and to construct many new facilities. These facilities, are capital intensive, although for comparable capacity they may cost a fraction

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[73] The growth of the Enron Online trading platform led to both an increase in financial trading as well as being associated with the illegal activities that led to Enron's bankruptcy.

[74] Cooper, p. 8.

[75] New York Mercantile Exchange, *A Review of Recent Hedge Fund Participation in NYMEX Natural Gas and Crude Oil Futures Markets*, March 1, 2005, p.3.

[76] U.S. Commodity Futures Trading Commission, *Price Dynamics, Price Discovery and Large Futures Trader Interactions in the Energy Complex*, April 28, 2005, p.24.

of the cost of a pipeline. If they are built, and gas begins to flow through them, they could be viewed as competing for the same increase in demand that the AEO projects for the future.

Over-capacity might be a concern to the natural gas market. Residential demand growth depends on the extent of new home construction, which is just coming out of a major growth phase and slowing down. Commercial demand is relatively flat, while industrial demand is declining. To the extent that permanent demand destruction has occurred in the industrial sector, it may be unrealistic to assume any growth over the near term. Electricity generation by natural-gas-fired generators, however, is projected to continue to experience growth and provide support for the growth in natural gas demand.[77]

Short Term Market Conditions

Current, and near-term, natural gas market indicators are of limited use when planning long term capital projects in the industry. The market-fundamental-based value of natural gas in the short term is determined by the interaction of consumption, production, and stored quantities. Since production is relatively constant during any year, and consumption tends to be seasonal, stored quantities of natural gas balance the market. The primary short term direct determinant of consumption, and indirect determinant of stored quantities, is the weather. Exceptionally cold weather during the winter heating season can cause demand to surge. Exceptionally warm weather during the summer season can cause electricity demand, much of which on the margin is natural gas generated, to surge. Storage injections typically occur during the spring and summer. Storage draws typically occur during the winter heating season. If a cold winter (large withdrawals from storage) is followed by a very warm summer (below expected injections into storage), it is likely that the price of natural gas will experience upward volatility. However, this upward price movement may not be permanent, or even indicative of long term trends. A cold winter might be followed by more temperate conditions, reversing the natural gas price pressure.

Long-term economic decisions, such as the construction of an Alaska natural gas pipeline, are usually based on expected outcomes over a time period commensurate with the economic life of the project. Favorable, or unfavorable, short run conditions on the commodity market are often discounted.

The Impact of Steel Prices and Availability[78]

The Reversal in Steel Prices

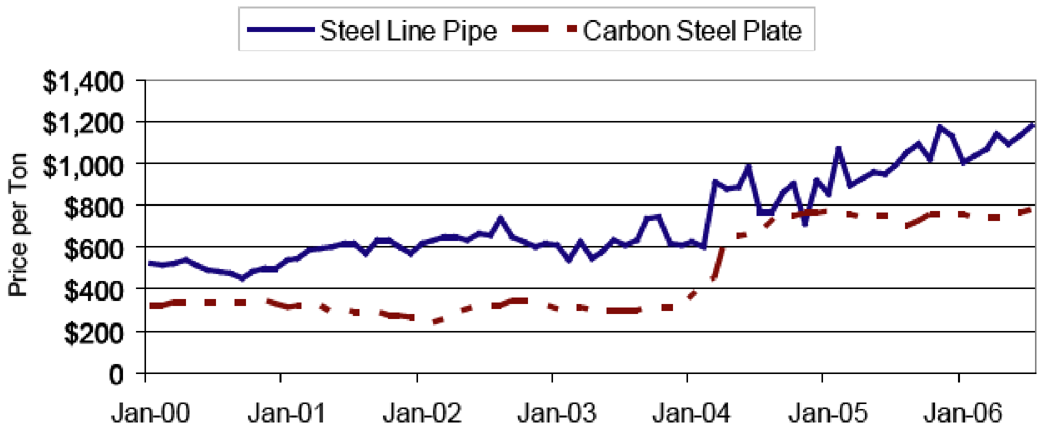
The Alaska natural gas pipeline project was supported by the North American steel industry in a period of low prices and company bankruptcies, because it could provide a boost to employment and revenues. For example, the American Iron and Steel Institute (AISI) estimated that the project could generate "up to 10,000 work years of direct employment from North American steel

[77] Many factors are likely to contribute to the potential growth in electricity demand. For example, high prices for natural gas could make coal fired powerplants competitive. Climate change legislation, if enacted, could influence the growth of electricity demand and the mix of fuels used in electricity generation.

[78] This section was written by Stephen Cooney.

supply.[79] In addition almost 4,000 additional work years would be used to manufacture pipe from steel." This estimate was based on the use of three to five million tons of steel. By comparison, AISI noted that in 1999-2000, "three North American steel pipe producers supplied over 1,000,000 tons of steel for the 2,000 mile Alliance Pipeline running from Northern British Columbia to Chicago," which AISI stated was "the most technologically advanced and largest pipeline construction project ever in North America."[80]

Figure 3. Prices for Large-Diameter Steel Pipe and Plate



Sources: *Preston Pipe & Tube Report*; Global Insight, steel plate data reported from *Purchasing* magazine.

Note: Pipe prices represent average transaction price (by weighted average value) for double-submerged arc-welded pipe > 24" diameter , combining both domestic and import shipments. Plate prices are for coiled plate.

The situation now, just a few years later, is almost totally reversed. The North American steel industry has restructured, and recovered profitability because of strong domestic and worldwide demand.[81] Now, higher prices resulting from both strong demand and increased production costs for carbon steel plate, used in making large-diameter steel pipe, may alter the basic economics of an Alaska natural gas pipeline project.

As illustrated in **Figure 3**, data reported by the consulting firm Global Insight (formerly known as DRI-WEFA) indicate that the price of carbon plate has more than doubled during the past five years.[82] As of late 2001, DRI-WEFA reported that spot prices for plate were between $250 and

[79] The phrase "North American steel" is used throughout this report and most AISI documents, instead of "U.S." steel. U.S. and Canadian steelmakers compete within the same free trade area, and the same industry union, the United Steelworkers, operates on both sides of the border. Moreover, if the pipeline were to run through Canada, participation by Canadian steelmakers in any competitive bidding process would presumably be required.

[80] Quotations from Andrew G. Sharkey, III, AISI. Letter to Sen. Frank Murkowski (April 17, 2002), with attached statement. Estimates of total amounts of steel from CRS interviews with Chip Foley, AISI, April 22 and 24, 2003. The total production of steel in the United States has recently been about 100-110 million tons per year, with imports adding roughly 30-40 million tons annually to U.S. supply; AISI, *Annual Statistical Report* (2005), figs. in frontispiece, "U.S. Steel Shipments" and p. 46, "Imports of Steel Mill Products."

[81] See CRS Report RL32333, *Steel: Price and Policy Issues*, by Stephen Cooney, for details.

[82] **Figure 3** uses a price series for coiled plate. This is the steel used for the highest grade steel pipe of the largest diameter, which is now spiral-welded. Much large diameter pipe is also made from "cut-to-length" plate. The prices of the two types of plate are close and generally move in tandem.

$300 per ton. This was consonant with an overall depression in steel prices. DRI-WEFA at the time stated that the "... composite of eight carbon spot prices sets a new low almost every month, and in the past seven years has fallen 44%."[83] Carbon steel plate was one of many steel mill products protected from imports by special tariffs, known as safeguard remedies, between March 2002 and December 2003, when they were terminated by President Bush. During 2003, steel prices began to strengthen, and carbon plate averaged $303 per ton for the year. After the the safeguards ended, steel prices escalated instead of falling, as one might expect, because of a global recovery in demand. The carbon plate price average doubled to $633 per ton in 2004. For 2005, the average price was even higher at $744, and it was still at a similar level in mid-2006. Global Insight forecasts carbon plate prices to decline over the next two years, but only gradually, and to a level still more than double the price early in the decade.[84] While the price of flat-rolled steel is expected to fall because of reduced light vehicle output by the major U.S. domestic producers, Global Insight analyst John Anton has also stated that, "Not all products will decline, as markets for structurals and plate are still tight ..."[85]

Figure 3 illustrates the parallel increase in large-diameter pipe prices consonant with the underlying increase in price of steel plate. As of late 2001 and early 2002, the price of large-diameter pipe was generally around $600 per ton. As shown in **Figure 3**, the price of coiled plate was less than half that level. By late 2005, the average reported price of large-diameter pipe was more than $1,000 per ton, with plate, now more than $750 per ton, accounting for the increase. By mid-2006, the price of pipe was approaching $1,200 per ton, with the cost of coiled plate close to $800. Moreover, availability of plate for outside-diameter pipe wider than 36" is limited in the U.S. market to one integrated mill, or possibly only to import sources. This has resulted in 2006 price quotes above $1,050 per ton, or three times the price quoted for similar product in 2003.[86]

The increased cost of steel could account for a substantial share of the increase in cost estimates for the Alaska natural gas pipeline. Actual prices for large quantities of steel pipe for major projects are negotiated by the steel supplier and seller, and are not made publicly available. But average monthly transaction prices are reported in *Preston Pipe & Tube Report*, the only data source for large-diameter steel pipe prices. In a previous section of the report, it was noted that a producers' study in 2002-2003 estimated a total pipeline cost of $18 billion to $19.6 billion for the Alaska Highway route, and that more recent estimates were at least $25 billion. An informed 2006 estimate for the tonnage of pipe needed is at least four million tons (which is also the midpoint of the estimate quoted earlier by AISI).[87] The data in **Figure 3** show an increase in the average price of steel from about $300 to about $750 per ton, and for large-diameter pipe from around $600 to about $1,100 per ton. But pipe for use in Arctic conditions would probably require the highest grade of steel available (see below), so the increase in price since the earlier project estimates were produced may be on the order of at least $500-600 per ton. That would imply an increased cost of steel pipe for the project of about $2.0-2.5 billion, which alone could account for half or more of the increase in overall project cost estimates.

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[83] Based on data from *Purchasing* magazine. DRI-WEFA. *Steel Industry Review* (4th Qtr. 2001), p. 18 and table 16.

[84] Global Insight. *Steel Industry Review* (2nd Qtr. 2006), tabs. 1.11-1.12. Even higher prices of $840-880 per ton were quoted on the West Coast, from which plate could be provided for mills to manufacture large-diameter pipe to be used in Alaska; *American Metal Market* (*AMM*), "West Sees More Steel Plate But Prices Holding Ground" (Aug. 31, 2006).

[85] Global Insight. *Steel Monthly Report* (Sept. 2006), p. 2.

[86] Interview with David Delie, Berg Steel Pipe (Feb. 15, 2007).

[87] Ipsco Inc. *Northern Pipelines* (presentation to U.S. federal agencies, Apr. 2006), p. 22.

North American Large Pipe Production Capacity

Section 111 of the 2004 Alaska Natural Gas Pipeline Act expresses the sense of Congress that, as "an Alaska natural gas transportation project would provide specific significant economic benefits to the United States and Canada ..." its sponsors "should make every effort to ... use steel that is manufactured in North America ..."[88] The relative capabilities of U.S. and Canadian industries to supply steel for the project would depend on a number of variables, including the time frame for completing the project, the final route chosen, and the pipeline specifications. The North Slope natural gas producers have indicated that they would require a pipe of maximum capacity, to ensure the ability to transport a high enough volume of gas to earn an adequate return on a privately financed system. When the 800-mile Trans Alaska oil pipeline was built in the 1970s, it used 500,000 tons of special cold-weather steel 48-inch diameter pipe imported from Japan.[89] There are a number of questions today about the capacities of the North American industry to supply the steel that might be required to construct an Alaska natural gas pipeline.

The increase in oil and gas prices in 2005-06 has encouraged North American drilling activity and increased demand for all steel products used in the oil and gas industry, including large-diameter pipe for long-distance gas transmission. But there are currently only a few large-diameter pipe producers active in North America:[90]

- Ipsco, Inc., originally a Canadian company, which now has more of its assets in U.S. mills and its operational headquarters in Illinois, is the largest North American producer of large-diameter pipe. It operates a pipe mill in Regina, Saskatchewan, with an annual capacity of 350,000 tons, and a capability to make pipe up to 80 inches wide. Plate is supplied from a mill there, and from mills in Iowa and Alabama. The company is also building a new R&D facility in Regina devoted to pipe technology. Ipsco recently announced a deal to acquire NS Group, a Kentucky-based pipe and tube manufacturer, but that company specializes in smaller diameter oil country tubular goods (OCTG) products, not large-diameter pipe.
- Oregon Steel Mills, a U.S.-based steel minimill company, currently operates a large-diameter pipe mill in Camrose, Alberta. Originally this was a joint venture with the Canadian steelmaker, Stelco. Oregon Steel acquired full control of the facility, which has an annual capacity of 180,000 tons of pipe ranging from 20 to 42 inches in diameter. Oregon Steel is also opening in late 2006 a new large-diameter pipe mill complex in Portland, Oregon. It will have an annual capacity of 175,000-200,000 tons of 24 to 60 inch diameter pipe. In January 2007, Oregon Steel was acquired by a Russian company, Evraz Steel.[91]

[88] 15 U.S.C. § 720i.

[89] U.S. Dept. of the Interior, with Argonne National Laboratory. "TAPS History," in *TAPS Renewal Environmental Impact Statement*, http://tapseis.anl.gov.

[90] Data for the following list based on Ipsco, *Northern Pipelines*, table on p. 25; Oregon Steel Mills corporate website; and, *AMM*, "A Big Backlog and Even Bigger Potential in Large-Diameter Pipe" (Sept. 11, 2006 print ed.), pp. 6-7. On the Ipsco-NS deal, see *Wall St. Journal*, "Ipsco to Buy NS for $1.46 Billion in Steel-Tube Push" (Sept. 11, 2006), p. A2; *AMM*, "Ipsco's $1.5B Buy of NS Shores Up OCTG Stance" (Sept. 12, 2006).

[91] *Ibid.*, "Evraz Given 'Go' to Pursue $2.3B Buy of Oregon Steel" (Jan. 11, 2007); and, "Oregon Steel Purchase Completed" (Jan. 25, 2007), p. 6.

- Berg Steel Pipe, a subsidiary of Europipe, jointly owned by German and French steel interests, manufactures pipe in Panama City, Florida. Berg buys domestic or imported plate for manufacturing pipe with a diameter from 24 to 72 inches. It recently announced plans to expand with a second mill along the Gulf Coast, but this would be for pipe of lesser diameter.

Ipsco and Oregon both operate minimills that supply plate for making pipe. Nucor, the largest operator of minimills in North America, makes plate at two mills in North Carolina and Alabama, and also can supply plate to customers for pipemaking operations.[92] Among the large integrated companies, both U.S. Steel and Bethlehem Steel have closed some steel pipemaking operations in recent years, though U.S. Steel makes smaller diameter pipe and tubing for OCTG applications.[93] U.S. Steel has not in recent years been a major market force in plate. In 2003, it agreed to trade its plate operation at Gary, Indiana, to Bethlehem's successor, Mittal Steel, for a different type of operation in the same vicinity.[94] According to its corporate website, Mittal produces plate at its large integrated mill in Burns Harbor, Indiana, as well as rolling plate at two plants in Pennsylvania, some of which may be supplied to makers of larger diameter pipe.[95] Both minimills and integrated steel mills since 2003 have faced much higher input costs, which have driven the price of plate higher along with increased industrial demand.[96]

These data portend a limited North American capacity in the face of a dramatic recent increase in demand for steel in pipelines. James Declusin, then CEO of Oregon Steel, stated that when his company decided to proceed with the new large-diameter pipe mill, it projected total ongoing demand for about 2.5 million tons per year—and, "Since then there have been even more projects on the drawing board." His large-diameter pipe facilities are "booked through mid-2008," and there are reports of demand remaining at a high level through 2009-10.[97] John Tulloch, a senior executive at Ipsco, noted that large-diameter pipe historically accounts for 10-20% of U.S. steel plate usage. Though "we had been at 10% or lower for a while there, now we are at the higher end of that range, much closer to 20%."[98]

The potential shortage of large-diameter pipe has led to a number of projects to expand capacity. In addition to the Oregon Steel and Berg Pipe projects mentioned above, plans have been announced by Lone Star Technologies of Texas and Welspun Group of India to build a joint venture project somewhere in the South. Two Korean companies, POSCO, which already operates a joint-venture rolling mill with U.S. Steel in California, and SeAH Steel have announced plans for a large-diameter pipe mill with a capacity of more than 300,000 tons,

[92] See "Nucor Steel—Hertford" and "Nucor Steel Tuscaloosa, Inc." on Nucor Corp. website. AISI confirmed that Nucor does supply plate for OCTG pipe applications.

[93] The Bethlehem pipemaking operation in Steelton, PA, was acquired by Dura-Bond Industries, a pipe coatings specialist, and is now operated by them. It manufactures line pipe of up to 42" in diameter. The Dura-Bond website did not report any long-distance oil or gas pipeline projects completed, nor was this facility included in the report compiled by Ipsco. The Ipsco list also did not refer to the Baytown, Texas, large-diameter pipe mill originally built by U.S. steel and acquired in the 1990s by Jindal Steel of India. Only limited information has been found on large-diameter pipe output of this mill, known as Jindal SAW Pipe.

[94] CRS Report RL31748, *The American Steel Industry: A Changing Profile*, by Stephen Cooney.

[95] See "Plate" listing under "Flat Products" at Mittal Steel USA website.

[96] CRS Report RL32333, *Steel: Price and Policy Issues*, by Stephen Cooney.

[97] *AMM*, "Big Backlog," p. 6. *AMM* also reports European pipe mills, including Berg's parent companies, booked up through 2007 or 2008; "Salzgitter Plant Sold Out of Pipe until 2008" (Oct. 5, 2006), p. 6.

[98] *Ibid.*, "Rigged for Profits," p. 5.

probably somewhere on the West Coast. Overall, it is reported that EIA estimates that by 2008 U.S. large-diameter pipemaking capacity could total 56% more than in 2007.[99] These additional mills will all use spiral-weld technology, which is newer and more efficient than straight-seam welding of large pipes, but which also may not be suitable for the special requirements being contemplated for an Alaska natural gas pipeline.

Globally, the Ipsco report also counts about three million tons of annual capacity in large-diameter steel pipe outside North America. This is divided roughly equally between the Europipe consortium in Germany (Berg's parent company) at 1.6 million tons, and three major Japanese steelmakers (Nippon Steel, Sumitomo and JFE) at about a half-million tons each.[100]

Steel industry sources emphasize that the capability of the industry to supply pipe for the Alaska natural gas project will also depend on the timing and specifications for the pipe. The maximum diameter being considered is 52 inches, capable of delivering 6.0 billion cubic feet of gas per day (bcf/d), as indicated in data provided by AISI. But 52-inch pipe has only been produced in very limited amounts in North America (or anywhere else). Moreover, the Alaska natural gas producers in the pipeline consortium have indicated that they want to specify a measure of strength, X100 or X120 grade pipe, that is beyond the X80 grade—currently the highest available.

In its report, Ipsco flatly stated that, "No North American producer can currently supply the pipe proposed for the Alaska pipeline ... no pipeline operating uses these specifications ... if the line is as specified today (48"-52" [diameter] x 0.80" [thickness] x X100), we are not able to supply the pipe without major capital expenditures and lead time." The company added that it was "proceeding with X100 trials," but that the specifications would require "designing out of market capability." Moreover, "due to extremely large volume [it is] very unlikely [that] it will be supplied by one supplier ... [and the] proposed gauge and grade requirements will necessitate capital investment by any potential supplier throughout the world."[101]

Use of this size and grade of pipe would create logistical complexities in pipeline construction and operation, requiring, for example, 48 compressor stations along the Alaska route. Using a 48-inch pipe might reduce operational and construction difficulties somewhat, and it could be made from X80-rated steel, but would reduce capacity to 4.0 bcf/d. Downsizing to a 42-inch pipe would substantially reduce pipe manufacturers' retooling costs, but would also reduce capacity to 2.0 bcf/d.[102] By comparison, construction and operational difficulties would be much less along the Mackenzie River route. Only 10 compressor stations would be required along the river valley route, and a total of only 465,000 tons of 30-inch mainline pipe, which, for example, Ipsco states it could now provide commercially. Ipsco was also the largest supplier of pipe for the Alliance pipeline cited by AISI, and delivered 716 miles of 36-inch, X70 pipe.[103]

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[99] *Ibid.*, "Strong Demand Spurs Flood of Large-Diameter Pipe Projects" (Feb. 12, 2007), p. 4.

[100] Ipsco, *Northern Pipelines*, pp. 24-25.

[101] Ipsco, *Northern Pipelines*, pp. 14-15, 22-23. In an interview with CRS, an Ipsco representative pointed out that the 4 million ton figure was based on the full projected pipeline length to the U.S. Midwest, and that the highest Arctic grade of steel would not be required for the more southern sections of the pipeline.

[102] Estimates and data from 2002 analyses supplied by member companies to AISI task force established on the Alaska Natural Gas Pipeline (provided to CRS on April 22, 2003).

[103] Ipsco, *Northern Pipelines*, pp. 12, 21.

U.S. steel industry sources expect that North American steel companies can and would make the investment, and provide the expertise necessary, to supply steel for an Alaska natural gas pipeline. President Andrew Sharkey of AISI stated in the letter cited earlier to then-Senator Frank Murkowski that "North American steel and pipe industries stand ready to work with all other interested parties to arrive at the best pipeline design necessary to accomplish the objective." He further advocated that North American steel suppliers be fully included in the design of pipeline and be given an opportunity to compete for steel procurement.[104]

The ExxonMobil High-Strength Pipeline Steel Project

An alternative type of pipe to that supplied from currently available sources has been advanced by one of the three producers of Alaska oil and gas, the ExxonMobil Corporation. It hopes to achieve substantial cost reductions by using innovative technology in building the pipeline.

In seeking to achieve such a technology breakthrough, ExxonMobil representatives on April 22, 2003, signed a letter of intent with two Japanese companies, Nippon Steel Corporation (NSC) and Mitsui & Co. Ltd., "to commercialize a jointly developed new steel, which is 20-50% stronger than alternative pipeline steels in use today. The agreement includes possible upgrades to an NSC pipe mill." The announcement also noted that the formulation for the steel had first been developed in ExxonMobil Upstream Research laboratories, and that further work to make commercial production viable has already occurred jointly with Nippon Steel.[105] The technical announcement indicated that the new steel would be rated X100 and X120, grades that hitherto have not been manufactured anywhere.[106] Press commentary on the ExxonMobil announcement stated that pipe made from the new grade of steel would be lighter in weight, and therefore easier to handle—meaning significant potential reductions in construction costs. In addition to production and long-distance pipeline interests in Alaska and the Mackenzie Delta, ExxonMobil also has interests in a Sakhalin-to-Japan gas pipeline project and the west-east pipeline project being considered to bring gas from Central Asia to China.[107]

CRS contacted ExxonMobil in August 2006 regarding further progress on the high-strength steel project. In response, a company representative replied, "Technical and developmental aspects of the X120 high-strength steel pipeline continue to be studied by ExxonMobil, and there is no new information that we can convey at this time regarding its applicability to specific projects or the timing of its commercial availability."[108]

The ExxonMobil proposal for a technologically innovative grade of steel for pipeline construction would not rely on U.S. (or Canadian) steel industry technology. The new grade of steel could be produced under license, although tooling and set-up costs would be substantial for multiple

[104] AISI letter and statement to Sen. Murkowski, April 17, 2002.

[105] ExxonMobil. "ExxonMobil Signs Letter of Intent with Nippon Steel and Mitsui & Co. Ltd. to Commercialize Advanced High Strength Steel," press release, April 22, 2003.

[106] Technical details are presented in *Proceedings of the Thirteenth (2003) International Offshore and Polar Engineering Conference*, vol. IV (2003), "Steel Development," at http://www.isope.org.

[107] *Oil Daily*, "Exxon Steel Deal Boosts ANS Gas Prospects," April 23, 2003. But there has also been speculation about the future of ExxonMobil's Sakhalin project, in view of actions taken in 2006 by the Russian government against foreign-owned operators of energy projects in the Far East region; Andrew Neff, "Death by a Thousand Cuts – Rising Resource Nationalism in Russia," presented at Global Insight World Economic Conference (Oct. 26, 2006).

[108] Email from Robert H. Davis, media adviser, ExxonMobil Corp., Aug. 18, 2006.

manufacturers working in different locations. But the required order for an Alaska natural gas pipeline may be so large as to require sharing of the work by multiple mills anyway.

Conclusion[109]

The Alaska natural gas pipeline would be a major capital investment. If, or when, it is built, the investment decision will depend on a complex set of factors that will determine its potential profitability. Those factors, on the expected revenue and cost sides, are linked to conditions in two markets: natural gas and steel. If a pipeline is to be constructed, estimates provided in this report suggest that its throughput of natural gas might equal about one third of potential U.S. future demand growth for natural gas. LNG terminals will be the primary competition for the pipeline in filling this potential demand. Should the expected demand growth fall short of projections, natural gas prices will likely decline affecting the potential profitability of both the pipeline and the LNG terminals.

On the cost side, the pipeline could generate a major steel order for the North American industry. However, the size of the pipe, as well as other required specifications, suggest that it will be expensive. Steel prices have been rising over the past several years, resulting in substantial increases in the estimated materials cost of the pipeline. Additionally, innovative production capacity to produce the required pipe might have to be constructed first particularly since no one anywhere has yet produced pipe with the dimensions and grade specified to date, further affecting the economics of the project.

The joint venture between ExxonMobil and the two Japanese steel companies appears to present an option that could spur a debate with respect to whose technology, and whose steel, would be used in this major investment project.

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