

**Regulatory Issues Report
For State of Alaska
Under the Alaska Gasline Inducement Act**



**Brown, Williams, Moorhead & Quinn, Inc.
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Introduction

The purpose of this report is to describe the findings of Brown, Williams, Moorhead & Quinn, Inc. (“BWMQ”) on important regulatory issues related to the State of Alaska’s evaluation of the AGIA application of TransCanada PipeLines Limited (“TransCanada”) to construct a natural gas pipeline system. The proposed pipeline would extend from Prudhoe Bay, Alaska through the State of Alaska to delivery points in Alberta, Canada for ultimate natural gas transportation service to the State of Alaska, Canada and the Lower-48 region of the United States.

This regulatory issues report addresses four distinct issues. The first issue is BWMQ’s evaluation of the negotiated rate practices employed on a number of United States pipeline projects, as compared to the contemplated negotiated rate structure for TransCanada’s proposed Alaskan natural gas pipeline (Section I - Negotiated Rate Study). The second issue is BWMQ’s evaluation of the rate of return on equity¹ mechanism proposed by TransCanada in its AGIA application compared to the incentive rate of return on equity mechanism authorized by the Federal Energy Regulatory Commission (“FERC”) for the original Alaska Natural Gas Transportation System (“ANGTS”) (Section II – Rate of Return Mechanism). The third issue is BWMQ’s evaluation of the natural gas supply support for the shipper contracts on major United States pipeline projects (Section III - Gas Supply Study). These supplies are compared to the known Alaskan gas supplies that are expected to be available to support an Alaskan natural gas pipeline system. And finally, the fourth issue we address is the strategic needs of TransCanada for access to Alaskan natural gas supplies to offset continued declines from its traditional sources of natural gas supply in Canada (Section IV – TransCanada’s Strategic Need for Alaskan Natural Gas Supplies for Existing TransCanada Pipeline Network).

SECTION I - NEGOTIATED RATE STUDY

Summary of Negotiated Rate Study Conclusions

TransCanada has proposed negotiated rate principles in its AGIA application that are, in most important respects, consistent with the principles employed by other major United States gas pipeline developers and the regulatory standards employed by the Federal Energy Regulatory Commission (“FERC”). TransCanada’s negotiated rate practices are consistent with other major gas pipeline developers because:

- TransCanada proposed to develop its Alaskan pipeline recourse rates under principles similar to the principles used by other pipeline developers

¹ Throughout this report references to return, rate of return, and ROE all refer to rate of return on equity.



- Prospective shippers would be offered a choice of the recourse rates or negotiated rates to be established by negotiation with TransCanada.
- The lengths of transportation contracts are subject to negotiation with shippers. Different contract lengths have been used by U.S. pipeline developers as a basis for offering different rates and terms to several categories of shippers.
- Under negotiated rate principles, TransCanada would be able to negotiate a variety of rate designs to meet the demands of the natural gas market without regulatory interference from the FERC. FERC does not investigate nor rule on the appropriateness of negotiated rates.
- TransCanada proposed an initial rate of return on equity (ROE) of 14% for its recourse rates that is consistent with the ROE approved by FERC for initial rates for many other pipeline projects.
- The AGIA application included proposals to deal with cost overrun risks and future expansions that can be viewed as an initial offer to shippers to negotiate on those important topics. Cost overrun risk adjustment provisions have been included in several negotiated transportation contracts within the industry (See Attachment No. 1).
- The ROE adjustment mechanism (periodic adjustments to ROE to reflect changes in treasury interest rates) in the AGIA application is unusual but may well be approved by FERC. While this mechanism deviates from the traditional DCF analysis approved at FERC, this is an unusual project with a unique history. FERC approved a unique Incentive Rate of Return mechanism in the original ANGTS project (which is described further below). The Incentive Rate of Return mechanism if applied today would likely be more generous than what TransCanada has applied for in its AGIA application.
- TransCanada has proposed ROE and other cost recovery provisions in its AGIA application. These adjustment mechanisms can be viewed as a potential way, after conclusion of successful negotiations, of avoiding the pipeline's need to file periodic FERC Section 4 rate cases. If properly designed, such mechanisms can keep rates paid by shippers just and reasonable and reduce regulatory costs. The inclusion of these adjustment provisions in the AGIA application and the negotiation of these adjustment mechanisms with shippers should address the twin goals of providing shippers with: 1) rate certainty over the terms of the shipper's contracts and 2) ensuring that TransCanada's Alaskan gas pipeline rates meet the regulatory standard of being just and reasonable.

Please refer to the data in Attachment 1 that shows details about the negotiated rate practices for a representative sample of pipeline projects in the United States. When the Alaskan pipeline's shipper contracts are negotiated, shippers are likely to demand and TransCanada is likely to offer provisions similar to those obtained on other U.S. pipeline projects. The shippers will have a substantial amount of bargaining power with TransCanada and will bargain from the position of knowing what has been offered and agreed to on other U. S. pipeline projects. While the exact details will be subject to negotiation, those provisions probably will include:

- Substantial discounts in negotiated rates compared to cost-based recourse rates, obtained through a rate levelization plan and a lower return on equity than is included in the recourse rate
- Contract lengths that are substantially shorter than both the gas supply life and depreciable life of the pipeline
- Provisions intended to keep the rates just and reasonable over the life of the shipper contracts, such as cost true-up, cost tracking provisions and cost overrun risk sharing provisions (True-up



provisions could be included to ensure the rates include actual debt costs, actual operating costs and actual property costs.)

- Most favored nations rate provisions that offer to similarly situated shippers rates that are as low as those offered to other shippers

Overall, the distribution of risk that occurs through the process of negotiating rates balances pipeline and shipper risks in a way that tends to benefit shippers. Pipelines must obtain a large enough capacity commitment to be able to build a pipeline of appropriate capacity and efficiency. To obtain the needed shipper commitments and economies of scale, pipeline sponsors are normally willing to take some backend risks that additional gas supplies and contract renewals will be obtained in the future to continue to underwrite the successful operation of the pipeline. Anchor shipper contract terms typically do not equal the expected depreciable life of the pipeline for new pipeline projects. Debt holders typically are only exposed to project failure over the life of the initial shipper contracts, since debt repayment periods are usually not longer than 15 years. Debt holders will verify the reasonableness of cash flows over this period of time as well as shipper credit worthiness. Thus, the equity investor in a project, such as TransCanada here, will undertake the major risk of the long-term success of a pipeline project. This risk historically has been reasonable to undertake because of the continuing need of the market place for all available gas supplies. That need is even more reasonable to undertake today given the very high level of natural gas prices in North American energy markets.

Selection of Pipeline Sample

Attachment 1 shows 24 natural gas pipeline projects that are included in BWMQ's regulatory issues report. The intent of the selection of the sample was to include major recent pipeline projects that access gas supplies from all regions of the United States and that access foreign liquefied natural gas supplies ("LNG"). A goal of the sample was to include projects that have had, where possible, producers among the shippers who contracted for capacity. The sample size was designed to be large enough to include most of the major United States pipeline project developers.²

To select pipeline projects to include in this Negotiated Rate Study, BWMQ began with our list of 24 pipeline projects. From that list 14 projects were selected for further review. A smaller list of projects was used for the Negotiated Rate Study for a variety of reasons. Importantly, data about the specific terms of negotiated rates is often not available until a project goes into service. FERC regulations permit the specific terms of the negotiated rate contracts to be kept confidential until that time.³ Attachment 1 explains other reasons for exclusion of some of the pipeline projects from the Negotiated Rate Study.

² To select appropriate projects BWMQ reviewed all of the projects listed on two recent memos prepared by Greenberg Traurig pertaining to approved capital structures and return on equity for major new or expansion projects. BWMQ also reviewed the most recent FERC reports of "Major Pipeline Projects on the Horizon", "List of Major Pending Pipeline Projects" (includes docket numbers), "List of Approved Pipeline Projects, since January 1, 2007," and a presentation slide called "Major Pipeline Expansions Jan 2007-Feb 2007." In addition to those published sources BWMQ included several major past projects from its knowledge of pipeline history and included relevant projects previously studied for the State of Alaska pertinent to the issue of identifying cost overrun risk sharing trends.

³ Terms of negotiated rate contracts, if not disclosed in a certificate application, must be disclosed either by filing the service agreement with the Commission by a project's in service date or by filing tariff sheets that disclose the essential terms of the negotiated contracts.



The Negotiated Rate Study

Overview of Current Regulatory Practice for Negotiated Prices –

At the urging of the pipeline industry, in early 1996 the FERC issued its Statement of Policy on Alternatives to Traditional Cost-of-Service Ratemaking and its companion Policy on Regulation of Negotiated Services of Natural Gas Pipelines (“1996 Policy Statement”)⁴. This pronouncement was important in influencing the development of more flexibility for market-based pricing⁵ for storage services and as a source of indirect market-responsive pricing for pipeline transportation through a price-capped rate regime.⁶

The 1996 Policy Statement introduced two new concepts pertinent to both the pricing of new gas pipeline infrastructure and in fostering markets for ongoing gas storage and transportation transactions. Under the first concept, “negotiated rates”, the pipeline and its customers by mutual agreement may deviate from normal FERC-regulated base tariff pricing. Variations from the straight-fixed variable pricing method (“SFV”)⁷ are permitted. In addition, the pipeline may propose innovative cost of service calculation methods, such as rate levelization plans⁸, or may negotiate other payment schemes such as fixed, negotiated prices over the term of a shipper’s contracts or prices that decline at defined intervals. Negotiated rates are attractive to shippers because they allow better matching of cost calculations by service period to ability to pay. For example, a rate levelization regime may benefit shippers by providing rate certainty and significantly lower initial rates than the traditional cost of service and declining rate methodology (“Traditional Rate Method”).⁹ (Indeed, some projects very likely wouldn’t have been built at all unless levelized prices were proposed.)

The second important idea in the 1996 Policy Statement was the concept of a “Recourse Rate.” As a predicate to permitting flexible, negotiated rates, the FERC required a calculation of a ceiling price to serve as a constraint on potential monopoly pricing power. Recourse rates for pipeline infrastructure

⁴ See 74 FERC ¶ 61,076 (1996).

⁵ See Order No. 678 at 115 FERC ¶ 61,343 (2006) for recent developments in the evolution of market-based pricing, especially for gas storage services, and implementation of Section 312 of the Energy Policy Act of 2005. These measures provide additional incentives for the development of storage services.

⁶ Subsequent events demonstrated that pipelines and customers did not become enamored with the other prong of the 1996 policy statement – a concept not intended for competitive markets. This idea involved sharing economic efficiencies between pipelines and their customers, a concept dubbed “incentive ratemaking.”

⁷ SFV prices mean charging fixed daily or monthly prices that include all pipeline costs, except costs that vary with throughput. Variable costs under this method are billed as gas volumes move through the pipeline system.

⁸ Rate levelization plans are intended to produce rates that remain stable throughout the terms of shipper contracts through some form of cost averaging. For example, a level rate may be calculated by changing the timing of recovery of returns on investment or by modifying the timing of recovery of depreciation. Rate levelization plans are generally developed with the intent that the net present value of each particular project is the same as under the Traditional Rate Method. The FERC has not defined a required levelization program in those instances where level rates are developed.

⁹ Under the Traditional Rate Method, prices, or rates, are calculated based on a declining rate base over the pipeline’s life. Assuming the absence of significant ongoing capital expenditures, rates under this method will tend to be the highest at the inception of service and will decline steadily thereafter. Rate base is a measure of the pipeline’s investment in its facilities and includes: gross plant investment, materials and supplies, prepayments, regulatory assets, less accumulated depreciation and amortization, accumulated deferred income taxes and regulatory liabilities.



additions have evolved generally into a price that is established under the Traditional Rate Method¹⁰. The FERC requires that such recourse rates always be offered as an alternative to negotiated prices.

The Commission ruled that costs and revenues related to negotiated services must be separately identified in pipeline records to facilitate the review of the effects of such services during general rate case proceedings. When a rate case arises, the pipeline must be prepared to assume the full risk of its negotiated services without seeking discount adjustments in establishing the billing determinant levels used to calculate prices. Cost allocations among the pipeline's various services must be calculated as though the negotiated service shippers are paying maximum recourse rates. As a result of these rules, entering into negotiated transactions exposes the pipeline to the full risk of the price used for each transaction, but with the pricing tools needed to meet market demands and the potential for improved earnings due to lighter regulation over price¹¹.

For new pipelines the Commission generally has required initial recourse reservation rates to be calculated based on billing determinants reflecting 100 percent of daily year round physical capacity, rather than contracted capacity for the project. However, FERC has permitted the costs of service underlying these rates to be calculated under methods that tend to maximize the recourse rate, such as using a relatively high rate of return on equity (i.e. the 14 percent that has been used for many projects), employing the Traditional Rate Method and depreciating the facilities over terms ranging as short as 25 years.

The Commission routinely requires the pipeline to file a rate case or cost and revenue study within three years after the pipeline goes into service to re-justify the initial rates for a new pipeline projects. This rate updating process is required both to ensure that rates remain just and reasonable and to respond to the unavoidable circumstance that initial rates for new pipelines are based on cost estimates, rather than on the costs of installed facilities. These rate updating requirements usually result in the rate of return on equity being reset to a lower level than was used within the initial rate calculations¹².

A 14% Rate of Return is Typical for Initial Recourse Rates for New Pipelines—

FERC has had a long-standing policy of granting a 14 percent return on equity for new start-up or greenfield pipelines. The reason for this is that FERC has recognized that new pipeline construction entails significant risks. A new pipeline has significant risk due to the risk factors such as complying with environmental concerns, obtaining financing, securing regulatory approval and right-of-ways, obstacles encountered during construction, the risk of acquiring shippers, and uncertainty due to the

¹⁰ To ensure that the recourse rate is not unduly restrictive, pipelines in certificate proceedings typically seek to calculate recourse rates under return and depreciation assumptions that make the negotiated price more attractive than the recourse rate. However, if the negotiated price is fixed for the contract term, it is possible that the recourse price may become lower than the negotiated price, as rate base declines over time caused by depreciation recovery.

¹¹ After considerable input and debate, the FERC concluded that negotiated flexibility would only extend to pricing and not to other terms and conditions of service. As such, negotiated rate transactions are subject to the pipeline's general tariff terms and conditions of service.

¹² For example, see Opinion No. 486 for Kern River Gas Transmission Pipeline Company where the pipeline was required to update its return on equity from 13.25% to 11.2 % in the most recently litigated general rate proceeding in Docket No. RP04-274-000. This rate case followed a 2003 Expansion project in which the pipeline essentially doubled the size of its pipeline system.



lack of an operating history. An additional risk is that of cost overruns. FERC has consistently recognized these substantial risks by approving a ROE of 14 percent for start-up, or greenfield, pipelines in certificate proceedings. As an example of FERC's long-standing policy, recently, in an order issued in 2007 concerning Sonora Pipeline LLC, 120 FERC ¶ 61,032 (2007), the pipeline asked for an ROE of 14.5 percent. FERC reduced the company proposed 14.5 percent ROE to 14% percent. In that order the FERC stated:

In the past the Commission has approved an ROE of 14 percent for new greenfield pipeline projects. Since Sonora has not provided the Commission with compelling evidence to justify a 14.5 percent ROE, the Commission will require Sonora to recalculate its rates based on a 14 percent ROE, consistent with our ROE determinations for recently approved greenfield pipelines projects.

Furthermore, in another recent order issued in 2007 involving Kinder Morgan Louisiana Pipeline LLC, 118 FERC ¶ 61,211, reh'g, 119 FERC ¶ 61,309, (2007), FERC approved a 14% ROE based on a 60/40 debt/equity ratio. In that order the FERC stated:

The commission approves KMLP's proposed 60/40 debt/equity ratios and 14 percent ROE as consistent with determinations for similar pipeline projects designed to serve LNG import terminals.

In an order issued in 2005, Dominion South Pipeline, L.P., 113 FERC 61,064(2005), FERC approved a 14% ROE based on a 50/50 debt/equity ratio. In that order the FERC stated:

Dominion South proposes to adopt the capital structure of its parent, Dominion Resources, Inc.: 50 percent debt and 50 percent common equity. Dominion South proposes a corporate interest rate of 8.10 percent as the debt cost, and a rate of return on equity of 14 percent.

We will accept Dominion South's proposed rates...

FERC has followed this policy for many years as evidenced in an order issued in 2002, Millennium Pipeline Company, L.P. 100 FERC ¶61,277 (2002). In that order, FERC stated:

Our finding here is consistent with two recent orders on major certificate projects that authorized a return on equity of 14 percent similar to that granted Millennium...

In Greenbrier Pipeline Company, LLC 101FERC ¶61,122 (2002), FERC stated:

Upon review, we find that Greenbrier's proposal to finance the instant project is consistent with other recent projects approved by the Commission... In these projects, the Commission approved a capital structure of seventy percent (70%) debt and thirty percent (30%) equity, as well as a return on equity of fourteen percent (14%). Accordingly, the Commission will approve Greenbrier's proposed capital structure and return on equity.



As demonstrated by these orders, FERC has been very consistent in granting a 14 percent return on equity to new, start-up, greenfield natural gas pipelines in certificate application proceedings. TransCanada is likely to be satisfied in negotiating contracts for the Alaskan pipeline to the extent it believes the totality of its arrangements will allow it a realistic chance to earn a reasonable rate of return on equity. The overall price of the contracts (related to the level of return on equity in the contracts) can be reduced to the extent that the contracts include negotiated features that reduce equity risks such as cost true-up and tracking provisions.

Other Typical Features of Negotiated Pipeline Projects –

The negotiated rates for typical pipeline projects are usually substantially lower than the recourse rates. This is both because the recourse rate is usually set at a high level, as described above, and because the negotiated rates are usually calculated through some form of a levelized rate design. Exceptions to this levelization rule do occur, however, reflecting the impact of competition on the rates that may be charged. To meet competition and to fill pipeline capacity at optimal design, pipelines may offer different rates to various shipper groups, such as the most favorable rates to Anchor Shippers (high capacity subscription, long term of contract or both), less favorable rates or terms to Foundation Shippers (major shippers, but smaller subscriptions) and the least favorable rates or terms to any other shippers (Standard Shippers) needed to fully subscribe the project. This sort of tiered structure for the contracts has been employed by Kinder Morgan, on their Rockies Express projects¹³. In addition, the Rockies Express project offered its shippers three rate options for each certificate segment. Shippers could choose between 1) a maximum recourse reservation rate (traditional cost of service); 2) a negotiated reservation rate (fixed rate); and 3) an adjustable negotiated reservation rate. If shippers contract under the adjustable negotiated rate option they agree to a rate adjustment mechanism to represent a “steel price adjustment” factor.

Competitive circumstances may also cause other interesting contract terms to occur, such as partial construction cost true-up mechanisms or rate of return on equity ratchet provisions to encourage and reward effective construction cost controls while allowing at least partial increases in rates if unanticipated cost overruns occur¹⁴. TransCanada’s AGIA application provides for a similar incentive

¹³ Rockies Express established three specific classes of shippers: Foundation Shippers making commitments to REX-West and REX-East (500,000 Dth/d or more), Anchor Shippers on REX-West and REX-East (200,000 to 500,000 Dth/d of capacity) and Standard Shippers. Foundation Shippers received the most beneficial negotiated reservation rates and contract rights, such as contractual rollover rights, renewable for one year terms at the same rate and quantity of service, a one-time right of refusal and MFN rights to the lowest rate. (EnCana was the only foundation shipper.) Anchor Shippers are afforded MFN rights with regards to rate as to all shippers except for Foundation Shippers, as well as annual rollover rights and the ROFR provision. Standard shippers are only offered the rollover and ROFR rights.

¹⁴ For example, on the Alliance Project the negotiated rates were computed from a base rate of return on equity of 12 percent, but provided an incentive mechanism under which each 10 percent deviation from the estimated capital costs to build the pipeline would result in a 0.5 percent inverse adjustment to the base rate of return on equity, capped at 2 percent. (This same ROE adjustment mechanism was also a feature of the Canadian portion of the project.) Alliance experienced a cost overrun so its initial negotiated rates were based on less than the 12 percent ROE base level (somewhere in the 10-11% range). The negotiated rate also uses the actual cost of debt and actual O&M expenses. The negotiated schedule of depreciation rates was designed to substantially levelize the negotiated rates over the primary terms of the transportation agreements, while providing for a recovery of an average 4 percent of annual depreciation during the same period.

For the Maritimes & Northeast Phase IV project, the negotiated rates are subject to adjustment, up or down, depending on the final construction costs reflected in two cost reports (preliminary and final) to be filed at the FERC. The adjustment will be 1 cent for each \$17 million of capital cost variance against the \$300 million cost estimate. In other words,



adjustment to return on equity if the actual capital costs of the pipeline are greater than the base capital cost (TransCanada Application at Section 2.2.3.6). Negotiated prices or contract lengths, or both, have also been impacted favorably for shippers by the presence of alternative pipeline competition. An example of these features of negotiated contracts is the contracts for subscriptions on the Gulf South East Texas to Mississippi Pipeline Project¹⁵.

Although greenfield pipeline project shippers have a choice between paying the recourse rate, or the pipeline's offered negotiated rates, shippers in almost all cases choose to sign up for negotiated rates. This is primarily due to the usually lower rates and fixed rate structure that they receive within a negotiated rate agreement.

Exceptions to this general rule have occurred, however, in at least two cases. First, for Kern River Gas Transmission Company the shippers elected to continue their existing base tariff (not negotiated) levelized rate design structure for the 2003 Expansion Project that looped almost the entire Kern River Gas Pipeline Company system. In many respects that pipeline's levelized rate structure (that pre-dated the 1996 Rate Design Policy Statement) was already very similar to having a negotiated rate; plus the shippers retained an option of being able to litigate to keep the levelized rate just and reasonable. The second exception is illustrated by the rates established for Phase II of the North Baja pipeline expansion project. The Phase II shippers elected to pay recourse rates, instead of the negotiated rates that were offered, due to the fact that the recourse rate was scheduled to be reset to a much lower level in the next rate case due to roll in of the expansion costs and billing determinants into rate design¹⁶.

Another example of customers choosing to pay either the negotiated rate option or the recourse rate option is the Transwestern Phoenix lateral project. There the agreements include two negotiated rate options under the new incremental rate schedule: (1) Prior to the inception of service, the customer may elect to pay the maximum incremental recourse rates as they may change from time to time; or (2) the customer may elect to pay the initial maximum recourse rate as a fixed rate during the contract term. The negotiated rates shown in the agreements are subject to adjustment based on construction cost variances. They will be decreased \$.001 per Dth for each \$10/ton decrease in actual steel prices, compared to a baseline steel price.

Another feature common to all of the negotiated rate agreements is that the terms of the initial contracts are for shorter periods of time than both the lives of the underlying gas supplies and depreciable lives of the pipelines. In general, negotiated rates result in lower rates to the initial shippers than cost of service recourse rate service.

A Case Study Similar to the Alaskan Pipeline –

for every 5.67% variance in capital costs, the rate is adjusted by 1.89%, or by one third of the capital cost variance (1.89% divided by 5.67%).

¹⁵ This project includes 16 contracts with the shippers paying fixed, negotiated incremental rates for the terms of their contracts. Five contracts will pay a negotiated rate averaging 16.77 cents per Dth for Louisiana delivery points with a rate range of 12 to 25 cents. Their average contract term is 6.5 years. Ten contracts will pay a negotiated rate averaging 19.72 cents per Dth for Mississippi delivery points with a range of 17 to 24.5 cents. Their average contract life is 6.6 years. One shipper's service is not identified by delivery point. That contract has a rate of 12 cents and a contract life of 6 years. (All rates are reservation rates.)

¹⁶

The Alliance Pipeline Project is an interesting example of what could occur on the Alaskan gas pipeline. The project was initially built, owned and subscribed entirely by producers. The project experienced a large construction cost overrun, so the pipeline's incentive rate of return mechanism reduced the rate of return on equity initially from 12 percent to 10 percent. Due to updating provisions in the negotiated contracts, the pipeline's negotiated contract rate as posted in its tariff now slightly exceeds the recourse rate. The negotiated rate for the Project increased from 37.4 cents as reported in the certificate order to its present level of 53.9 cents. In spite of this cost increase to shippers, the pipeline's actual earned return on equity has recovered as is shown below based on figures obtained from a Natural Gas Supply Association Study.

| 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 |
|-------|--------|--------|--------|--------|--------|--------|
| 8.95% | 15.82% | 14.40% | 15.41% | 13.17% | 12.61% | 11.85% |

For additional information on the details of the Negotiated Rate Study, please refer to Attachment 1 which summarizes important terms for the listed certificate projects.

Section II – Rate of Return Mechanism

Introduction

The purpose of this section of the BWMQ regulatory issue report is an evaluation of the rate of return on equity mechanism proposed by TransCanada in its AGIA application compared to the incentive rate of return on equity mechanism authorized by the Federal Energy Regulatory Commission (“FERC”) for the original Alaska Natural Gas Transportation System (“ANGTS”).

Summary of Conclusions for Section II – Rate of Return Mechanism

- TransCanada’s proposed rate of return on equity mechanism is less generous than the mechanism formerly approved by FERC for the ANGTS project.
- While the TransCanada ROE adjustment mechanism is unconventional due to its ongoing adjustment feature, the unique risks of an Alaskan gas pipeline project improve the chances that FERC will approve annual ROE changes tied to variations in 10-year U.S. Treasury interest rates.
- The TransCanada and ANGTS mechanisms both contain features that reasonably protect shippers against the potential risks of cost overruns and reasonably reward project sponsors and equity investors for the risks undertaken in building an Alaskan gas pipeline project.
- Even without regulatory approval, TransCanada likely can achieve the essence of its rate of return proposal with shippers through negotiated rates.
- The initial rate of return of 14% proposed by TransCanada is both reasonable in relation to the return permitted by FERC for the ANGTS and is consistent with recent regulatory precedents.

Overview

The discussion below explains the features of the ANGTS project incentive rate of return mechanism, reviews the TransCanada return mechanism proposal and contrasts and compares the features of the two mechanisms. Comments on the analysis complete the discussion.

Features of the ANGTS Incentive Rate of Return Mechanism

The incentive rate of return on equity mechanism established by FERC for ANGTS is explained in detail in the attached portion of Order No. 31 in Docket No. RM78-12 (7 FERC ¶ 61,237). The mechanism is complex, but the essential elements of the mechanism and its purposes are outlined below. The summary provided here deals only with the Alaskan portion of the mechanism; the Northern Border portion of the project had a somewhat different structure.

Rationale –

A record was developed in the ANGTS proceeding from which the President’s *Decision* was formulated. An analysis was performed of the potential for cost overruns and time delays for the selected project and comparisons were made with oil pipeline experience. From that evaluation came

various estimates of cost overruns, but the *Decision* explicitly recognized that the risk of cost overruns could be much different for an Alaskan project than Lower-48 experience. As a result, a framework was devised for an incentive rate of return mechanism (“IROR mechanism”) to encourage the minimization of cost overruns. At the same time, the IROR mechanism structure was developed to encourage equity investors to invest in the project, especially considering a perceived wider-than-normal range¹⁷ of possible construction cost outcomes that could occur on the project. The mechanism was structured to not penalize equity investors for economy-wide inflation or other non-controllable factors, such as schedule delays caused by the actions of the government. To not impede future investments in expansions in ANGTS, the mechanism provided that an incentive rate of return adjustment would be made by adjusting on a one-time basis the equity investment in rate base upward or downward, rather than by adjusting the rate of return on equity permitted on rate base.

The FERC recognized that the IROR mechanism should fit within the overall debt financing and tariff provision context of the project. For example, the order discusses the necessity of assuring debt service and that shippers can pass-through charges incurred under service agreements to their customers. An additional feature of the tariffs under the ANGTS concept was utilization of cost-of-service, rather than stated rate, tariffs. The cost-of-service approach was preferred at the time to assure that revenues available to the project companies would be adequate to meet their expenses, irrespective of fluctuations in throughput volumes or costs.¹⁸

While the IROR mechanism was in major part directed to the unique risks pertinent to project development and execution, the mechanism also reflected the financial leverage and operating realities of the Alaskan project as well. An important feature reflected in the operating phase component of the approved IROR of 14% was the financial risk of the project. The order explains that the projected equity capitalization ratio was 25 percent, in contrast to an industry average of about 50 percent at that time. Regarding business risks justifying a relatively generous operating phase return level, the order mentions the following factors as more risky than operating conditions of Lower-48 pipelines: arctic operating environment, high pressure pipeline, and high cost gas. Counter-balancing those factors somewhat were the following risk-reducing factors: cost-of-service tariff form, tracking of costs by shippers, a large reserves-to-production ratio and rolled-in pricing. Weighing all of the risk-increasing and reducing factors, the Commission concluded that the risk exposure of ANGTS investors during the operating phase of the Alaska segment of the project would be somewhat higher than the risk exposure of investors in typical Lower-48 pipeline projects, thus justifying the approved 14 percent operating phase rate of return on equity.

Components, Structure and Results of the IROR Mechanism –

The *Decision* required use of a “variable” or incentive rate of return to attempt to deter cost growth during construction. The mechanism was intended to be superior to traditional regulatory means of encouraging cost control, such as disallowance of imprudent costs, by providing economic rewards for holding down costs. A structure was established to provide these incentives comprised of the following components:

¹⁷ The wide range of possible outcomes for an Alaskan pipeline was attributed to uncertainties regarding system design and logistics of construction.

¹⁸ In that sense, the ANGTS cost-of-service tariff would have been structured to be similar to the economics of straight-fixed variable tariffs today.



1. Cost Performance Ratio – The ratio of actual final capital costs (as adjusted for inflation and scope changes) to the projected capital costs at the start of construction. A ratio higher than 1.0 indicated actual costs greater than projected or budgeted costs and a ratio of less than 1.0 indicated that actual costs are less than projected or budgeted costs. The IROR mechanism specified an allowed rate of return for a wide range of cost performance ratios.
2. Center Rate of Return – The sum of the Operation Phase Rate, the Project Risk Premium and the IROR Risk Premium. This is the rate of return allowed when actual costs (adjusted downward to remove inflation¹⁹) equal expected costs (adjusted for scope changes, such as the effects of government mandates²⁰).
3. Operation Phase Rate – The rate of return to compensate investors for the risks incurred during the operation of the pipeline after construction is complete. This return was specified by FERC to be 14%.
4. Project Risk Premium – This element was included to compensate investors for unusual risks of non-completion and other risks borne by investors during construction of the pipeline.
5. IROR Risk Premium – This was a risk premium to compensate investors for the risks created by the use of an IROR mechanism. This included risks introduced by the variability in the allowed rate of return created by the incentive mechanism.
6. Marginal Rate of Return – An analytical concept that was used to derive the IROR schedule. This was to be the rate of return implicitly allowed on incremental investment either above or below base estimates. A low marginal rate of 8% was contemplated that would permit the IROR to decline rapidly if cost increases would occur. The IROR that would have been earned on the project was to be a weighted average of the Center Rate of Return and the Marginal Rate of Return as the Cost Performance Ratio increases.
7. One Time Adjustment to Rate Base – This adjustment was to be a present value calculation that would affect the equity investment in the project recognized for regulatory purposes. The one-time adjustment was to be calculated such that the present worth of the return on equity and return of equity over the operating life of the pipeline (based on the Operation Phase Rate) is equal to the present worth of the returns from applying the IROR to the normal, unadjusted rate base.

The order discusses each of the above components of the IROR mechanism in greater detail than is necessary for our purposes here. However, it is interesting to note that the order included the table reproduced below which illustrates the results of the above concepts. The range of returns ranged between 23.44 percent if the Cost Performance Ratio were .8, to 20.35% at a ratio of 1.0, and to 12.41 percent at a cost performance ratio of 2.8. (See below) These are generous returns reflective of a then higher interest rate environment, compared to financial conditions today, and the unique risks of an Alaskan gas pipeline project.

¹⁹ This adjustment would have been a composite cost index that considered 42 indices of cost changes available at the time from the government.

²⁰ Changes in scope included four factors occurring after final project design: the effects of wars, disasters, major changes in the pipeline route ordered by Federal or state governments and major design changes compelled by changes in laws or regulations.



ANGTS INCENTIVE RATE OF RETURN

| Cost Performance Ratio | Implied ROE (%) |
|---------------------------------------|--------------------------------|
| 0.8 | 23.44 |
| 0.9 | 21.72 |
| 1.0 | 20.35 |
| 1.1 | 19.23 |
| 1.2 | 18.29 |
| 1.3 | 17.50 |
| 1.4 | 16.82 |
| 1.5 | 16.23 |
| 1.6 | 15.72 |
| 1.7 | 15.26 |
| 1.8 | 14.86 |
| 1.9 | 14.50 |
| 2.0 | 14.17 |
| 2.1 | 13.88 |
| 2.2 | 13.61 |
| 2.3 | 13.37 |
| 2.4 | 13.15 |
| 2.5 | 12.94 |
| 2.6 | 12.75 |
| 2.7 | 12.57 |
| 2.8 | 12.41 |

(See: 7 FERC 61,237 at p. 61,451)

Features of the TransCanada AGIA Rate of Return Mechanism

The rate of return on equity will be set annually at 965 basis points above the interest rate for U.S. 10-year Treasury notes in effect at the beginning of that year. TransCanada stated that according to this formula the starting rate of return would be 14%.

The rate of return on equity would also be adjusted for capital cost performance. The rate of return for both negotiated and recourse rate shippers may be adjusted downward *for the first five years* following the in service date. The reduction could be as much as 2 percent, depending on the variance between budgeted costs and actual costs. The return rate would be reduced by 5 basis points for each 1% by which actual capital costs of the pipeline exceed the base capital costs. For illustration purposes of the interest rate change adjustment feature, the following rates of return on equity would have applied if this mechanism had applied during the past ten years:

| | <u>Ten- Year Treasury</u> | <u>Premium</u> | <u>Implied ROE</u> |
|----------|-----------------------------------|----------------|------------------------|
| 1/1/2008 | 3.74% | 9.65% | 13.39% |
| 1/1/2007 | 4.76% | 9.65% | 14.41% |
| 1/1/2006 | 4.42% | 9.65% | 14.07% |
| 1/1/2005 | 4.22% | 9.65% | 13.87% |
| 1/1/2004 | 4.15% | 9.65% | 13.80% |
| 1/1/2003 | 4.05% | 9.65% | 13.70% |
| 1/1/2002 | 5.04% | 9.65% | 14.69% |
| 1/1/2001 | 5.16% | 9.65% | 14.81% |
| 1/1/2000 | 6.66% | 9.65% | 16.31% |
| 1/1/1999 | <u>4.72%</u> | <u>9.65%</u> | <u>14.37%</u> |
| Totals | <u>46.92%</u> | <u>96.50%</u> | <u>143.42%</u> |
| Average | <u>4.69%</u> | <u>9.65%</u> | <u>14.34%</u> |

Since rate of return on equity proposals cannot be validly evaluated without considering the other major features of the regulatory context, note that TransCanada proposed to structure the initial construction of the pipeline with considerable financial leverage (25% equity ratio for negotiated rate shippers and 30% for recourse rate shippers), proposed a SFV rate design, proposed to flow through certain costs (ad valorem taxes, other taxes, and operating costs) and a 25-year project life for recourse rate shippers, or up to 35 years for negotiated rate shippers.

Structuring the TransCanada proposal with a high degree of financial leverage is beneficial both to the State of Alaska, to shippers and to consumers. This benefit arises because interest financing costs are tax deductible and the cost of debt financing is less than the cost of equity financing. For these reasons, the cost of pipeline transportation would be minimized by the TransCanada proposal. This would result in maximizing the “net back” value of the market-determined gas sales revenues. As a contrast to the TransCanada gas pipeline project financing scenario, it should be noted that BP and ConocoPhillips both own oil pipelines regulated by FERC. The capital structures of those oil pipelines are very heavily weighted towards equity with only very small amounts of debt. (See Attachment No. 1D). As shown there, the average equity ratio of oil pipelines owned by ConocoPhillips is 96.25% and the average equity ratio of the oil pipelines owned by BP is 99.05%.

To help mitigate the risks and impacts of cost overruns on shippers, TransCanada proposed 100% debt borrowing for funding of any capital cost overrun. This proposal, fully detailed on pages 2.2-71 and 2.2-72 of the application, means that TransCanada would not benefit from an incremental investment opportunity that would result from a capital cost overrun. This also results in the lowest cost possible for those capital costs to shippers (absent regulatory construction cost disallowance).

Comparison of the ANGTS IROR Mechanism and TransCanada’s Proposal



Similarities –

1. The context for both proposals included similar background facts:
 - a. SFV rate design compared to Cost-of-Service rate design that ensures cost recovery regardless of throughput levels.
 - b. Very large project
 - c. Predominantly the same gas supply resources
 - d. Unique risks applicable to the Alaskan environment
 - e. Major concern regarding possible cost overrun risk
 - f. Rate recovery includes cost tracking mechanisms
 - g. Relatively low equity ratios (high debt leverage)
2. The regulatory mechanisms include provisions that are similar:
 - a. Sliding scale adjustment for cost overrun variances
 - b. Provisions to deal with cost overrun risks
 - c. Protections to shippers if cost overruns occur
 - d. Pipeline penalized for poor performance

Differences –

1. Alaskan gas costs and associated transportation fees can more readily fit into the U.S. gas price structure today than at the time of ANGTS. However, it is still true that an Alaskan project includes unique risks that don't apply to many or all Lower-48 pipelines, including: arctic environment, high operating pressure for the line, huge capital investment, daunting development schedule and reliance on one regional gas supply.
2. The ANGTS IROR mechanism potentially rewarded the pipeline for cost under runs; TransCanada proposed no return on equity reward for construction cost-reducing performance.
3. The ANGTS IROR mechanism protected the pipeline against the effects of inflationary cost increases and scope changes; TransCanada receives no rate of return adjustment protection, but that the costs of overruns are proposed to be financed by government-guaranteed debt.
4. The ANGTS IROR mechanism established an operating rate of return at a generous fixed level of 14%; TransCanada proposed that ROE will only be adjusted by underlying changes in the financial environment (changes in 10-year Treasury interest rates). This proposal subjects TransCanada to potential future review of rate of return levels if FERC does not agree to the proposed annual interest rate change triggered adjustments.
5. The ANGTS project was developed in an environment of complete regulatory review of rates; today, TransCanada can negotiate its rate arrangements with shippers as an alternative to regulation.
6. After adjusting for the change in the financial environment, the ANGTS rate of return mechanism would have been potentially much more generous to an equity investor in the Alaskan line than the proposal made by TransCanada.
7. The IROR adjustment for ANGTS would have applied over the entire life of the project through a rate base adjustment; TransCanada proposes it will receive a rate of return penalty for only five years if a cost overrun occurs.



Conclusions

TransCanada has proposed a rate of return mechanism for the Alaskan project which in total, is less generous than was granted by FERC for the ANGTS project. BWMQ believes that FERC will approve the requested return on equity of 14% as a reasonable approach, particularly in light of what FERC approved for the ANGTS project.

The TransCanada proposal is different than the ANGTS mechanism in major ways; however, it addresses similar economic and contextual issues. Of course, the means of accomplishing the objective of constructing an Alaskan gas pipeline has changed over the years because of changes in the economic environment and changes in regulatory structures.

Overall, considering the unique risks of the Alaskan gas pipeline project, TransCanada has proposed a reasonable rate of return on equity mechanism. FERC is supportive of an Alaskan gas pipeline project that will increase gas supply and provide a long-term source of gas to North American markets. FERC undoubtedly understands very well the unique risks of an Alaskan project.

The starting rate of return on equity of 14%, as proposed by TransCanada is reasonable today and is consistent with extensive regulatory precedent. See pages 5 and 6 above for a detailed discussion of recently certificated pipeline projects that received 14% return on equity at FERC.

Section III - Gas Supply Analysis

Introduction

The purpose of this section of the BWMQ regulatory issue report is an evaluation of the natural gas supply support for the existing shipper contracts on major United States pipeline projects (“Gas Supply Study”). These supplies are compared to the known Alaskan gas supplies that are expected to be available to support an Alaskan natural gas pipeline system.

Summary of Conclusions for Section III – Gas Supply Analysis

A frequently quoted total for proven gas supply reserves in Alaska is 35 Tcf. BWMQ calculated that the gas supply requirements for a 35-year period for the Alaskan pipeline will be 57.5 Tcf. Based on the current gas supply estimates of the Potential Gas Committee, the combination of proven reserves of 35 Tcf and estimated potential resources of 59.2 Tcf, or a total of 94.2 Tcf, will be more than adequate to fill the Alaskan gas pipeline.

BWMQ computed reserve life and reserve/resource life indices²¹ for 19 of the 24 U.S. projects studied²². The gas supply analysis table presented in Attachment 2 to this report shows that the average reserve life index for the 19 U.S. projects studied averaged 11.3 years, whereas the average for the reserve/resource life index was 43.5 years. Comparable figures for the North Slope Alaska gas reserves are a reserve life index of 19.3 years and a reserve/resource life index of 55.4 years. Thus, the evidence today indicates that gas supplies available to support an Alaskan natural gas pipeline are actually greater than the gas supplies available to support typical Lower-48 pipeline projects.

Many Lower-48 project proponents are taking significant risks on gas supplies and on expected renewal of shipper contracts. Attachment 2 summarizes the contract lives for the various projects that were studied. Typical shipper contract lengths have been from 10 to 15 years (range 5 to 30 years) while book depreciable lives for the projects averaged 34.3 years (range 25 to 60 years). TransCanada’s AGIA pipeline proposal falls within these ranges.

Selection of Pipeline Project Sample

Attachment 2 shows 24 natural gas pipeline projects that were included in an earlier section of this report. The intent of the selection of the sample was to include major recent pipeline projects that access gas supplies from all regions of the United States and that access foreign liquefied natural gas supplies (“LNG”). A goal of the sample was to include projects that have had, where possible,

²¹ The reserve life index and reserve/resource life index are indices and not profiles of the life in years of a particular supply source, but are useful for comparison purposes. The reserve life index represents the number of years to exhaust proved reserves assuming production remains constant throughout the life of the gas supply. The reserve/resource life index also assumes constant production and represents the quotient of the sum of the proved reserves and the potential resources.

²² Five of the projects in the sample were LNG projects that rely on world natural gas supplies which can be considered to have productive lives at least as long as United States supplies.

producers among the shippers who contracted for capacity. The sample size was designed to be large enough to include most of the major United States pipeline project developers.²³

Natural Gas Supply Support for the Shipper Contracts of Major United States Natural Gas Pipeline Projects

Contents:

- Background, Summary and History
- Reserve Risk for New Pipeline Projects
- Definition of Reserves and Resources
- Shipper Reserves by Petroleum Province
- Survey of New Built Pipeline Projects

Background & Summary --

The relationship between new pipeline projects and the initial natural gas reserve quantities has changed dramatically since the early 1980's and FERC initial regulatory reforms beginning with Order 436. Today most natural gas pipeline projects are financed and built long before the related gas supply is fully proven and developed. This is in direct contrast to the situation that existed in the period from the 1950's to the early 1980s, when pipeline projects were financed and constructed based upon a 20-year natural gas supply resource base. Today many pipelines are being constructed even though proved reserves can only provide throughput for 10 years or less. However, proved reserves are only one element needed to support a pipeline project in today's environment. Commitments from anchor shippers that see future potential natural gas resources of various degrees of certainty are critical components for pipeline project success. Potential reserves may add many more years to proven reserve throughput given the changing economics of today's exploration and production. Industry participants are unlikely to explore, drill and develop reserves when a pipeline interconnection may be many years off. While the wellhead price is an important factor in exploratory and development drilling activity, the availability of an exporting pipeline from a gas supply region is just as important.

History-

Pipeline companies historically have always carefully evaluated the economic viability of gas-production-resource pipelines. Some such pipeline projects were large, others more modest; all are less than the proposed Alaskan Gas Pipeline.

In the 1950s, 1960s and early 1970s, interstate pipelines purchased and transported natural gas from supply sources to market under a 20-year reserve life standard instituted by the Federal Power Commission. As the reserve life index (proved reserves divided by current production) gradually

²³ To select appropriate projects BWMQ reviewed all of the projects listed on two recent memos prepared by Greenberg Traurig pertaining to approved capital structures and return on equity for major new or expansion projects. BWMQ also reviewed the most recent FERC reports of "Major Pipeline Projects on the Horizon", "List of Major Pending Pipeline Projects" (includes docket numbers), "List of Approved Pipeline Projects, since January 1, 2007," and a presentation slide called "Major Pipeline Expansions Jan 2007-Feb 2007." In addition to those published sources BWMQ included several major past projects from its knowledge of pipeline history and included relevant projects previously studied for the State of Alaska pertinent to the issue of identifying cost overrun risk sharing trends.



decreased due to the increasing demand for gas along with producers seeking greater production of proven reserves, the Commission relaxed the 20-year rule.

Since that time, the Commission has occasionally expressed concern with adequate gas reserve support, but has issued Certificates of Public Convenience and Necessity based upon less than a 20-year reserve life showing to numerous natural gas pipeline companies (see Attachment 2).

Reserve Risk for New Projects –

Almost all new supply to market area pipeline projects involved supply areas which already contain export natural gas pipelines. Examples of incremental natural gas pipelines are:

| New Pipeline | Supply Area | Existing Pipelines |
|---|---------------------------------|---|
| Alliance Rockies Express Kern River | WCSB Northern Rocky Mountain | TransCanada Mainline System Colorado Interstate Trailblazer Northwest Pipeline |
| Trailblazer/WIC | Northern Rocky Mountain | Questar Northwest Pipeline Colorado Interstate |
| Kern River | Northern Rocky Mountain | Questar Northwest Pipeline Colorado Interstate Southern Star Central |

In each case above and other similar projects, the project pipeline first evaluated the potential project internally and then employed independent evaluations concerning gas supply among other issues. In each evaluation, available proven reserves were compiled along with an analysis of the potential for growth in reserves along with potential new field discoveries. In some cases, the evaluation is included in the Statement H, Gas Supply to the application for a certificate from FERC. In other cases, a simple summary of the reserves and potential resources is provided. In no case was there ever provided a highly detailed and sophisticated gas supply study.

Pipeline companies normally evaluate proved gas reserves which are, or will be shut-in that can be immediately connected. They then turn to the analysis and estimates of potential resources such as those available from an industry source, such as the Potential Gas Committee (PGC).

The highly regarded PGC is made up of industry analysts from producers and pipeline companies. Their estimates involve the evaluation of the growth in existing reserves and the potential for new field discoveries. Their estimates are region specific and employ state-of-the-art methods. The PGC in its Report, Potential Supply of Natural Gas in the United States, November 2007, states:

“The estimates of the Potential Gas Committee(PGC) represent potential natural gas resources expected that, in the judgment of its members, can be recovered by future drilling under conditions of:

1. adequate economic incentives in terms of price/cost relationships, and
2. current or foreseeable technology.”



PGC estimates for the Alaska North Slope and Northern Rocky Mountain area are shown in Figure 1. The potential estimates are shown alongside proved reserves.

Figure 1

Proved Reserves and Potential Resources

| | <i>As of 2006</i> | | | |
|-------------------------------------|-------------------|---------------------|------------|--------|
| | Proved Reserves | Potential Resources | | |
| | | Growth in Reserves | New Fields | Total |
| | Tcf | Tcf | Tcf | Tcf |
| Alaska North Slope | 35 | 32.2 | 27 | 59.2 |
| Northern Rocky Mountain Area | 45.7 | 58.89 | 71.39 | 130.28 |

Potential Resources: Potential Gas Committee 2007
 Proved Reserves: North Slope - DOE/NETL-200/12797
 Proved Reserves: Northern Rocky Mountain Area - Energy Information Administration 2007

The PGC estimates of potential resources (growth in existing reserves and new fields) in the Alaska North Slope can be compared to those estimates listed in NETL's assessment for the following areas: Colville-Canning and state waters, Beaufort Sea OCS, NPRA and ANWR.

PGC-- 59.2 Tcf
 NETL Assessment-- 85.3 Tcf (Table 2.21 of NETL's August 7, 2007 Report)

Both of these estimates are economically recoverable gas additions that are expected to be found and developed.

Definition of Proved Reserves and Undiscovered Resources –

Proved reserves are the most assured estimate of recoverable natural gas. They are based upon geological and geophysical analysis, electric logs, core analysis and production tests. Undiscovered resources are based upon the analysis of undrilled prospects. They range from probable resources which are considered to be the growth in proved reserves all the way to rank wildcat drilling prospects, the least assured of estimates.

Shipper Reserves by Petroleum Province –

Two examples are relevant to illustrate the relationship between the supporting supply for a pipeline project. Both are natural gas pipelines that were constructed to attach a specific supply area.



They were the original pipelines to connect to an isolated supply area. In this regard, they are analogous, yet on a small scale, to an Alaskan Gas Pipeline.

High Island Offshore System (HIOS)

The first is the HIOS (High Island Offshore System) system. HIOS transports gas from the southeast offshore Texas area. This offshore production area had its own specific geological setting. The pipeline planning stage began in the early 1970s when a few gas discoveries were made in addition to heavy leasing in nearby areas by major producers. Once the initial gas discoveries were delineated and proved reserves established by geological, geophysical, well log analysis and production tests, the planning stage moved to seeking a certificate with FPC to construct and operate a connecting pipeline. Transcontinental Gas Pipeline Corporation, ANR Pipeline Company and one or two other small partners proceeded to seek a certificate with the FPC (now FERC) and construct the pipeline. The initial proven reserves would provide for the use of the pipeline capacity for only 5 years. The knowledge of additional undeveloped discoveries, the evaluation of specific undrilled leased prospects and the evaluation of potential for future resources that may become proved future reserves assured the pipeline partners that they could go forward with the project and they successfully obtained financing for the project.

Currently, since the first flows of gas through the HIOS system began, throughput is now in decline. Yet, HIOS has been in operation for 30 years plus and is considered a successful pipeline project. HIOS was constructed on the basis of 5 years of proven reserves but once the pipeline was operational, additional offshore discoveries and development was successful and eventually extended the economic and depreciable life of HIOS to at least 40 years.

Sable Island Offshore Energy Project

The second pipeline project supported by a single oil and gas province is the Sable Offshore Energy Project. Natural gas was discovered on the Scotian Shelf in 1967. A great deal of caution in building a pipeline was the result of slowed exploration and less than stellar results of drilling. However, a pipeline was planned, authorized by the Canadian authorities and constructed based upon already proven reserves, unconfirmed gas discoveries, potential resources both within the shelf and in deepwater.

Currently, long term flows through the pipeline system from the initial discoveries will provide capacity flows for only 5 years from 2007. Gas began to flow into the pipeline in 2000 with proved reserves that would provide approximately 8 years of pipeline capacity throughput. Additional later discoveries, presently under development, will add 4 years. The deepwater potential has been evaluated, yet is presently unsuccessful. The pipeline project itself is now considered somewhat less than originally expected, nevertheless, due to the construction of the pipeline, the proven gas reserves are not stranded.

The two examples above demonstrate the stimulus effect that a pipeline has on the development of gas reserves. The circumstance in Alaska should be similar. A new gas pipeline should result in producers engaging in new drilling to prove up the extent of the reserves on their leases and also new

exploratory drilling. In the case of Alaska, however, the anticipated initial capacity of the pipeline is expected to be largely committed to move the known gas reserves from the North Slope. In both the HIOS and Sable Island cases the reserves that were commercialized after the lines went into service did not require major expansions and the mere construction of a pipeline was adequate to promote new drilling.

In order for a similar stimulus to occur in Alaska it will be critical that the gas pipeline be expandable to accommodate significant new Alaskan discoveries if they occur. Including the proper incentives for pipeline expansion in TransCanada's approved AGIA application will enhance the probability that future pipeline expansions will occur.

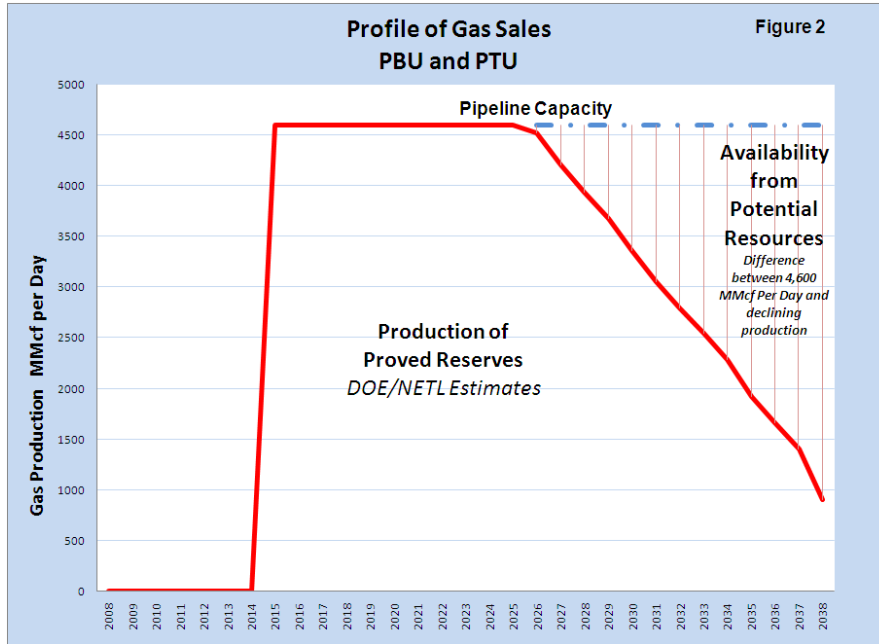
Alaskan North Slope Pipeline Project

In order to keep the proposed pipeline full at 4.5 Bcf per day for 35 years, it will require 57.5 Tcf of North Slope gas. This amounts to 22 Tcf more than the combined proved reserves in the producing oil fields and Point Thomson Unit. This must be translated into recoverable reserves and future resources discoveries. For 35 years of capacity throughput, it would require proved reserves far greater than 57.5 Tcf, because gas production eventually declines for each vintage of proved reserves. Thus reserves of approximately 70 to 80 Tcf would eventually be required to effectuate the delivery of 4.5 Bcf per day for 35 years. Therefore, additional gas resources must be found and developed.

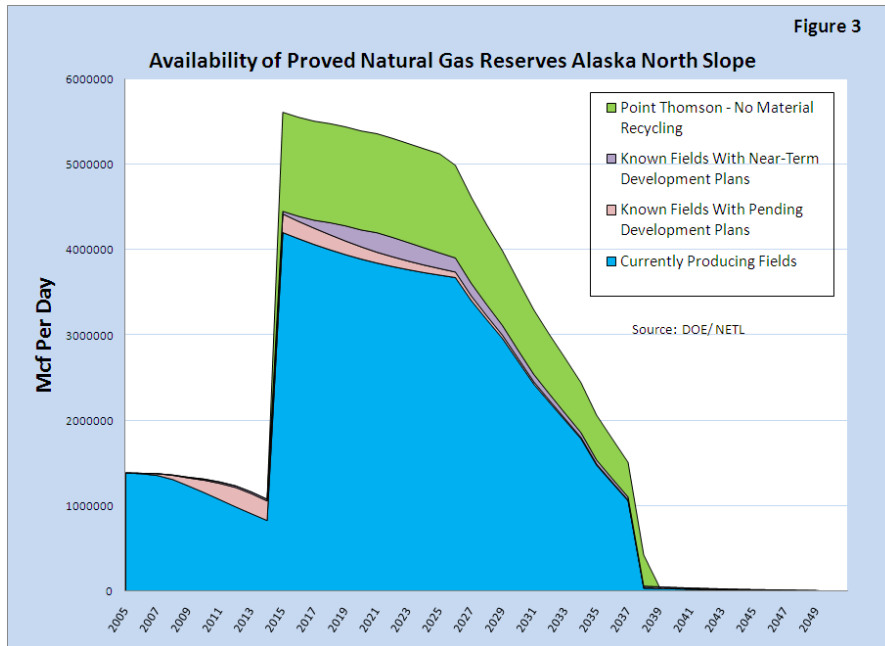
The frequently quoted estimate for all of the North Slope recoverable reserves is 35 Tcf. The two fields, Prudhoe Bay Unit (PBU) and the Point Thompson Unit (PTU) are estimated to contain 23.7 Tcf and 8.0 Tcf of recoverable reserves, respectively. Other fields, Lisburne, Duck Island, Northstar, Colville River and Milne Point, make up the difference between the estimated 35 Tcf of total recoverable reserves in the North Slope and 31.7 Tcf (PBU and PTU). These fields currently may supply some sales gas, however, they are dependent upon construction of natural gas gathering systems for full development of these reserves.

According to the current estimates published by the Department of Energy's National Energy Technology Laboratory (NETL), the recoverable reserves of the PBU can supply 3.44 Bcf per day for 12 years and the PTU can supply 1.16 Bcf per day for 11 years. The total equates to the proposed pipeline capacity of 4.5 Bcf per day. After 12 years, the gas availability will decline, by about 10% per year. This is shown in Figure 2.

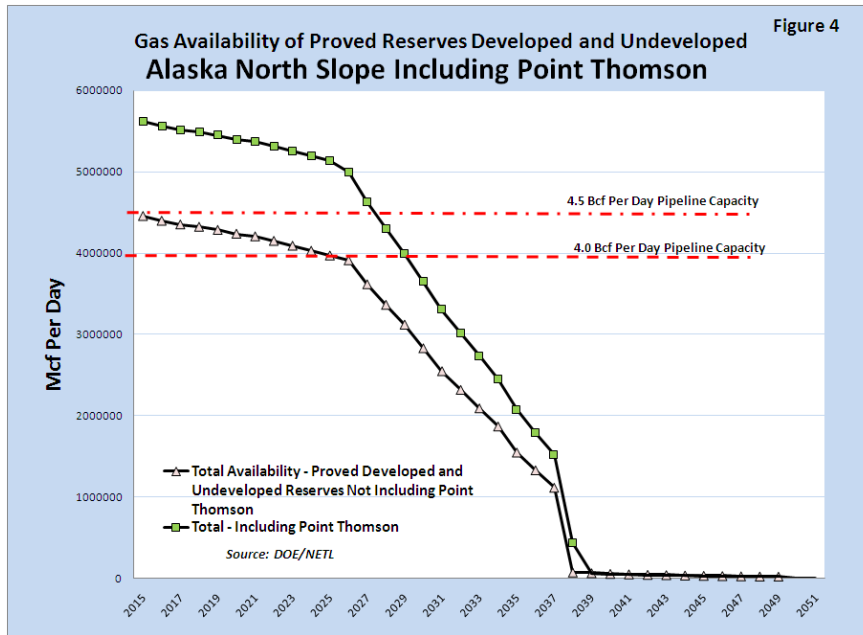




The following graphs (Figures 3 and 4) breakout the gas production from the Prudhoe Bay Unit and the Point Thomson Unit and also includes the production from the smaller gas accumulations of other oil fields in the ANS. These fields, in some cases will require gas gathering facilities. It is assumed that such gas gathering will be compensatory. The inclusion of Point Thomson assumes major natural gas production for sale at inception (i.e. no material, if any cycling).



The following graph (Figure 4) shows two gas availability profiles, the square boxed line shows Alaska North Slope production with full natural gas production from Point Thomson and the triangle line shows Alaskan North Slope production assuming no natural gas production from Point Thomson.



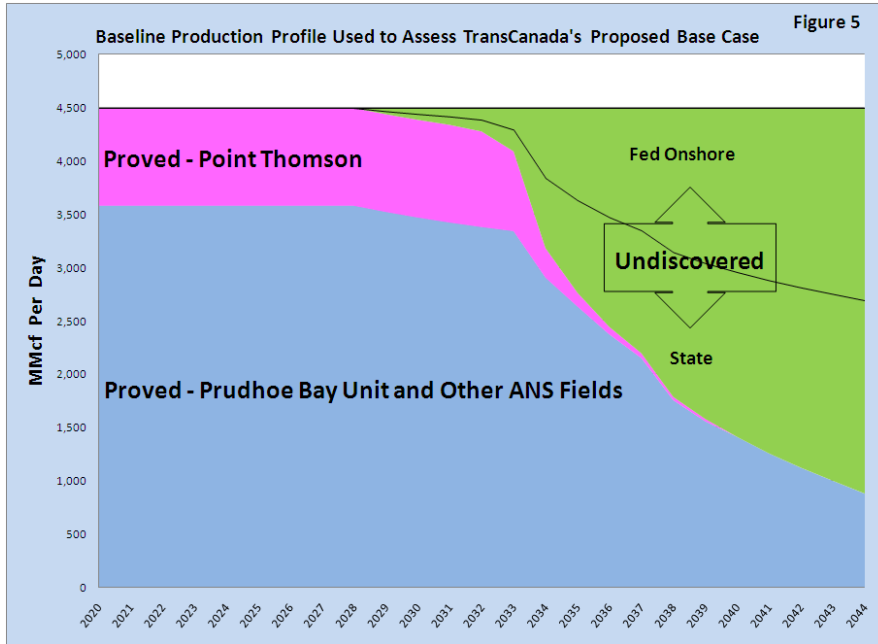
In order to provide an additional 23 years of gas available at 4.5 Bcf per day, exploratory drilling must take place to establish new fields and growth in the reserves of existing fields.

For the North Slope, the PGC estimates potential resources (over and above) proved reserves to be as follows:

| Growth in Existing Reserves | New Fields | Total Potential |
|-----------------------------|------------|-----------------|
| 32.2 Tcf | 27.0 Tcf | 59.2 Tcf |

If, for example 57 Tcf of gas is needed to support gas availability of 4.5 Bcf per day, the combination (94.2 Tcf) of proved reserves of 35 Tcf and estimated potential resources of 59.2 Tcf will be more than adequate.

Similarly, estimates made for the DNR by Black and Veatch and Parroted, showing the baseline production profile used to assess the TransCanada base case is shown below in Figure 5. This estimate was made using the reservoir modeling of Petrotel, along with the employment of various data found in the NETL DOE report.



The above estimates in Figures 2, 3, 4 and 5 will be adequate support for the current FERC gas supply standards for issuance of a Certificate of Public Convenience and Necessity.

Shippers are generally made up of marketers, LDCs, industrial customers and the gas producers themselves. Only the gas producers know the amount of proved reserves and may have some estimates of reserve growth and a rough, yet uncertain idea of potential new future discoveries. Marketers, LDCs and industrial customers have little, if any, knowledge concerning the level of reserves of natural gas supporting the contract quantity and term.

Further, as demonstrated earlier, a term of 10 or 20 years, for example, if supported not by 10 or 20 years of proved reserves in the ground, may be supported by some level of proved reserves and estimates of potential future gas supply connections. In such cases, potential estimates of an entire oil and gas province ranks as support for a pipeline project. Examples of such pipeline projects that rely upon potential resources for an entire producing region, in addition to some proved reserve commitments, are as follows:

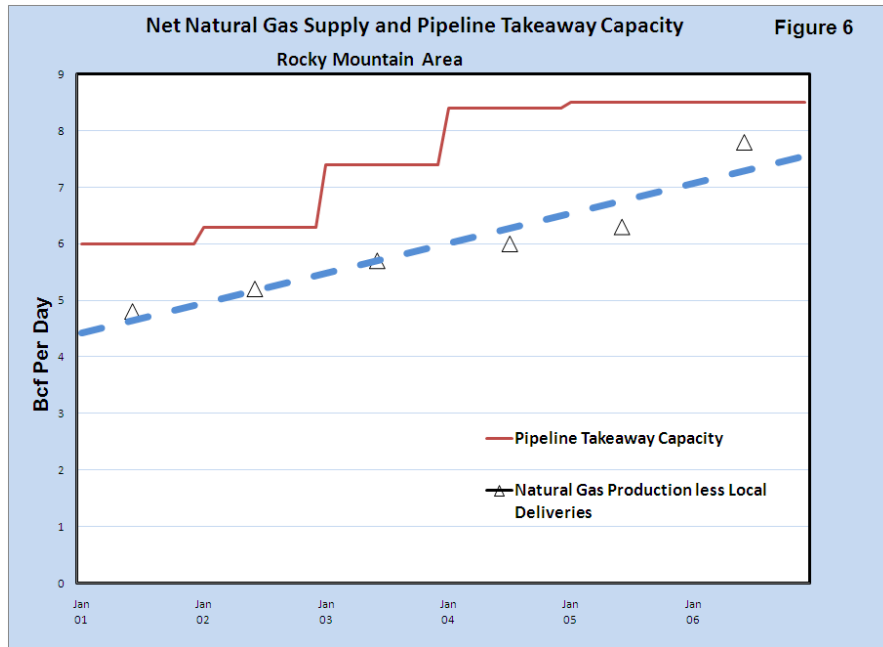
For the Rocky Mountain Area (See Figure 1) –

| <u>Project</u> | <u>Contract Length</u> |
|-----------------------------------|------------------------|
| • Cheyenne Plains | 10-15 |
| • Rockies Express | 10-15 |
| • Kern River Initial Construction | 15 |

For the Western Canada Sedimentary Basin –

| | |
|-------------------------|-------|
| • Alliance | 15 |
| • PGT Expansion Project | 15-30 |

Figure 6 shows how pipeline companies in the Rocky Mountain area have kept a consistent pace between constructed capacity and the amount of gas available for transport out of the region. This figure also shows that some gas which was considered an undiscovered resource in 2001 is being transported through pipelines in 2006.



A more comprehensive list of projects along with their contract terms and other salient facts is shown in Attachment 2, Gas Supply Analysis and Attachment 1, Survey of New Built Pipeline Projects.

Proved reserves in the entire Northern Rocky Mountain area (Colorado, Utah and Wyoming) as of the end of 2006 could sustain current deliveries of 3.4 Tcf per year for less than 13 years. For the WCSB, the number of years is less than 9.3 years. Note that proved reserves in the Alaska North Slope could maintain production of 4.5 Bcf per day for 11 to 12 years.

Survey of New Built Pipeline Projects –

A study of major gas pipeline projects supported by gas supply was performed. It includes 24 recent pipeline projects and lists each project with its description, cost, capacity, in-service date, major customers, contract lengths and book depreciation life. In all cases there is no definitive proved reserve life associated with the particular project. Supply studies supporting each project were either not included in Applicants certificate filing or were based upon proved reserves and a discussion of the availability of potential resources. This gas supply study is shown in Attachment 2.

In summary, in the past 30 years, new projects planned and proposed by natural gas pipeline companies, either to connect to new supply areas or existing supply areas based upon necessary potential resources, have been constructed and presently in operation. The only newly constructed



pipeline to connect a single source that did not perform according to initial plans (however, it yet may) is the Offshore Sable Island Energy system.

Additional details about the pipelines selected for the Gas supply study are contained in the Excel file that summarizes the study.

Section IV – TransCanada’s Strategic Need for Alaskan Natural Gas Supplies for Existing TransCanada Pipeline Network

Introduction

The purpose of this section of the BWMQ regulatory issue report is an evaluation of TransCanada’s strategic needs for the Alaskan Natural Gas Supply.

Summary of Conclusions for Section IV – TransCanada’s Strategic Need for Alaskan Natural Gas Supplies

As a preliminary comment, TransCanada over the past 10 years has invested heavily in North American pipelines, particularly U.S. natural gas pipeline assets. It has proposed business and regulatory practices for its AGIA Alaskan gas pipeline project that are generally consistent with the business and regulatory practices employed by TransCanada within its United States pipeline operations. And those regulatory practices are not materially different than the practices used by other gas pipeline developers.

TransCanada’s “opening offer” in its AGIA application can be expected to be sweetened to be consistent with its behavior on its other pipelines in the United States. As examples, the provisions in its future negotiated contracts can be expected to include a lower return on equity, and contract lengths that are significantly shorter than expected gas supply life and expected depreciation life. For further information on this topic please refer to Section I, Negotiated Rate Study report.

TransCanada has been very active in acquiring and consolidating its position as one of the largest holders of U.S. gas pipeline assets, and the largest pipeline capacity holder in North America. Given the projected gas production decline in the Western Canadian Sedimentary Basin (WCSB) and the dependency of many of TransCanada’s U.S. gas pipelines on gas imports from TransCanada pipeline facilities, the long-term strategic interests of TransCanada are now deeply woven together with a successful AGIA pipeline application that would provide a secure long-term source of additional gas supply to offset production declines in the WCSB. BWMQ believes that TransCanada recognizes that their long-term strategic interests are best served by ensuring the approval and construction of their AGIA pipeline proposal. This should also provide the proper incentives and flexibility for TransCanada to negotiate a pipeline project that works for the benefit of all the participating parties to ensure a viable project.

TransCanada’s Current Holdings in United States Natural Gas Pipelines

The following chart shows TransCanada’s current holding in U.S. natural gas pipelines and storage companies:

| <u>Pipeline Company Name</u> | <u>Effective Ownership Percentage</u> |
|-------------------------------------|--|
| ANR Pipeline Company | 100.00% |



| | |
|--|---------|
| ANR Storage Company | 100.00% |
| Blue Lake Gas Storage Company | 75.00% |
| Gas Transmission Northwest Corporation | 100.00% |
| Great Lakes Gas Transmission, L.P. | 68.50% |
| Iroquois Gas Transmission System, L.P. | 44.50% |
| North Baja Pipeline, LLC | 100.00% |
| Northern Border Pipeline Company | 16.10% |
| Portland Natural Gas Transmission System | 61.71% |
| Tuscarora Gas Transmission System | 32.10% |

The specific detailed information about the ownership of these systems was verified by reference to TransCanada's annual report to stockholders, SEC filings and the FERC Form No. 2s for each of the systems.

Canada's National Energy Board Energy Market Assessment November 2007

Canada's National Energy Board (NEB) periodically issues its detailed assessment of future energy supply and demand conditions in Canada. The latest assessment shows continued decline in the future natural gas supply availability from the Western Canadian Supply Basin (WCSB). The NEB assessment under its Continuing Trends scenario predicts that increasing demand for natural gas use from oil sands production and electricity generation, with declining supply from the WCSB, will reduce the natural gas available for export to the United States to zero by 2028. The NEB report states that Canada's annual production of 17.1 Bcf/d in 2005 is expected to decline by 40% to 10.5 Bcf/d by the end of 2030.

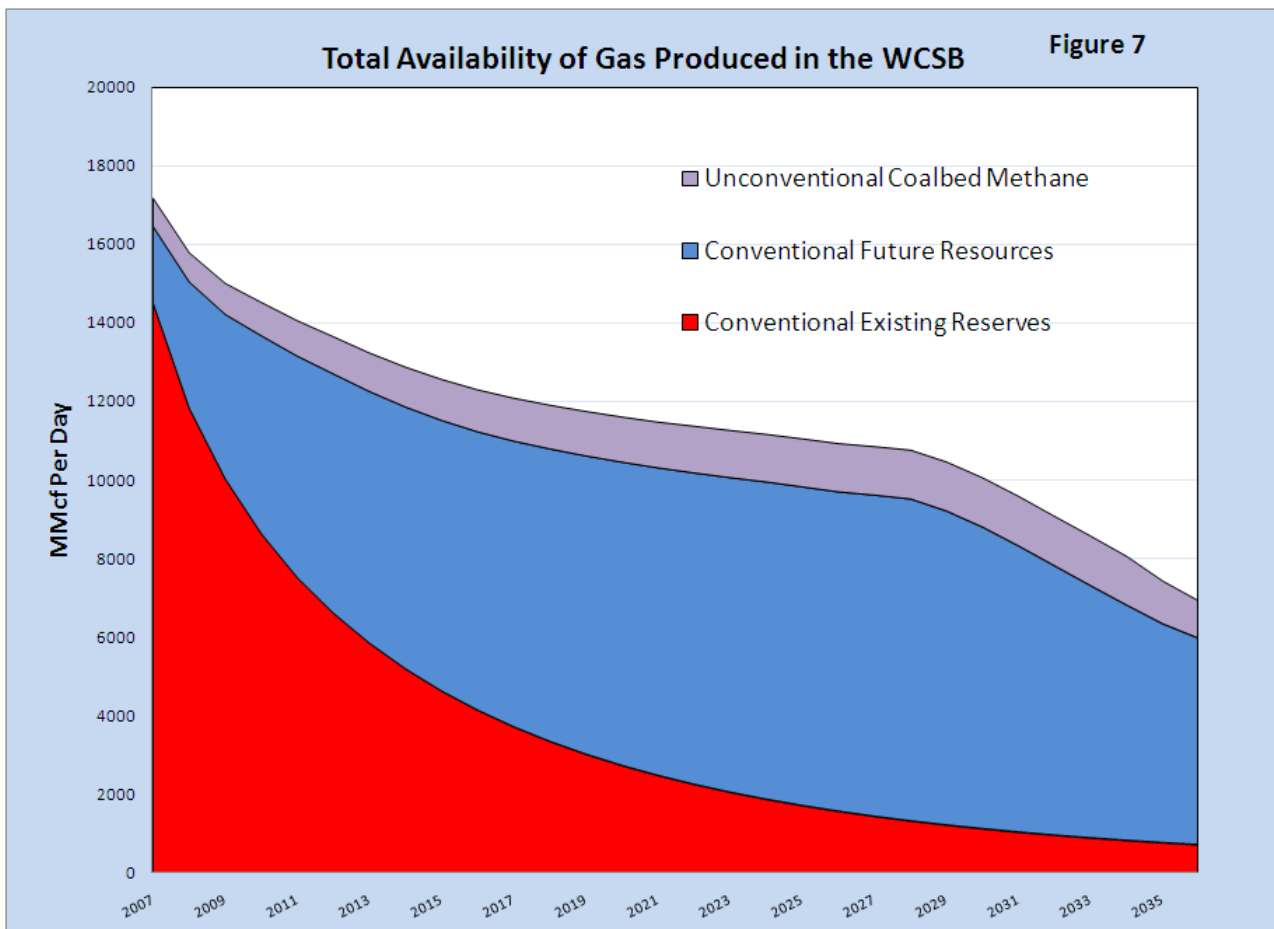
The NEB also issues a periodic transportation assessment of Canadian Hydrocarbon Transportation capacity. The latest assessment issued in July 2007 shows that TransCanada averaged 1.4 Bcf/d of excess capacity over the past four year period (2003 to 2007). This excess capacity provided the impetus for TransCanada to propose the transfer of its Line 100-1 from natural gas transportation service to oil pipeline service (TransCanada Keystone Project) to move increasing supplies of tar sand/syncrude production from the WCSB to markets. The TransCanada mainline has capacity of slightly less than 8 Bcf/d, and exports to the United States have accounted for approximately 50% of total deliveries as recently as 2004. TransCanada's Foothills pipeline is the next largest natural gas pipeline in Canada with a capacity of approximately 2.4 Bcf/d. Alliance Pipeline is TransCanada's largest competitor with a capacity of approximately 1.4 Bcf/d.

Oil sands production in the WCSB is expected to increase substantially in the future, particularly with the dramatic increase in world crude oil prices. Many of the tar sand/syncrude projects use natural gas to process the heavy oil for production and to upgrade the syncrude to marketable crude oil quality. Recent forecasts expect natural gas usage by the tar sands/syncrude industry to increase from 2 Bcf/d to 6 Bcf/d. TransCanada's website has a report titled Western Canada Summer 2008 Supply & Demand Outlook that predicts a major decline in exports this summer caused by increasing oil sands demand, and storage demand combined with a decline in supply from the WCSB. The report also shows that gas well drilling in the WCSB has declined 16% compared to last year with gas well connection down 29% to date due to a large decline in drilling last year. This has occurred even though natural gas prices are stronger than ever and testing record highs in North America. The primary reason for a decline in



WCSB gas production has been the continuing decline in the finding rate for new natural gas reserves and a continuing decline in the rate of gas well productivity. The TransCanada Summer Outlook concludes by showing a decline of production from the WCSB of 600-700 MMcf/d this summer, with throughput on the TransCanada Alberta system declining to 10.4-10.7 Bcf/d this summer compared to 11.2 Bcf/d last summer. Finally, the Outlook predicts Western Canada exports are expected to decline by about 1 Bcf/d this summer due to higher intra-WCSB demand and lower natural gas availability.

BWMQ forecasts the available natural gas supply from the WCSB based on the NEB's Continuing Trends scenario. This forecast shows a significant and non-transitory decline from the WCSB for the foreseeable future. BWMQ's latest gas supply forecast is shown in Figure 7 below.



TransCanada's website includes a Management Discussion and Analysis Overview that discusses the long-term need for additional supplies of natural gas from non-traditional sources such as the Mackenzie Delta and Alaska. The Overview specifically mentions pipeline risk factors associated with the decline in the productivity of the WCSB. The WCSB had remaining discovered reserves of

approximately 57 trillion cubic feet and a reserves-to-production ratio of approximately nine years. TransCanada cautions that gas supply is expected to decline due to continued reduction in levels of drilling activity in the WCSB, caused by lower prices, higher supply costs, which include higher royalty payments, and the stronger Canadian dollar. TransCanada anticipates there will be excess natural gas pipeline capacity out of the WCSB in the foreseeable future, as a result of pipeline expansion over the past decade on its pipelines, competition from other pipelines, and significant growth in natural gas demand in Alberta driven by oil sands projects and electricity generation requirements.

Many of TransCanada's U.S. pipeline assets have historically been supplied by natural gas produced from the WCSB, these include: Northern Border, GTN, PNGTS, Iroquois, Great Lakes, and Tuscarora. A continued decline in natural gas availability from the WCSB and higher prices for natural gas supplies from the WCSB, will increase earnings concerns on these pipelines as throughput and a decline in long-term firm contract commitments intensify. This is also true for TransCanada's mainline facilities and the Foothills Pipeline system. It is clear from our earlier discussion that the single most important business and strategic concern facing TransCanada's natural gas pipeline assets is access to significant new gas supply sources. An Alaskan natural gas pipeline project is vital to TransCanada's long-term financial success. The construction of TransCanada's proposed Alaskan natural gas pipeline project will give its existing pipeline infrastructure, the Foothills system and the TransCanada mainline system access to critical additional natural gas supplies to offset continuing future declines from the WCSB. Additional throughput from Alaska that will flow into the TransCanada and Foothills pipeline systems, with exports to its existing U.S. pipeline assets, will address TransCanada's most pressing long-term financial need – how to keep its existing pipeline assets fully utilized. TransCanada has a tremendous investment in its existing pipeline infrastructure in the U.S. and Canada. Net earnings on its pipeline business were \$686 million in 2007. For TransCanada to fully utilize its investment in its pipeline assets and infrastructure it requires access to a significant new source of natural gas supplies and an Alaskan natural gas pipeline is the best single source for those supplies.



Study of Major Gas Pipeline Certificate Projects Summary of Recourse and Negotiated Rates

| <u>Project Number</u> | <u>Project Name</u> | <u>\$ Millions Capital Cost</u> | <u>Return on Equity</u> | <u>Recourse Rate</u> | <u>Negotiated Rates</u> | <u>Customers, Including Producers</u> | <u>Contract Lengths Years</u> | <u>Book Depreciation Life</u> | |
|-----------------------|--|---------------------------------|---|----------------------|---|--|---|-------------------------------|----------|
| 1 | Cheyenne Plains | 331.8 | 14.00% | \$ | 0.3525 | \$.28 to \$.34 Anadarko 100,000 Dth BP Energy 40,000 Dth ConocoPhillips 30,000 Dth | 10 to 15 | 35 years | |
| 2 | Rockies Express-West | 1,609.4 | 13.00% | \$ | 0.2325 for Phase I and II \$.9067 for Phase I and II plus Overthrust facilities | \$.184 to \$.204 Conoco/Phillips 400,000 Dth BP Energy 100,000 Dth (See Appendix A to the Order at 116 FERC ¶61,272 for complete list) | 10 to 15 | 35 years | |
| 3 | Alliance Pipeline | 1,340.0 | 12.0% (c) | \$ | 0.4197 | \$ 0.3743 17 shippers and 15 producers were part of the project sponsorship group. | 15 | 25 years | |
| 4 | Maritimes & Northeast Phase IV Project | 321.3 | 14.25% | \$ | 0.7804 | \$ 0.5300 (subject to adjustment based on the facility costs incurred) | Repsol Energy North America Corp. | 15 | 42 years |
| 5 | Phoenix Pipeline Project and San Juan 2008 Expansion | 660.1 | 14.00% | \$ | \$.8957 from San Juan and \$.8257 from East Thoreau points | \$ 0.5500 Salt River Arizona Public Service UNGS Gas Southwest Gas Gila River Power | 15 years, Except for 25,000 per day with 4 year contract | 35 years | |
| 6 | Gulf South East Texas to Mississippi Expansion | 776.9 | 12.25% | \$ | 0.2581 | \$.12 to \$.245 Project has 12 shippers. | 5 to 15 years | 25 years | |
| 7 | Southeast Supply Header | 842.0 | 13.50% | \$ | 0.3827 | Not yet available Customres are: Florida Power & Light 500 MMcfd Progress Energy 200 MMcfd Southern Co. Services 175 MMcfd EOG Resources 50 MMcfd Tampa Electric 20 MMcfd | 5 to 14 years | 60 years | |
| 8 | Creole Trail Pipeline | 578.9 | 14.00% | \$ | 0.1462 | Not yet available Not available | Not Available | 40 years | |
| 9 | Northeast Gateway | 179.7 | 11.33% | \$ | 0.1428 | \$.0727 to \$.1147 Affiliate - Excelerate Energy Limited Partnership | 25 | 25 years | |
| 10 | Carthage to Perryville Project | 403.5 | 6.47% weighted return from RP94-343 | \$ | Sought to roll in this project into existing rates | \$.1463 to \$.2441 Not disclosed in applications - 8 shippers The anchor shipper was a producer - 600 Dth/d. | 4 to 10 years | 44 years | |
| 11 | Gulfstream | 1,654.0 | 14.00% | \$ | 0.6620 to 0.9641 (hourly rates) | \$.55 to \$.5950 Prior to initiating service the project obtained 10 binding precedent agreements to serve customers in Florida; the project remained partly unsubscribed for a substantial period of time. | 15 to 20 years | 40 years | |
| 12 | Vector Pipeline | 447.0 | 11.50% (with construction cost adjustment mechanism) | \$ | 0.3130 | \$ 0.2210 Had precedent agreements with four shippers for 828.3 MDth/d of capacity; two were affiliates of the owners and subscribed for 700,000 MDth/d. | 20 years (based on levelization term) | 25 years | |
| 13 | North Baja Expansion Project | 290.9 | 14.00% (continued from initial rate) | \$ | Existing base tariff rate 0.1321 (estimated rolled-in rate in next rate case) \$.0558 (FERC approved roll-in of this project) | Recourse rate, negotiated rate or a combination Coral Energy Resources Sempra Energy LNG Some pre-existing shippers Chevron Imperial Irrigation District | 20 years | 30 years | |
| 14 | Guardian Pipeline | 277.2 | 14.00% | \$ | 0.1533 | \$ 0.1230 Wisconsin Gas, Alliant Energy, WPS Energy Services and one additional shipper | 10 years | 30 years | |

Study of Major Gas Pipeline Certificate Projects Summary of Recourse and Negotiated Rates Selection Group 1-13

| <u>Project Number</u> | <u>Project Sponsor</u> | <u>Project Name</u> | <u>Projected or Actual In Service Date</u> | <u>Gas Supply Study</u> | <u>Negotiated Rates Study</u> | <u>TransCanada Affiliate</u> |
|-----------------------|---|---|---|-------------------------|-------------------------------|------------------------------|
| 1 | El Paso (CIG and Cheyenne Plains) | Cheyenne Plains | Aug-05 | X | X | |
| 2 | Sempra and Kinder Morgan | Rockies Express-West | Feb-08 | X | X | |
| 3 | Alliance Pipeline L.P. (Initially 17 limited partners) | Alliance Pipeline | Dec-00 | X | X | |
| 4 | Maritimes & Northeast Pipeline, LLC | Phase IV Project | Nov-08 | X | X | |
| 5 | Transwestern Pipeline Company, LLC | Phoenix Pipeline Project and San Juan 2008 Expansion | May-08 | X | X | |
| 6 | Loews Corp., general partner of Boardwalk Pipeline Partners, LP through Gulf South Pipeline Company, LP | East Texas to Mississippi Expansion Project | Jan-08 | X | X | |
| 7 | Kinder Morgan Sempra ConocoPhillips | Rockies Express-East REX Northeast Express (future) | Near End of 2008 to <u>Clarington, Ohio</u> Final Project Dec-10 | X | Not in service | |
| 8 | Kinder Morgan Energy Partners Energy Transfer Partners | Kinder Morgan's Midcontinent Express | 2-2009 for <u>Phase I</u> Phase II to be installed within 5 years thereafter | X | Not in service | |
| 9 | Spectra Energy CenterPoint Energy Southern Natural | Southeast Supply Header Project (Spectra, Centerpoint and Southern Natural) | 6/1/2008 | X | X | |
| 10 | Kinder Morgan Energy Partners | Kinder Morgan Louisiana Pipeline | Leg 1 by 10-1-2008 Leg 2 by 4-1-2009 | X | Not in service | |
| 11 | Chinere Trail Pipeline , LP (Owned by Cheniere Energy, Inc.) | Cheniere's Creole Trail Pipeline | Apr-08 | X | X | |

Study of Major Gas Pipeline Certificate Projects Summary of Recourse and Negotiated Rates Selection Group 12-24

| <u>Project Number</u> | <u>Project Sponsor</u> | <u>Project Name</u> | <u>Projected or Actual In Service Date</u> | <u>Gas Supply Study</u> | <u>Negotiated Rates Study</u> | <u>TransCanada Affiliate</u> |
|-----------------------|--|--|--|-------------------------|---|------------------------------|
| 12 | Maritimes & Northeast Pipeline, LLC | Maritimes & Northeast Sable Offshore Energy Project | 11/1/1999 | X | Small system | |
| 13 | Algonquin Gas Transmission, LLC Spectra Energy Notheast Gateway Energy Bridge, LLC | Algonquin's Northeast Gateway Project | Dec-07 | X | X | |
| 14 | Centerpoint Energy Gas Transmission (CenterPoint Energy, Inc.) | Centerpoint Carthage to Perryville Project | May-07 Phase 3 2nd Quarter 2008 | X | X | |
| 15 | The Williams Companies/Tenneco (Kern River Gas Transmission Company) | Kern River Initial Construction | Feb-92 | X | Not negotiated | |
| 16 | MidAmerican Energy/The Williams Companies | Kern River Expansion Completed in 2003 | May-03 | X | Not negotiated | |
| 17 | Columbia, KeySpan Corp., DTE Energy | Millenium Pipeline | 11/1/2007 | X | Under construction | |
| 18 | CMS Gas Transmission and Storage co., Viking Gas Transmission, and WICOR, Inc. | Guardian Pipeline | 11/1/2007 | X | X | |
| 19 | ANR Gulfstream, Coastal Southern Pipeline Company (Spectra Energy and Williams own the pipeline now) | Gulfstream | May-02 | X | X | |
| 20 | Vector Pipeline L.P. Enbridge Inc. (59.6%) and DTE Energy Company (39.4%) are the current owners. | Vector Pipeline | 12/1/2000 | X | X | |
| 21 | Texas Gas Transmission, LLC | Texas Gas Transmission Fayetteville/Greenville Expansion | 8/1/2008 | X | Not in service | |
| 22 | Boardwalk Pipeline Partners, LP Gulf Crossing Pipeline Company, LLC and Gulf South Pipeline Company, LP | Gulf Crossing Project | 10/1/2008 | X | Not in service | |
| 23 | Pacific Gas & Electric Pacific Gas Transmission | PGT Expansion Project 1992/1993 | 11/1/1993 | X | Prior to negotiated rate policy statement | X |
| 24 | North Baja Pipeline, LLC | North Baja Expansion Project | 4/3/2008 6/1/2009 1/1/2010 | X | X | X |



**Analysis of the Capital Structures of
the Oil Pipelines Owned by BP and Conoco Phillips**
(FERC Regulated - Data Source 2007 FERC Form No. 6)

Oil Pipeline Investments of BP:

| <u>Company Name</u> | <u>Ownership Interest</u> | <u>Capital Structure</u> | | <u>Capital Amounts</u> | | |
|-----------------------------------|-------------------------------|--------------------------|---------------|------------------------|---------------|--------------|
| | | <u>Debt</u> | <u>Equity</u> | <u>\$000s</u> | | |
| | | | | <u>Debt</u> | <u>Equity</u> | <u>Total</u> |
| Amoco Capline Pipeline Company | 100.00% | | 100.00% | | 8,813 | 8,813 |
| Black Lake Pipeline Company | 50.00% | | 100.00% | | 21,714 | 21,714 |
| BP Oil Pipeline Company | 100.00% | | 100.00% | | 598,226 | 598,226 |
| BP Pipelines (Alaska) Inc. | 100.00% | | 100.00% | | 480,093 | 480,093 |
| BP Pipelines (North America) Inc. | 100.00% | 0.97% | 99.03% | 29,740 | 3,027,497 | 3,057,237 |
| BP Transportation (Alaska) Inc. | 100.00% | | 100.00% | | 268,666 | 268,666 |
| Chicap Pipe Line Company | 29.17% | | 100.00% | | 10,503 | 10,503 |
| Cypress Pipe Line Company | 50.00% | | 100.00% | | 11,204 | 11,204 |
| Dixie Pipeline Company | 25.82% | 27.13% | 72.87% | 10,000 | 26,853 | 36,853 |
| Endicott Pipeline Company | 67.94% | | 100.00% | | 1,540 | 1,540 |
| Inland Corporation | 46.80% | | 100.00% | | 7,193 | 7,193 |
| Kuparak Transportation Company | 38.00% | | 100.00% | | 30,468 | 30,468 |
| Mars Oil Pipeline Company | 28.50% | | 100.00% | | 121,924 | 121,924 |
| Mid-Valley Pipeline Company | 50.00% | | 100.00% | | 24,239 | 24,239 |
| Milne Point Pipeline | 100.00% | | 100.00% | | 30,100 | 30,100 |
| Olympic Pipe Line Company | 35.00% | 49.81% | 50.19% | 67,500 | 68,023 | 135,523 |
| West Texas Gulf Pipeline Company | 16.51% | | 100.00% | | 15,189 | 15,189 |
| Wilprise Pipeline Company | 25.30% | | 100.00% | | 18,653 | 18,653 |
| Average Equity Ratio | | | | | <u>99.05%</u> | |

Oil Pipeline Investments of ConocoPhillips:

| <u>Company Name</u> | <u>Ownership Interest</u> | <u>Capital Structure</u> | | <u>Capital Amounts</u> | | |
|---|-------------------------------|--------------------------|---------------|------------------------|---------------|--------------|
| | | <u>Debt</u> | <u>Equity</u> | <u>\$000s</u> | | |
| | | | | <u>Debt</u> | <u>Equity</u> | <u>Total</u> |
| Chisholm Pipeline Company | 50.00% | | 100.00% | | 5,051 | 5,051 |
| Colonial Pipeline Company | 8.53% | 114.42% | -14.42% | 1,300,446 | (163,901) | 1,136,545 |
| Conoco Offshore Pipe Line Company | 100.00% | | 100.00% | | 5,185 | 5,185 |
| ConocoPhillips Pipe Line Company | 100.00% | | 100.00% | | 1,420,964 | 1,420,964 |
| ConocoPhillips Transportation Alaska Inc. | 100.00% | 66.89% | 33.11% | 282,500 | 139,852 | 422,352 |
| Explorer Pipeline Company | 7.71% | 99.76% | 0.24% | 484,572 | 1,148 | 485,720 |
| Heartland Pipeline Company | 50.00% | | 100.00% | | 12,018 | 12,018 |
| Phillips Texas Pipeline Company | 100.00% | | 100.00% | | 327,558 | 327,558 |
| Pioneer Pipe Line Company | 50.01% | 54.16% | 45.84% | 38,017 | 32,178 | 70,195 |
| Seaway Crude Pipeline Company | 50.00% | | 100.00% | | 261,619 | 261,619 |
| Seaway Products Pipeline Company | 100.00% | | 100.00% | | 56,032 | 56,032 |
| WestTex66 Pipeline Company | 100.00% | | 100.00% | | 197,919 | 197,919 |
| Yellowstone Pipe Line Company | 46.00% | | 100.00% | | 30,031 | 30,031 |
| Average Equity Ratio | | | | | <u>96.25%</u> | |



**Study of Major Gas Pipeline Projects
Support for Projects - Reserves and Contracts
Gas Supply Analysis**

| Project Name | Contract Lengths Years | Book Depreciation Life - Years | Supply Area | Year Project In Service | Bcf Area-Wide Reserves 2006 | Bcf Area-Wide Resources 2006 | Bcf Current Production 2006 | Reserve Life Index | Reserves / Resources Life Index | Average RLI | Average RRLI |
|--|--|--------------------------------|---------------------------|-------------------------|-----------------------------|------------------------------|-----------------------------|--------------------|---------------------------------|-------------|--------------|
| Cheyenne Plains | 10 to 15 | 35 | Rocky Mtn | 2005 | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 14.25 | 54.99 |
| Rockies Express-West | 10 to 15 | 35 | Rocky Mtn | 2008 | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 14.25 | 54.99 |
| Alliance Pipeline | 15 | 25 | WCSB | 2000 | 57,000 | 137,000 | 6,022 | 9.47 | 32.22 | 9.47 | 32.22 |
| Phase IV Project | 15 | 42 | LNG | 2008 | | | | | | | |
| Phoenix Pipeline Project and San Juan 2008 Expansion | 15 years, Except for 25,000 per day with 4 year contract | 35 | San Juan Basin | 2008 | 31,169 | 25,998 | 2,120 | 14.70 | 26.97 | 14.70 | 26.97 |
| East Texas to Mississippi Expansion Project | 5 to 15 years | 25 | Midcontinent Gulf Coast | 2008 | 15,305 | 41,700 | 1,181 | 12.96 | 48.27 | 12.96 | 48.27 |
| Rockies Express-East REX Northeast Express (future) | commitments expected by 4-1-2008 | 35 | Rocky Mtn | 2009 | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 14.25 | 54.99 |
| Midcontinent Express | likely 10 to 15 year | 33 | Midcontinent | 2009 | 47,064 | 108,820 | 3,681 | 12.79 | 42.35 | 12.79 | 42.35 |
| Southeast Supply Header | 5 to 14 years | 60 | Louisiana/Miss Gulf Coast | 2008 | 7,528 31,839 | 16,360 50,645 | 635 5,539 | 11.86 5.75 | 37.62 14.89 | 8.80 | 26.26 |
| Kinder Morgan Louisiana Pipeline | | 33 | LNG | 2009 | | | | | | | |
| Chinere Trail Pipeline | | 40 | LNG | 2008 | | | | | | | |
| Sable Offshore Energy Project | 20 | 25 | Offshore Nova Scotia | 2000 | 538 | 3,000 | 142 | 3.79 | 24.92 | 3.79 | 24.92 |
| Northeast Gateway | 25 | 25 | LNG | 2008 | | | | | | | |
| Carthage to Perryville Project | 4 to 10 years | 44 | NE Texas/NoLa | 2008 | 22,020 | 58,060 | 1,733 | 12.71 | 46.21 | 12.71 | 46.21 |
| Kern River Initial Construction | 15 years | 25 | Rocky Mtn | 1992 | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 14.25 | 54.99 |
| Kern River Expansion completed in 2003 | 10 and 15 years | 50 | Rocky Mtn | 2003 | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 14.25 | 54.99 |
| Millenium Pipeline | 10 years | 30 | WCSB | 2008 | 57,000 | 137,000 | 6,022 | 9.47 | 32.22 | 9.47 | 32.22 |

**Study of Major Gas Pipeline Projects
Support for Projects - Reserves and Contracts
Gas Supply Analysis**

| Project Name | Contract Lengths Years | Book Depreciation Life - Years | Supply Area | Year Project In Service | Bcf Area-Wide Reserves 2006 | Bcf Area-Wide Resources 2006 | Bcf Current Production 2006 | Reserve Life Index | Reserves / Resources Life Index | Average RLI | Average RRLI |
|-----------------------------------|--|--------------------------------|--------------|-------------------------|-----------------------------|------------------------------|-----------------------------|--------------------|---------------------------------|---------------|---------------|
| Guardian Pipeline | 10 years | 30 | Chicago Hub | 2008 | | | | | | | |
| | | | Rocky Mtn | | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 10.56 | 36.11 |
| | | | WCSB | | 57,000 | 137,000 | 6,022 | 9.47 | 32.22 | | |
| | | | Midcontinent | | 47,064 | 108,820 | 3,681 | 12.79 | 42.35 | | |
| | | | Gulf Coast | | 31,839 | 50,645 | 5,539 | 5.75 | 14.89 | | |
| Gulfstream | 15 to 20 years | 40 | Gulf Coast | 2002 | 31,839 | 50,645 | 5,539 | 5.75 | 14.89 | 5.75 | 14.89 |
| Vector Pipeline | 20 years (based on levelization term) | 25 | Rocky Mtn | 2001 | | | | | | | |
| | | | WCSB | | 45,844 | 131,099 | 3,218 | 14.25 | 54.99 | 10.56 | 36.11 |
| | | | Midcontinent | | 57,000 | 137,000 | 6,022 | 9.47 | 32.22 | | |
| | | | Gulf Coast | | 47,064 | 108,820 | 3,681 | 12.79 | 42.35 | | |
| | | | Gulf Coast | | 31,839 | 50,645 | 5,539 | 5.75 | 14.89 | | |
| Fayetteville/Greenville Expansion | 10 years | 35 | NW Arkansas | 2009 | 2,269 | 34,028 | 188 | 12.07 | 193.07 | 8.91 | 103.98 |
| | | | Gulf Coast | | 31,839 | 50,645 | 5,539 | 5.75 | 14.89 | | |
| Gulf Crossing Project | 5 to 10 years | 35 | NE Texas | 2009 | 15,305 | 41,700 | 1,181 | 12.96 | 48.27 | 12.96 | 48.27 |
| PGT Expansion Project 1992/1993 | 15 to 30 years | 30 | WCSB | 1994 | 57,000 | 137,000 | 6,022 | 9.47 | 32.22 | 9.47 | 32.22 |
| North Baja | 20 years | 30 | LNG | 2008-2010 | | | | | | | |
| Totals | | <u>822</u> | | | | | | | Total | <u>214.11</u> | <u>825.90</u> |
| Average | | <u>34.25</u> | | | | | | | Average for 19 | <u>11.27</u> | <u>43.47</u> |

Note: The reserve life index and reserve/resource life index are considered indices and as such are not accurate profiles of the life in years of a particular supply source. They are useful for comparison purposes. The production divisor employed herein are at 2006 as well as the proved reserve and resource components. The reserve life index represents the number of years to exhaust the proved reserves assuming the production component remains constant throughout the life of the supply. The reserve/resource life index also assumes constant production. This index represents the quotient of the sum of the proved reserves and the potential resources. Care must be taken in interpreting the results of the reserve/resource life index as production reaches a point where it declines and resource discoveries do not take place at a single point in time.

North Slope Alaska gas reserve life and reserve/resource life index on a comparative basis with the above Lower 48 indexes is as follows:

$$\text{Reserve Life Index - ANS} = 31.7 / (4.5)(365) = 19.3$$

$$\text{Reserve/Resource Life Index - ANS} = (31.7 + 59.2) / (4.5)(365) = 55.4$$

Proved reserve source; Energy Information Administration
Potential gas resources; Potential Gas Committee, 2006

Note: LNG projects rely on the availability of world gas supply resources. As such it was not considered necessary to determine data comparable to United States for this analysis.