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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

Regulatory Law Chambers *is a Calgary-based boutique law firm dedicated to excellence in energy regulatory matters. We have expertise in oil and gas, electricity, including renewable energies and commercial matters, tolls and tariff, compliance and environmental related matters. We frequently represent clients in proceedings before the Alberta Energy Regulator ("AER"), the Alberta Utilities Commission ("AUC"), the National Energy Board ("NEB"), all levels of the Courts, and in energy related arbitrations and mediations.* ***Our advice is practical and strategic. Our advocacy is effective.***

This monthly report summarizes matters under the jurisdiction of the AER, the AUC and the NEB and proceedings resulting from AER, AUC and NEB decisions. For further information, please contact Rosa Twyman at Rosa.Twyman@RLChambers.ca or Vincent Light at Vincent.Light@RLChambers.ca.

IN THIS ISSUE:

SUPREME COURT OF CANADA

Jessica Ernst v Alberta Energy Regulator (2015 CanLII 23001) (April 30, 2014)
Leave to Appeal

The Supreme Court of Canada ("SCC") granted Jessica Ernst leave to appeal the judgment of the Alberta Court of Appeal ("ABCA") in *Ernst v Alberta (Energy Resources Conservation Board)*, 2014 ABCA 285. In the decision on which the SCC has now granted leave, the ABCA dismissed Jessica Ernst's claims on the following issues:

(a) Do the pleadings disclose a private law duty of care on the Energy Resources Conservation Board?

(b) Does s. 43 of the *Energy Resources Conservation Act* ("*ERCA*") bar a claim for negligent omissions?

(c) Can s. 43 of the *ERCA* bar a Charter of Rights and Freedoms claim?

S. 43 of the ERCA states as follows:

> No action or proceeding may be brought against the Board or a member of the Board or a person referred to in section 10 or 17(1) in respect of any act or thing done purportedly in pursuance of this Act, or any Act that the Board administers, the regulations under any of those Acts or a decision, order or direction of the Board.

(This section was repealed and replaced by s. 27 of the *Responsible Energy Development Act*.)

As is standard practice, the SCC did not provide its reasons for granting the leave application.

ALBERTA ENERGY REGULATOR

Change in Business Process Relating to the Review of Upstream Oil and Gas Reclamation Certificate Applications (Bulletin 2015-04)
Bulletin – Change in Business Process

Noting several common major and minor deficiencies in applications for upstream oil and gas reclamation certificate applications, the AER announced that, effective immediately, the following business processes will apply:

(a) If an application contains no more than two minor deficiencies, the applicants will be notified by letter and have ten days to correct the deficiencies;

(b) The application will otherwise be refused, and the applicants notified if any of the following apply:

  (i) The application contains one major deficiency;

  (ii) The application contains three or more minor deficiencies; or

  (iii) The applicant has not responded to a letter requesting correction of two or fewer minor deficiencies within ten days.

The AER clarified that the application requirements themselves have not changed under the 2010 Reclamation Criteria for Wellsites and Associated Facilities: Application Guidelines.

ALBERTA UTILITIES COMMISSION

Distribution Performance-Based Regulation Commission-initiated Proceeding to Consider Modifications to the Minimum Filing Requirements for Capital Tracker Applications (Decision 3558-D01-2015)
Capital Tracker – Filing Requirements

The AUC initiated a proceeding to review the filing requirements for capital tracker applications. This was due to varying positions from parties in the 2013 capital tracker true-up and 2014-2015 forecast capital tracker proceedings (the "Previous Proceedings") respecting the level of information required in a capital tracker application.

Parties' submissions in the Previous Proceedings diverged on whether companies should be required to show the accounting test calculations for:

(a) All capital addition projects or programs undertaken in a particular year; or

(b) For only those capital addition projects or programs for which the companies applied for capital tracker treatment.

In Decision 2012-237, the AUC had approved the use of capital tracker mechanisms as part of the performance based-regulation ("PBR") plans, applying the following criteria to determine whether capital tracker treatment is warranted:

(a) The project must be outside the normal course of the company's ongoing operations;

(b) Ordinarily, the project must be for replacement of existing capital assets, or undertaking the project must be required by an external party; and

(c) The project must have a material effect on the company's finances.

<u>Issues</u>

The AUC requested submissions from AltaGas Utilities Inc. ("AltaGas"), ATCO Electric Ltd. ("ATCO Electric"), ATCO Gas and Pipelines Ltd. ("ATCO Gas"), EPCOR Distribution & Transmission Inc. ("EPCOR") and FortisAlberta Inc. ("FAI") (collectively, the "Companies") on the following issues:

(a) Should the Companies be required to provide an accounting test and all assumptions in Excel format with linked and working formulas, for all capital addition projects or programs including those capital addition projects or programs for which the companies have not applied for capital tracker treatment ("Issue 1")?

(b) Should the Companies be required to provide descriptions of the types of capital, including capital projects or programs, for which the companies have not applied for capital tracker treatment ("Issue 2")?

(c) Are other changes required to the minimum filing requirements for capital trackers provided in Section 10.2 of Decision 2013-435 ("Issue 3")?

<u>Issue 1</u>

With respect to Issue 1, the AUC held that accounting tests should only apply to capital tracker projects or programs. Therefore, the AUC held that the Companies are not required to put forward accounting test results for capital addition projects and programs that are not put forward for capital tracker treatment. The AUC also determined that the inclusion of such information was not necessary to determine whether the capital tracker projects and programs have been properly grouped.

In spite of these findings, the AUC did find that there was some merit in obtaining additional information with respect to non-capital tracker amounts to improve understanding of cost allocations between capital tracker and non-capital tracker amounts. Accordingly, the AUC directed the Companies to provide details of any new or changed cost allocation methodologies impacting the allocations of actual or forecast depreciation, tax, and overhead amounts allocated to each project or program in Excel format. This requirement was added to the minimum filing requirements for capital tracker applications.

<u>Issue 2</u>

With respect to Issue 2, the AUC held that a short description setting out the nature, scope and timing of non-capital tracker projects and programs would assist in understanding the groupings of capital tracker projects and programs by allowing direct comparisons between capital tracker and non-capital tracker programs. This requirement was added to the minimum filing requirements for capital tracker applications. The AUC noted that such short descriptions would not likely be onerous, and may cut down on the need for additional information requests throughout the course of future capital tracker proceedings.

<u>Issue 3</u>

With respect to Issue 3, the Consumers' Coalition of Alberta ("CCA") and the Office of the Utilities Consumer Advocate ("UCA") submitted several proposed additions to the minimum filing requirements, arguing that none would be onerous or contrary to the intent of the minimum filing requirements. Among these changes, was a proposal by the CCA to require a company to file its overhead and tax allocation policy, a description of how the policies were applied, and calculations for all capital projects. The CCA also proposed that each company provide a reconciliation of tax, return and depreciation from the accounting test calculations to the amounts in each respective company's general ledger.

The AUC rejected the CCA and UCA's proposed changes to overhead, tax and depreciation information, citing its previous determinations on Issue 1, whereby it found that providing additional information had merit, but noted that such additional information, in the context of the UCA and CCA's requests, were not required to satisfy the test for capital tracker treatment.

The CCA also requested that the inclusion of a table showing the cost of a standard project followed by the cost drivers or components for extra items would assist in assessing projects for capital tracker purposes. ATCO, FAI and EPCOR opposed the CCA's request, noting variously that the provision of such information was either not possible due to estimation tools and methods used, or that each company's respective approach differs to such a degree that standardization was not appropriate and would add a regulatory burden.

The AUC agreed with ATCO, FAI, and EPCOR, finding that it does not prescribe a single approach. However, the AUC noted that the onus remains on the applicant in a capital tracker proceeding to present the information in such a manner that will assist in an assessment of the prudency of actual expenditures, and the reasonableness of forecast expenditures.

The CCA also proposed that the Companies include disclosure of affiliate transactions to overhead or other services which are included in capital tracker costs. The AUC held that there was merit to separate identification of any affiliate related costs included in the actual or forecast costs of capital tracker projects or programs. The AUC ordered the Companies to include a summary of such services in its business cases filed with subsequent capital tracker applications.

ENMAX, ATCO and AltaGas took the position that clarification was necessary for multi-year programs approved for capital tracker treatment under the minimum filing requirements. Notably, ATCO argued that once AUC approval is given for a multi-year program, unless there is a significant change, a company should not be required to provide more information demonstrating the prudency or need for the program in subsequent applications. The AUC held that a clarification was necessary for multi-year projects, citing its previous determinations on the same point for multi-year projects in Decision 2014-373. This requirement was therefore clarified in the minimum filing requirements for capital tracker applications.

<u>Decision</u>

The AUC therefore ordered the Companies to incorporate the findings and revised minimum filing requirements as set out in this decision into their future capital tracker applications.

1646658 Alberta Ltd. Alteration to Bull Creek Wind Project (Decision 3520-D01-2015)
Wind Project – Amendment

1646658 Alberta Ltd., a wholly-owned subsidiary of BluEarth Renewables Inc. ("BluEarth") applied to alter its approval to construct and operate the Bull Creek Wind Project (the "Project"). BluEarth had previously received approval to construct and operate the Project, which at the time consisted of 46 wind turbines, operating at a total nameplate capacity of 115-megawatts, and the Bull Creek 280S Substation. BluEarth applied to reduce the size of the Project to reflect the generation needed to fulfill contracted power purchase agreements and to change to a distribution level interconnection, as the Bull Creek 280S Substation was no longer required (the "Amended Project").

The Amended Project would consist of 17 wind turbines, at a total nameplate capacity of 29.2-megawatts. BluEarth submitted that the wind turbines would have a shorter hub height, and the reduction of the number of turbines would correspondingly reduce the size of the Project site, the total length of access roads, and the length of the collector system. The Amended Project's remaining turbines would use sites within 50 metres of the locations approved in the original application. BluEarth also submitted that the Amended Project would no longer require noise reduced operation modes, and other noise mitigation measures, such as noise attenuation barriers.

The AUC held that the following factors would reduce the overall effects of the Project as a result of the application:

(a) Reduction in the project area;

(b) The decrease in size and number of wind turbines;

(c) The increased distance between residences and Amended Project components; and

(d) Resulting reductions in noise levels.

The AUC held that none of the parties who objected to the Amended Project had standing, as the decision on the alteration of the Project would not directly and adversely affect their rights. The AUC also held that the installation of noise barriers and other mitigation measures was no longer necessary as a condition for the Project, due to the reduction in size and scope.

The AUC therefore found that the Amended Project was in the public interest, and conditionally approved the application.

Alberta Electric System Operator Compliance filing pursuant to Decision 2013-135 regarding ISO rules Section 302.1 (Decision 3528-D01-2015)
Compliance Filing – AESO Rule - Real Time Transmission Constraint Management

This decision was a compliance filing made by the Alberta Electric System Operator ("AESO") pursuant to Decision 2013-135, wherein the AUC upheld complaints by ENMAX Energy Corporation ("ENMAX") and ATCO Power Ltd.("ATCO") regarding the ISO rules Section 302.1: Real Time Constraint management (the "TCM Rule"). The AUC, in Decision 2013-135 held that the TCM Rule was technically deficient, did not support the fair, efficient and openly competitive operation of the electricity market in Alberta, and was not in the public interest. The AUC directed the AESO to change the TCM Rule in accordance with five directions. This decision considered the AESO's compliance with directions 1 and 2, which read as follows:

(a) Include the principles of the real-time transmission must-run ("RTMR") proposal outlined in paragraph 191 in the Energy Market Merit Order/pro-rata mechanism ("Direction 1); and

(b) Increase the use of Transmission Must Run ("TMR") in conjunction with Dispatch Down Service ("DDS") in an effort to minimize price distortion in the market, particularly to address foreseen occurrences of congestion ("Direction 2").

The AESO subsequently filed a revised proposed TCM Rule, and indicated that changes to other ISO rules would be required to implement the proposed revisions to the TCM Rule. The AESO requested that the AUC order the TCM Rule to become effective on a future date to be provided for by the AESO, once it can confirm that all necessary information technology changes needed to implement the revised TCM Rule have been completed.

The AESO submitted that it adapted the RTMR to a transmission constraint rebalancing ("TCR") mechanism. The TCR would be the delivery of energy to restore the energy balance on the interconnected electric system downstream of the constraint after a sequence of measures are followed to mitigate the constraint in the proposed TCM Rule.

The AESO submitted that the TCR mechanism would not affect the single clearing price for electric energy, in noting that if a generator in merit is excluded, the higher priced generators dispatched to effect the TCR mechanism would not set the pool price. Under the AESO filing, the generators receiving dispatches for TCR receive a TCR payment in addition to the pool price on an "as-bid" basis for the incremental TCR energy only. The AESO submitted that the costs of generation re-dispatch should not include compensation for lost opportunity costs arising from being constrained down as a result of a constraint ("Constrain Down Payments"). The AESO contemplated that these costs should be recovered through "constraint mitigation charges" in the Demand Transmission Service (or Rate DTS) and Fort Nelson Demand Transmission Service (or Rate FTS) in the AESO tariff. The AESO indicated that should the AUC approve this compliance filing, the AESO intends to introduce the necessary tariff revisions to recover the costs of TCR payments in its next ISO tariff update application.

<u>Direction 1</u>

The AUC held that the AESO's proposed revised TCM Rule sufficiently reflected the principles set out in Direction 1, and found the proposed revised TCM Rule to comply with Direction 1. The AUC held that the introduction of a constrain down payment, as advocated for by ATCO, Capital Power Corporation ("Capital Power"), Milner Power Inc. ("Milner"), and TransCanada Energy Ltd. ("TCE"), was not relevant to determining whether the AESO had complied with Direction 1, and was not necessary to achieve compliance with Direction 1, citing Decision 2009-042 where it held that there was no legislated requirement for the AESO to pay compensation for generators who are constrained down.

Several parties, including ENMAX, Capital Power, TCE, ATCO, and Milner submitted that the AESO's proposed TCM Rule did not comply with the AUC's directions in Decision 2013-135, and proposed a downstream clearing price for TCR payments, whereby generators would be paid a price equal to the offer price in the last downstream offer block dispatched to alleviate the transmission constraint.

The AUC rejected the proposed downstream clearing price, noting that prices are likely to be higher under a downstream clearing price than under a pay-as-bid approach. The AUC therefore found that the pay-as-bid approach was preferable, and better served the public interest.

ATCO, Milner and TCE also took issue with the AESO's plan to file associated changes to ISO Rules as expedited rules under section 20.6 of the *Electric Utilities Act*, and submitted that any such changes should be subject to regulatory oversight, so that parties can test the changes and examine whether the changes are in the public interest.

The AUC held that it had previously expressed its concern to see the changes to the TCM Rule proceed as expeditiously as practical. Accordingly, the AUC held that the AESO's determination to file the consequential amendments as expedited rules was not offensive, nor would it contravene its directions in Decision 2013-135.

Direction 2

With respect to Direction 2 , the AESO stated that it intended to continue to follow the mitigation measures involving TMR under the existing TCM Rule, using contracted TMR where effective, then using non-contracted TMR. The AESO stated that it intends to revise the TCM Rule in order to increase the use of TMR to account for out-flow constraints (whereas the existing TCM Rule only accounts for in-flow constraints.) Capital Power, the Utilities Consumer Advocate, and others supported the AESO's argument that it was compliant with Direction 2.

The AESO submitted that DDS service is intended to offset the potential price distortion caused when TMR is dispatched to help alleviate an in-flow constraint, but would not be needed for an out-flow constraint as the unconstrained energy price would be preserved by curtailing generators upstream of the constraint. (An in-flow constraint is where there is insufficient in-merit generation in an area to reliably serve load. To manage this constraint, generators with TMR contracts are dispatched, or in situations where there are no effective TMR generators, the AESO issues a directive to a generator for non-contracted TMR. An out-flow constraint is where there is insufficient capability on the transmission system to permit all in-merit generators to offer their energy to load on the transmission system. To manage this constraint, generators upstream of the constraint location are constrained down, and the system is rebalanced by dispatching an out-of-merit generator downstream of the constraint location.)

The AUC held that the representations made by the AESO in respect of its efforts to increase the use of TMR in conjunction with DDS were sufficient to achieve compliance with Direction 2. The AUC considered the increased use of TMR/DDS in instances of foreseen constraints as an important tool to protect consumers from needlessly higher prices caused by the existing TCM Rule.

Decision

The AUC therefore held that the AESO complied with Direction 1 and Direction 2 in Decision 2013-135 and thereby approved the revised TCM Rule, effective on a date to be determined by the AESO once all the necessary information technology system changes have been completed in order to implement the revised TCM Rule.

ATCO Electric Ltd. Application for Review of Decision 2014-283 (Decision 3523-D01-2015)
Review and Variance – Purchase Price

ATCO Electric Ltd. ("ATCO") requested a review of AUC Decision 2014-283 (the "Panel Decision"). In the Panel Decision, the AUC was prepared to approve the purchase price for the Kearl 240-kV line (the "Kearl Line") that reflected the construction costs incurred by Imperial Oil Resources Ventures Limited ("IORVL"). However, the AUC found that the inclusion of Allowance for Funds Used During Construction ("AFUDC") costs was not reasonable. ATCO sought approval to include final capital costs of approximately $80.5 million for the acquisition of the Kearl Line, $75.3 million of which was attributed to the purchase cost of the Kearl Line. The remaining $5.2 million was described by ATCO as an account of both AFUDC costs and accumulated depreciation.

ATCO applied for a review of the Panel Decision based on the following two grounds:

(a) That the Panel Decision was based on an unsupported, factually incorrect assumption that the capital project cost for the Kearl Line included interest during construction. ATCO alleged that the AUC made an error of fact, law and/or jurisdiction in making a finding inconsistent with uncontroverted evidence that the AFUDC costs were the only items in the Kearl Line purchase price related to project financing; and

(b) The implementation of the *Transmission Deficiency Regulation*, that came into force on September 22, 2014, which specifically recognizes the Market Participant Choice framework, constitutes new facts or changed circumstances not previously available and could not have been placed before the AUC. ATCO alleged the recognition of the framework created new circumstances that impacted the appropriateness of the AUC's determination not to include legitimate financing costs in the Kearl Line project costs.

In the Panel Decision, the AUC denied the inclusion of AFUDC costs on the basis that IORVL is not a regulated utility. However, ATCO in its review application submitted that the exclusion of financing costs altogether was not reasonable, as the financing costs themselves were clearly not zero cost. ATCO also submitted that a failure on the part of the AUC to recognize and include legitimate construction and financing costs could act as a disincentive to similar transactions, resulting in an inconsistency with the policy objectives of the Transmission Deficiency Regulation.

The AUC rejected the first ground advanced by ATCO, holding that the wording of the Panel Decision did not specifically address interest costs incurred by IORVL. Rather, the Panel Decision disallowed the recovery of amounts described as AFUDC costs. As IORVL was not a regulated entity, it had no entitlement to, and no reasonable expectation of, recovering amounts described as AFUDC costs. The AUC also pointed to the determination in the Panel Decision whereby the AUC found that ATCO did not incur interest costs or forego earnings during construction of the Kearl Line. Therefore, the AUC determined that:

(a) ATCO opted to pay IORVL an AFUDC cost amount equivalent to what IORVL would have received had it been a regulated entity; and

(b) The record of the Panel Decision did not support the first ground of review asserted by ATCO.

The AUC also rejected the second ground of review advanced by ATCO as without merit. The AUC noted that the Market Participant Choice framework was implemented on March 1, 2014, while the Panel Decision was rendered on October 2, 2014. The AUC also noted that the Kearl Line began construction in 2009, was energized in 2010, and the transfer to ATCO was completed by July 31, 2012, all of which predated the inception of the Market Participant Choice framework, and the *Transmission Deficiency Regulation*. The AUC ruled that the disallowance of costs prior to the inception of new legislation does not act in any way as a disincentive to use the framework. The AUC further noted that this was particularly so, as the Panel Decision did not make a general finding concerning the regulatory treatment of interest during construction within the Market Participant Choice Framework.

The AUC therefore dismissed ATCO's application for review and variance of the Panel Decision.

NATIONAL ENERGY BOARD

Ruger Energy Inc. Application pursuant to paragraph 74(1)(d) of the National Energy Board Act for leave to abandon the Alsask Pipeline (Decision MHW-001-2014)
Leave to Abandon

Ruger Energy Inc. ("Ruger") applied to the NEB pursuant to paragraph 74(1)(d) of the *National Energy Board Act*, and section 50 of the *National Energy Board Onshore Pipeline Regulations* to abandon in-place the Alsask pipeline and to excavate and remove a riser, at a total estimated cost of $2,000. The Alsask pipeline - which is approximately 580 metres in length, and spans the Alberta-Saskatchewan border – was deactivated in 2012 pursuant to Order MO-031-2012.

Ruger committed to abandon the pipeline in accordance with Canadian Standards Association Z662-11, Oil and Gas Pipeline Systems. The NEB directed that Ruger's abandonment activities be carried out in accordance with Z662-11, and found that given the small diameter of the pipe, that abandonment in-place was acceptable under the circumstances.

With respect to costs of abandonment, the NEB held that it was satisfied that Ruger had sufficient funds to conduct the abandonment. However, in citing Reasons for Decision RH-2-2008, the NEB imposed Condition 9 as part of its order to Ruger, requiring Ruger to file a letter acknowledging that it has ongoing financial responsibility for as long as it owns the Alsask Pipeline.

On environmental matters, the NEB held that abandonment in-place was acceptable, as the native prairie environment over which the Alsask pipeline passes is sensitive to disturbance. The NEB reasoned that there was a low risk for subsidence given the small size of the pipeline, and that the risk of the pipe becoming a conduit for water was also low, given the flat terrain and relatively short distance of the Alsask pipeline.

The NEB also required Ruger to provide assurance that any contamination from the Alsask pipeline would be identified prior to the commencement of abandonment activities. Therefore, the NEB imposed:

(a) Condition 4 on Ruger, requiring it to file a Phase I Environmental Site Assessment to evaluate potential for contamination; and

(b) Condition 6, requiring Ruger to develop an Environmental Protection Plan to prevent and respond to spills that may occur during abandonment activities.

Accordingly, the NEB granted Ruger leave to abandon the Alsask pipeline, subject to the conditions in Order ZO-R738-001-2015.

NOVA Gas Transmission Ltd. Application dated 8 November 2013 for the North Montney Mainline Project (Report GH-001-2014)
Facility Application - CPCN - Tolling Methodology

NOVA Gas Transmission Ltd. ("NGTL") filed an application with the NEB on November 8, 2013 seeking approval to construct and operate the North Montney Mainline ("NMML"), designed to transport natural gas from the North Montney area in British Columbia to the NGTL system. NGTL also proposed to connect the NMML to the proposed Prince Rupert Gas Transmission ("PRGT") pipeline, and on to gas markets as liquefied natural gas ("LNG") at the Pacific Northwest LNG facility, located near Prince Rupert.

The NMML consists of two pipeline sections and related pipeline facilities, composed of:

(a) 182 km pipeline from an interconnection with the existing Saturn section of the Groundbirch Mainline, to a point located in Unit 44, Block L, Group 94-1-13 ("Aitken Creek Section");

(b) 119 km pipeline from the Aitken Creek Section to a point located in Unit 30, Block K, Group 94-G-7 ("Kahta Section");

(c) Three compressor stations capable of bi-directional capability, two on the Aitken Creek Section, and one on the existing Groundbirch Mainline;

(d) 16 meter stations, with 6 on the Aitken Creek Section and 10 on the Kahta Section. One of the meter stations would accommodate delivery of gas flows into the proposed PRGT pipeline ("Mackie Creek Interconnection"); and

(e) Other temporary infrastructure,

(collectively, the "Project").

NGTL requested the following relief from the NEB in order to construct and operate the NMML:

(a) A Certificate pursuant to section 52 of the *National Energy Board Act* ("*NEB Act*") authorizing the construction and operation of the Project;

(b) An Order pursuant to section 58 of the *NEB Act*, exempting NGTL from the requirements of subsections 31(c), 31(d) and 33 of the *NEB Act* in relation to temporary infrastructure required in advance of and during construction;

(c) An Order pursuant to Part IV of the *NEB Act* affirming that:

   (i) Prudently incurred costs required to provide service on the applied-for facilities will be included in the determination of the NGTL system revenue requirement; and

   (ii) The tolls for services on the applied-for facilities would be calculated using the same methodology used to calculate tolls for services on all other facilities on the NGTL system, as determined through Board order from time to time.

The NEB held an oral hearing on the NMML application during October 2014 and November 2014.

Tolling Methodology

Many interveners took issue with the impact that "rolled-in" tolling of the Project would have on existing shippers on the NGTL system, as the NMML would introduce a new FT-D1 delivery point, as well as several new receipt points.

The NEB held that in determining the appropriate tolling methodology, it has a wide discretion in choosing the method to be used, and the factors to be considered in assessing the justness and reasonableness of tolls. Accordingly, the NEB considered:

(a) The degree to which the proposed facilities would be integrated with the rest of the pipeline system; and

(b) The nature of the service to be provided by the proposed facilities in relation to the service provided by the rest of the pipeline system.

The Board found that gas flow patterns for the NMML are expected to change significantly when North Montney gas production is first delivered at the Mackie Creek Interconnection for transportation on the PRGT pipeline in 2019. Therefore, the NEB examined the NMML for two distinct periods:

(a) The "Transition Period", which starts when gas begins to flow on the NMML and expires when North Montney gas production is first delivered at the Mackie Creek Interconnection; and

(b) The "Long-Term Phase", which starts at the end of the Transition Period.

The NEB held that, for the Long-Term Phase, the Project would not be meaningfully integrated with the existing NGTL system, while there would be physical and operational integration during the Transition Period. The NEB held that while the Project would be physically connected to the NGTL system, it was connected at an extremity of the NGTL system, and was geographically separated from the remainder of the NGTL system. This in effect, precluded the Project from affecting the capacity of the existing NGTL system.

After the Transition Period, the NEB found that the Project would be used separately and largely independently of the NGTL system, noting that the gas flows between the Project and the NGTL system would be minimal and intermittent, with the Mackie Creek to Saturn portion being used well below capacity. While the NEB noted that it recognized the benefit of the access to the NOVA Inventory Transfer ("NIT") market, it held that such access was not a determining factor, and that "evidence that it is convenient or preferable for a shipper to access the NIT market without paying stacked tolls is not a persuasive factor in determining integration."

The NEB held that the service held by Progress Energy Canada Ltd. ("Progress") on the Project was primarily a point-to-point service in the long term, rather than as a receipt-point to market hub service. The NEB also found that the NGTL tolling methodology, if applied to the Project, would unnecessarily constrain Project revenues during the Transition Period prior to 2019. The NEB determined that the revenue constraints would therefore be borne by existing NGTL shippers, resulting in an inappropriate level of cross-subsidization. Accordingly, the NEB found no direct link between the cost of the proposed facilities and NGTL's rolled-in tolling methodology.

The NEB also found that the tolling methodology would be unjustly discriminatory, as the NEB determined that Project shippers would be accessing the NGTL system at a toll less than the applicable tolls downstream of Project shippers. While the NEB noted that the volume weighted aspects of the methodology may account for some of this discrepancy, it also found that the tolling methodology created irregular tolling patterns, even in the long term.

The NEB therefore denied NGTL's requests to include the costs of the Project on a rolled-in basis, citing its determinations on the evidence presented that the proposed tolling would not sufficiently satisfy cost causation principles or the goal of economic efficiency. Therefore the tolls derived from NGTL's proposal would not be just and reasonable. The NEB did however provide NGTL with directions regarding tolling that would result in just and reasonable tolls. The NEB's specific directions can be found in Order TG-002-2015.

The NEB required NGTL to establish a separate cost pool for the Project including all expenditures and revenue related to the Project, and to maintain it for the life of the Project, or until directed otherwise. In the Transition Period the NEB held that it would allow NGTL to charge Project shippers tolls derived by combining the incremental revenue requirement of the Project with that of the existing NGTL system, and applying its current tolling methodology. In addition, the NEB determined that NGTL must accumulate in a deferral account, the portion of the Project's cost of service that is not recovered by incremental revenue from Project-related transportation contracts for disposition in a future application.

The NEB found that after the Transition Period, in the Long-Term Phase, NGTL will have the option of:

(a) Implementing stand-alone tolling; or

(b) Applying to the Board for a revised tolling methodology.

Economic Feasibility and Need

The NEB held that there was adequate supply of natural gas to support the Project.

The Board found that the supply expected to flow on the Project can access global LNG markets via the proposed PRGT pipeline and the Pacific North West LNG Facility, which will be able to absorb Project volumes. However, prior to the start-up of the LNG facilities, the incremental volumes will access the North American market. In the absence of the planned LNG facilities, the NEB held that there would be insufficient evidence to assess the outlook for gas demand in relevant markets, as the volumes would need to flow onto the existing NGTL system. NGTL also acknowledged that a lack of deliveries to LNG export terminals would require a significant reconfiguration of the Project. On this basis, the NEB imposed "Condition 4", requiring NGTL to file, prior to commencing construction, confirmation that:

(a) Progress has made a positive final investment decision on the proposed LNG facilities;

(b) TransCanada PipeLines Ltd. is proceeding with the construction of the PRGT pipeline; and

(c) The delivery contracts between NGTL and Progress continue to be in effect for the same quantity of gas reaching 2,340 TJ/d by 2019.

The NEB held that Condition 4 would establish sufficient contracts to support the design capacity of the Project, and that the facilities would have sufficient commercial support to proceed.

With respect to the physical sizing of the Project, the NEB found that the expected flows on the Mackie Creek to Saturn portion of the Project were not sufficient to support a finding that the design capacity was appropriate. However, the NEB was satisfied that some capacity was required to satisfy the requests of customers prior to 2019. Nevertheless, the NEB held that its finding with respect to tolling directions would leave the potential risks of mis-sizing or overbuilding the facilities with NGTL and the project shippers, and not on the existing NGTL shippers.

Facilities and Emergency Response

The Salteau First Nations ("SFN") argued that the NEB had to first determine whether the project was within federal jurisdiction, before it could turn to questions on the appropriateness of the facilities applied for. SFN noted that the Project would be located entirely within British Columbia, and lacked a high degree of physical interconnection with the NGTL system.

The NEB dismissed the issue from SFN, citing that jurisdiction of the NEB was not raised as an issue, no evidence was adduced on the matter, and no notice of constitutional question was served on the Attorney General of Canada.

With respect to many aspects of facilities and emergency response plans, interveners raised no concerns with the NEB.

With respect to watercourse crossings, NGTL submitted that it planned a total of 87 water crossings, using open cut, isolation cut, and horizontal direction drilling ("HDD") techniques. NGTL planned on using HDD where feasible as the primary crossing technique to reduce disturbances on waterways. The NEB was satisfied with the HDD approach adopted by NGTL, but directed NGTL to file its HDD execution program prior to construction.

Public Consultation

NGTL submitted that its Stakeholder Engagement Program would ensure that all stakeholders were aware of the Project plans, and would have an opportunity to provide input. NGTL submitted that it consulted with all those likely to be directly or indirectly affected by the project or that may have a potential interest in the Project.

One landowner expressed concerns with NGTL's engagement with respect to selecting a location for the Groundbirch compressor site. NGTL replied, noting that it continues to work towards resolving the landowner's concerns by shifting the location of the compressor station to reduce visual and noise impacts on the property.

The NEB held that the consultation and stakeholder engagement proposed by NGTL was appropriate for the size and scope of the Project. With respect to the location of the compressor station, the NEB encouraged both parties to continue discussions, and ordered NGTL to file a plan to mitigate, avoid or minimize potential impacts on their property including future development plans.

Aboriginal Matters

NGTL submitted that it consulted with 25 different Aboriginal groups located near or within the Project area, and facilitated 14 different traditional land use studies and traditional ecological knowledge studies.

The Blueberry River First Nations ("BRFN") raised concerns that the BRFN Treaty rights were not accommodated, nor was the BRFN meaningfully consulted by NGTL with respect to routing options for the Kahta section of the Project.

Fort Nelson First Nation raised concerns with the Project, notably that the cumulative effects of the Project will cause adverse effects on lands, wildlife and other resources.

The Prophet River First Nation ("PRFN") stated that NGTL mischaracterized its interactions with PRFN, resulting in delays in reaching an agreement on capacity funding, which in turn resulted in PRFN being unable to gather necessary cultural evidence by the NEB's deadline to file intervener evidence. PRFN did however raise concerns that three culture camps used for the South-Sikanni Culture Camp could be potentially affected by the Kahta section of the Project.

Similarly, SFN submitted that the timelines and hearing process for the Project were insufficient to allow any meaningful consultation.

The West Moberly First Nations ("WMFN") submitted that a number of traditional land use resources and activities would likely by impacted by the Project, noting that increased industrialization has gradually encroached on WMFN's territory, limiting its abilities to engage in traditional practices due to fragmentation.

NGTL replied, stating that its consultation was extensive, and provided each group with information about the Project, and provided opportunities to meet and discuss each group's concerns with the Project. NGTL also submitted that the three camps identified by PRFN would not intersect with the proposed route for the Project, and therefore NGTL did not anticipate any Project related effects. NGTL stated that it would continue to engage with potentially affected Aboriginal communities throughout the lifecycle of the Project.

The NEB determined that NGTL's implementation of its consultation program was adequate, and noted NGTL's commitment to continue to engage with potentially affected Aboriginal Communities.

Pipeline Routing

NGTL proposed six major alternative corridors for the Aitken Creek section. The WMFN and SFN did not support the applied for route which would traverse the Peace Moberly Tract.

The NEB determined that NGTL's approach for the assessment of the Project's potential effect on traditional land use and resource use was generally acceptable, with the exception of the Peace Moberly Tract. The NEB was not in full agreement (one panel member presented dissenting reasons) on the routing of the Project and its impacts on Aboriginal traditional uses within the Peace Moberly Tract.

The majority of the NEB recommended approval of NGTL's applied for route through the Peace Moberly Tract, but imposed additional measures on NGTL it deemed necessary for the route to be in the public interest. The majority noted that NGTL pursued its preferred route through the Peace Moberly Tract over the significant concerns raised early on by SFN and WMFN. The majority noted that despite its knowledge of these concerns, NGTL did not substantively revise its design, nor propose additional measures that would eliminate the Project's potential effects on the use of the lands and resources in the Peace Moberly Tract by the SFN and WMFN. The majority also noted that NGTL did not adjust its preferred route within the Peace Moberly Tract.

The majority of the NEB held that NGTL did not sufficiently justify its preferred route commensurate with the demonstration of concern and the evidence provided by Aboriginal groups in respect of its potential impacts, and therefore found NGTL's approach unsatisfactory. The majority noted that it expects applicants to clearly demonstrate:

(a) How the proposed project is the most appropriate option for the needs that the project would satisfy while serving the public interest; and

(b) How the input and concerns the proponent received from potentially impacted parties have influenced the design, construction or operation of the proposed project.

In finding that the concerns of SFN and WMFN were significant and had merit, the majority held that it expected NGTL to demonstrate justification for its preferred route commensurate with the degree of concerns raised, or demonstrate how it revised the Project to address those concerns.

Therefore, in order to accommodate the concerns of the SFN and WMFN, the majority imposed conditions 11, 12 and 35 to its decision, which require NGTL to:

(a) Submit to the NEB for approval a protection plan specific to the Peace Moberly Tract that outlines additional measures to eliminate or minimize impacts within the Peace Moberly Tract, including impacts on traditional land use by Aboriginal communities;

(b) Submit to the NEB for approval a plan for consulting with SFN and WMFN on the development of its planned mitigation measures to protect the Peace Moberly Tract; and

(c) To report to the NEB on its consultation efforts and the effectiveness of the measures implemented through monitoring reports during the operation phase of the Project.

The majority noted that it attached significant weight to the importance of these conditions on its decision, and expressed its expectations for the fulfillment of these conditions to be correspondingly significant by NGTL.

The dissenting member of the NEB shared the majority's finding that NGTL did not provide persuasive evidence that it thoroughly investigated alternatives that would avoid the Peace Moberly Tract. The conditions provided for by the majority were noted as helpful in mitigating impacts, but the dissenting member found that they would not avoid fragmentation of the Peace Moberly Tract.

The dissenting member found that the Peace Moberly Tract is "one of the last remaining undisturbed and high value traditional use areas in close proximity to these First Nations." Accordingly, the dissenting member determined that an approval of projects that break up such contiguous lands must be strongly and demonstrably justified by the project proponent.

The dissenting member also accepted the evidence of the SFN and WMFN respecting the serious implications of encroachment on the Peace Moberly Tract, as the proposed Project route would have the potential to significantly impact SFN and WMFN's ability to undertake their traditional practices in a meaningful way. The dissenting member also accepted evidence that such encroachment would undermine ongoing negotiations between First Nations and the Province of British Columbia.

The dissenting member therefore recommended that the Governor in Council approve the Kahta section of the Project, but deny the portion of the Project from Mackie Creek to Saturn for the above reasons.

Environmental Impacts and Mitigation

NGTL proposed several mitigation strategies to avoid or minimize effects on the Project. NGTL relied primarily on paralleling existing linear disturbances, reducing the number of watercourse crossings, and routing to avoid sensitive environmental areas. NGTL also proposed to salvage top soil from construction in order to mitigate impacts to soil and soil quality, as well as controlling topsoil loss from erosion.

The NEB was satisfied with the site-specific mitigation measures proposed, and implemented the following conditions on NGTL:

(a) Requiring NGTL to file a Project-specific environmental protection plan 60 days prior to commencement of construction of the Project, and 45 days prior to construction of temporary infrastructure, providing clear and unambiguous language setting out the goal, mitigation options and decision making criteria for selecting mitigation options;

(b) Requiring NGTL to file monthly construction reports, including any environmental, socio-economic, safety, security, and compliance issues encountered during construction; and

(c) Requiring NGTL to file post-construction and environmental monitoring reports.

Cumulative Effects Assessment

NGTL identified past development activities that may contribute to cumulative effects in the region, including forestry, oil and gas, utilities, residential development, and future developments adjacent to the Project. NGTL identified adverse residual effect from the Project for the following valued environmental and socio-economic components: vegetation and wetlands, wildlife and wildlife habitat, water quality, fish and fish habitat, human occupancy and resource use, traditional land and resource use.

NGTL applied a three step screening process to identify the impact of the Project for cumulative effects:

(a) Is there a residual effect as a result of the Project?

(b) Does the residual effect overlap spatially and temporally with those of other past, present or reasonably foreseeable future projects?

(c) Is there a reasonable expectation that the contribution (i.e. addition) of the Project's residual effects would cause a change in cumulative environmental effects that could affect the quality or sustainability of the valued environmental and socio-economic components, and therefore require further assessment?

The NEB expressed reservations about the third part of the screening process, noting that it is not an accepted method, and was not supported by any independent or peer reviewed literature. The NEB expressed a concern that this screening measure presupposes the intended outcome on cumulative effects assessment. Notably, the NEB also found that NGTL's assumptions for cumulative effects were inconsistent with its filings, and did not identify associated or related wells for cumulative effects, but relied on them for the economic assumptions for the Project. The NEB held that a proponent cannot suggest supply exists to justify the need for its proposed pipeline for the economic feasibility analysis, and then suggest that development of the supply is a hypothetical in examining environmental impacts. However, after review of additional information provided by NGTL in the course of the proceeding, the NEB held that the modelling reflected a reasonable model of potential trends.

The NEB held that most of the cumulative effects would be limited to the duration of construction, would be minor in nature and would be localized. The NEB was satisfied with NGTL's proposed mitigation measures for the impacts identified, and that in conjunction with the NEB's imposed conditions and the implementation of NGTL's mitigation measures, that the Project would not likely cause significant adverse environmental effects.

Decision

In the result:

(a) The majority of the Board recommended that a CPCN be issued under section 52 of the *NEB Act*, for the construction and operation of the NMML. The NEB set out terms and conditions to which the CPCN would be subject if the Governor in Council were to direct the NEB to issue the CPCN;

(b) The majority of the Board decided that the construction and operation of temporary infrastructure for the NMML (the "Section 58 Facilities") were in the public interest. The NEB issued Order XG-N081-010-2015 approving the Section 58 Facilities and exempting NGTL from subsections 31(c) and 31(d), and section 33 of the *NEB Act*, subject to conditions; and

(c) The NEB denied NGTL's requests for the Part IV Questions. However, the NEB provided NGTL with directions regarding tolling in Order TG-002-2015.