ISSUE:
MAY 2016
DECISIONS

REGULATORY
LAW CHAMBERS

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.

<u>IN THIS ISSUE:</u>

ALBERTA COURT OF APPEAL

Direct Energy Regulated Services v Alberta Utilities Commission, 2016 ABCA 156
Regulated Rate Option – Leave to Appeal

Direct Energy Regulated Services ("DERS") applied for leave to appeal Decision 2941-D01-2015 of the AUC pursuant to section 29(1) of the *Alberta Utilities Commission Act*.

The Alberta Court of Appeal ("ABCA") described DERS' risk margin applied for in Decision 2941-D01-2015 as based on a methodology that utilized rolling weighted average historical systematic gains and losses over a 12-month period, plus forward-looking compensation by adding one standard deviation for volatility to the rolling weighted average.

The Utilities Consumer Advocate ("UCA") proposed an alternate methodology to calculate the risk margin to the AUC, using:

- a variable adaptive component (using a 12-month rolling average of commodity gains and losses without commodity risk compensation, divided by the commodity revenues without commodity risk compensation over the same period); and
- a risk cycle component (a fixed $/megawatt-hour value calculated using historical data at the beginning of the energy price setting plan ("EPSP") and updated annually).

The AUC issued Decision 2941-D01-2015 where it rejected DERS' proposed risk margin and accepted the UCA's methodology as providing a reasonable method for regulated rate option ("RRO") providers to forecast expected net systematic gains and losses over a 12 month period using historical data. The AUC noted in providing its finding that a hypothetical application of DERS' methodology would have provided DERS with an additional gain of $16.5 million over its previously EPSP.

DERS applied for a review of Decision 2941-D01-2015, which was denied by the AUC.

DERS submitted that the AUC erred in jurisdiction or law by:

- Holding that DERS' risk margin in its EPSP was restricted to allowing DERS to recover only risk-related costs and expenses, instead of just and reasonable compensation for bearing financial risk, in addition to its prudent costs and expenses, contrary to sections 5 and 6 of the *Regulated Rate Option Regulation*; and
- Imposing a method of calculating the risk margin which requires backward looking adjustments to set the level of compensation to cover the actual losses incurred, contrary to section 3(2) and 6(2) of the *Regulated Rate Option Regulation* which prohibits the use of deferral accounts, true-ups, rate riders or other similar accounts.

In 2014, DERS, along with ENMAX Energy Corporation, and EPCOR Energy Alberta GP Inc., as RRO providers, filed their respective 2014-2018 EPSP. DERS has applied for a regulated rate tariff ("RRT") that provided for a specific risk margin pursuant to section 1(1) of the *Regulated Rate Option Regulation*, which defines a risk margin as:

> The just and reasonable financial compensation that an owner's regulatory authority approves for the owner based on the financial risks
>
> (i) that remain with the owner, and
>
> (ii) that are associated with the supply of electricity services to regulated rate customers.

DERS submitted that the methodology approved by the AUC in Decision 2941-D01-2015 would impede the development of a fair, efficient and openly competitive electricity market, and would create an unfair and artificially low RRO price, stunting the development of fair and open competition. DERS further submitted that the issue was significant, since RRO providers are obligated to provide electricity services, and that Decision 2941-D01-2015 would set a dangerous precedent.

The UCA submitted that DERS incorrectly interpreted section 6(1) of the *Regulated Rate Option Regulation* as requiring subsection (a) and (c) to be read as mutually exclusive requirements. Instead the UCA submitted that the risk margin should provide a reasonable opportunity for DERS to recover its prudent costs and expenses associated with its risk as well as additional financial compensation for the financial risks assumed. The UCA submitted that the AUC appropriately applied the *Regulated Rate Option Regulation*, and specifically distinguished the UCA methodology from a deferral account or true-up, since it did not actually provide a settlement mechanism for the exact amount of losses incurred by an RRO provider.

The ABCA determined that the questions raised by DERS involve the AUC's ratemaking authority, which is at the core of its mandate and expertise. Accordingly, the ABCA afforded the AUC's reasons a high degree of deference.

The ABCA held that the AUC expressly considered section 6 of the *Regulated Rate Option Regulation* in setting the risk margin, and that there was no indication from the AUC's reasons that the AUC considered the prudent costs of the owner separately from the just and reasonable financial compensation for the risks in opting for the UCA's methodology.

The ABCA held that the AUC did not err in law or jurisdiction in selecting the UCA methodology, pointing to the AUC's finding that there should not be risk compensation in excess of the full recovery of costs related to risk.

The ABCA also rejected the submission that the UCA methodology consisted of a deferral account, pointing to testimony noted by the AUC in providing its findings that the UCA methodology was prospective, and left a risk of gain or loss over the EPSP.

The ABCA, in rejecting the submission that the UCA methodology consisted of a deferral account, also determined that the issue was a question of mixed fact and law, and therefore expressly excluded from appellate review.

The ABCA held that DERS had failed to demonstrate a meritorious argument on the questions of law. Accordingly, the ABCA held that Decision 2941-D01-2015 fell within a range of possible acceptable outcomes that are defensible in respect of the facts and the law, and therefore dismissed the application.

ALBERTA ENERGY REGULATOR

Bulletin 2016-12: Fort McMurray Wildfire – Emergency Protocol for Oil Sands Operators
Emergency Protocol – Bulletin

The AER requested that operators contact the AER if they require information from the provincial operations centre ("POC") regarding wildfires near Fort McMurray.

The AER noted that operators with infrastructure in the fire path have AER approval to build walls and berms to protect their facilities, on the condition that they not create adverse public or environmental impacts. The AER noted that it will conduct site inspections once the emergency response to the wildfires has ended.

The AER further noted that the AER's Fort McMurray Regional Office has been evacuated until further notice, and all calls and e-mails to that office are being routed to the Bonnyville Field Centre.

For emergencies, the AER has asked operators to contact the AER's 24-hour Energy and Environmental Emergency Line at 1-800-222-6514, or at BCMTeam@aer.ca.

For non-emergencies, the AER requested that operators contact the AER at 1-855-297-8311, or inquiries@aer.ca.

Bulletin 2016-13: Fort McMurray Wildfires – Resuming Operations
Emergency Protocol – Bulletin

The AER announced that it was advising operators planning to resume operations in the Regional Municipality of Wood Buffalo after unplanned shutdowns, that all notification requirements for unplanned shutdowns remain in place. This includes maintaining all documentation during start-up operations, which the AER noted that it will require at a later date.

Bulletin 2016-14: Release of New Subsoil Salinity Tool Assessment Checklist
Subsoil Salinity Tool – Bulletin

The AER announced that it had implemented a new process for accepting Subsoil Salinity Tool ("SST") assessments for review, including the development of a new SST Assessment Checklist.

The AER noted that effective immediately, companies must provide the SST Assessment Checklist with their SST assessment submissions to the AER.

The AER noted that the SST Assessment Checklist covers the minimum information that must be included in an SST assessment.

The AER noted that SST assessments submitted prior to May 13, 2016 will be reviewed, but that if the SST assessment is rejected, that the company withdraw the assessment and resubmit using the SST Assessment Checklist.

A copy of the SST Assessment Checklist can be found here.

Bulletin 2016-15: 2016 AER Administration Fees (Industry Levy)
Levy – Industry Fees – Bulletin

The AER announced its industry levy in the amount of $238,403,000 for 2016-2017. The industry levy represents the revenue required to support AER operations, as approved by the Government of Alberta, and set out in the AER Administration Fees Rules ("AFR") as follows:

Sector	2016 Allocation ($000)	2015
Oil and gas	173,081	174,308
Oil sands	61,746	62,184
Coal	3,576	3,601
Total	238,403	240,093

Invoices for administration fees under the industry levy will be mailed out on May 18, 2015, and are sent to and payable by the party that was the operator as of December 31, 2015. The AER provided a breakdown of the fees payable for oil and gas operators, sorted by total production amounts as follows:

Class (Oil and Gas Operator)	Production (m^3/yr)	Base Fee
1	Service wells	$100.00
2	<300	$100.00

3	300.1-600	$125.00
4	600.1-1200	$312.00
5	1200.1-2000	$750.00
6	2000.1-4000	$1250.00
7	4000.1-6000	$1,625.00
8	>6000.1	$1,875.00

For oil sands production, the AER set the allocation based on the following categories:

Category	**Allocation ($000)**	**Adjustment Factor**
Primary ongoing	7,322	3.592942
Thermal ongoing	23,917	4.736563
Thermal growth	14,643	4.058984
Mining ongoing	9,031	1.799801
Mining growth	6,833	17.031687
Total	**61,746**	

With respect to coal production, the AER set the administration fee based on each mine's share of total production volumes, and set the industry levy as $0.130190 per tonne of coal.

The AER also included in the industry levy, the collection of $3,115,105 to fund the Alberta Upstream Petroleum Research Fund in 2016. The AER advised that payment of all invoices is required by June, 2015, regardless of whether an appeal has been filed or not.

ALBERTA UTILITIES COMMISSION

Notice: Hearing Cancellation and Suspension of Process for the Proposed Fort McMurray West 500-kilovolt Transmission Project
Notice – Cancellation - Suspension

The AUC announced that, due to the catastrophic wildfires in Fort McMurray, the hearing for Proceeding 21030 for the Fort McMurray West 500-kilovolt transmission project was cancelled. The AUC noted that it would be unfair to expect local interveners in the Fort McMurray area to participate in the proceeding during such distressing times.

The AUC therefore announced that it had suspended Proceeding 21030, and would notify the parties of a resumption of the process and a new hearing date in due course.

AltaLink Management Ltd. 2015-2016 General Tariff Application (Decision 3524-D01-2016)
Tariff – Rates

AltaLink Management Ltd. ("AltaLink") applied for approval of its 2015-2016 General Tariff Application ("GTA"), including the following:

- Revenue requirements for the years 2015 and 2016 in the amounts of $810.5 million and $1,001.6 million;
- AltaLink's Tariff, including its terms and conditions of service; and
- Deferral and reserve accounts.

Alberta Direct Connect, the Consumers' Coalition of Alberta ("CCA"), and the Industrial Power Consumers Association of Alberta (collectively, the "RPG"), as well as the Utilities Consumer Advocate ("UCA") intervened in the application.

Expert Evidence

AltaLink took issue with the qualifications and credibility of two witnesses put forth by the RPG. AltaLink argued that the two witnesses put forth by RPG should be rejected.

AltaLink submitted that one witness from the RPG held only a bachelor's degree, had no relevant experience after graduation in 2014, and was not advanced as an expert by the RPG.

AltaLink submitted that another witness from the RPG was not an engineer, was not an economist, and held no degree in economics, math, or statistics, and had no relevant experience in forecasting labour market conditions. AltaLink also submitted that this witness improperly attempted to give opinion evidence on the general intention of AltaLink's contractual relations with its engineering, procurement, and construction management ("EPCm") contractor.

The RPG replied, noting that AltaLink did not challenge the expertise of the witnesses in evidence, and waited only until final argument to raise the issue. The RPG submitted that the evidence provided by its witnesses was properly tendered.

The AUC held that it would not disregard the evidence of the RPG's two witnesses. Rather, the AUC held that it would assess the weight to be given to such evidence.

Forecast Methodology and Assumptions

AltaLink noted that for its forecast of the test period, it had implemented a zero-based budgeting system, assessed all activities required to be performed to meet all of its statutory duties and objectives, as well as re-assess full-time equivalents ("FTE") and contractor levels required to carry out workloads and operating expenses.

AltaLink applied the following forecast parameters to its 2015 and 2016 test period:

(% increase)	**2015**	**2016**
Labour Escalation	--	--
Salary and wages	4.90	2.00
Union	5.00	2.10
Non-union	5.00	2.00
Executive	1.50	0.00
Contractor	4.90	2.00
General Inflation	2.50	2.00
Capital Escalation	5.40	6.50

AltaLink stated that its escalation factors were applied to its expenses using 2014 dollars.

The RPG opposed the escalation rates proposed by AltaLink, noting that it should seek lower contractor rates as a result of the recent economic downturn. Consequently, the RPG recommended reduced contractor escalation rates of 0.7 percent in 2015 and 2.2 percent in 2016, based on the Conference Board of Canada's forecast Alberta Wage and Salary escalation estimates for summer 2015.

The AUC held that it continued to have the same concerns from AltaLink's prior GTA, where it found AltaLink's proposed escalators for contracted manpower to be excessive. The AUC also found that AltaLink did not provide a breakdown of how it established contractor escalation rates. As a result, the AUC found that removing 3.0 percent from AltaLink's forecast escalation for 2015 was reasonable. The AUC also determined that a forecast escalation for contractor costs in 2016 of 1.27 percent was reasonable, being similar to the Conference Board of Canada's forecast Alberta Wage and Salary escalation for summer 2015.

With respect to capital escalation rates, AltaLink submitted it completed an update of escalation rates for direct assign projects, and the three-year compound annual growth rate was 3.4 percent, while the five-year compound annual growth rate was 3.9 percent. AltaLink noted that the growth rates were calculated using 60 percent direct labour costs, 30 percent demand market premium costs, and 10 percent equipment costs.

The RPG stated that due to current labor market conditions, it recommended that labour escalation rate components included in the capital escalation rate should be no greater than the forecast wage inflation in Alberta. Accordingly, the RPG recommended that escalation rates be reduced to 0.66 percent for 2015 and 1.86 percent for 2016.

AltaLink replied that its escalation rates were based on the consumer price index and other publically available indices. AltaLink submitted that the RPG was confusing general inflation with the specific cost escalations for construction of transmission capital projects.

The AUC held that it was not necessary to determine a forecast capital escalation for 2015, as it directed AltaLink to file actual amounts for capital in 2015 elsewhere in the decision. With respect to 2016 values, the AUC determined that the only application of the capital escalator in 2016 was for adjusting expenditures delayed from 2015 to 2016. As a result the AUC determined that the total amounts related to the capital escalator was less than 0.2 percent of capital expenditures. However, due to future impacts due to the calculation of escalations for 2016 being in 2016 dollars, the AUC directed AltaLink to explicitly state the value of the capital escalator being used to generate its unadjusted capital expenditures for each year as well as the capital escalator values used in adjusting any delayed expenditures in AltaLink's next GTA.

The AUC held that AltaLink's consultant that it engaged to develop the capital escalation values did not provide clear details on how the capital escalator was determined for any historical or forecast year. While the AUC noted that a lack of methodological is common for forecasting organizations such as the Conference Board of Canada, provincial and federal governments, as well as financial institutions, when forecasts are used for specific singular purposes, the need for methodological detail is amplified. The AUC therefore directed AltaLink to provide an enhanced level of detail for its escalator factor forecasts.

In view of the limited detail provided in the AltaLink capital escalation forecast, the AUC recalculated AltaLink's capital escalator using a rate of 2.2 percent for labour and 1.8 percent for the remainder of capital expenditures, for a weighted capital escalation factor of 1.95 percent.

For general inflation escalation rates, AltaLink proposed to use 2.1 percent and 2.0 percent for 2015 and 2016 respectively, based upon forecasts from Alberta Treasury Board and the Alberta government's budget forecasts.

The RPG recommended that such interest rates be reduced to 0.9 percent in 2015 and 1.7 percent in 2016 based on the recent economic downturn in Alberta. The UCA recommended that inflation rates be reduced to 0.9 percent and 1.8 percent based on the 2015-2016 First Quarter Update and Economic Statement from Alberta Finance.

The AUC held that the values presented by the UCA were reasonable, as they were the latest and best values available regarding general inflation values. Accordingly, the AUC directed AltaLink to apply general inflation escalators of 0.9 percent for 2015 and 1.8 percent for 2016 in its compliance filing.

Union and Non-Union Escalation

The AUC accepted AltaLink's forecasted union compensation escalation factors as filed, noting that although the 2015 increase is considered high, economic conditions were likely different at the time the contract was signed.

For non-union costs, AltaLink submitted that it forecasted its non-union compensation around three targets:

- To achieve at least market median compensation;
- To achieve at least market median total direct compensation; and
- To achieve market median target total direct compensation by the end of the test period.

Using the above criteria, AltaLink originally forecasted escalators of 6.0 percent for each of 2015 and 2016. These figures were later revised to match AltaLink's proposed union escalators for both 2015 and 2016.

RPG raised several concerns related to AltaLink's non-union labour escalators. Primarily, RPG was concerned that the escalation rates did not reflect current economic conditions in Alberta, and were premised on incomplete data. RPG also submitted that AltaLink's 6.0 percent deviation from the median compensation level was well within the historical norm for utility companies, and should be disregarded.

The AUC held that adjustments to base salary, which are permanent, would not adequately correct for the variance in total direct compensation that is due to non-permanent portions of total compensation. Accordingly, given the current economic climate, the AUC held that this GTA was not the time to correct for perceived market deviations. The AUC noted that the market may move to AltaLink's current total compensation level.

As a result, the AUC held that it would reduce the escalation for 2015 to 2.0 percent. For 2016, the AUC held that, given the current economic climate, a 1.0 percent increase would be reasonable. The AUC directed AltaLink to reflect these figures.

The AUC also denied any increase to executive compensation for both 2015 and 2016, noting that the evidence demonstrated that executive compensation was already 3.0 percent above the market at the beginning of 2015. Accordingly, the AUC directed AltaLink to reduce its executive compensation escalators to 0.0 percent for both 2015 and 2016 in its compliance filing.

AltaLink's short term incentive plan and long term incentive plans were both approved as filed. However as some forecast adjustments made elsewhere in the decision may impact the calculations, the AUC directed AltaLink to recalculate its short term and long term incentive plan amounts in its compliance filing.

<u>FTEs and Vacancy Rates</u>

AltaLink forecasted total operating FTEs of 316 for the 2015 test year, split between 227.4 FTEs for operating and maintenance ("O&M") and 88.6 FTEs for administrative and general ("A&G").

AltaLink proposed a vacancy rate of 2.5 percent, representing the five-year average, consistent with the methodology directed by the AUC in previous GTA applications, and based on its experiences during the 2008 financial crisis.

The UCA submitted that AltaLink's figures for adjusted turnover, and average time to hire were not supported by any analysis, submitting that vacancy rate averages were 4.2 percent for operating FTEs and 10.5 percent for capital FTEs.

The AUC approved AltaLink's forecast FTE's for 2015 as filed, finding them to be reasonable, as the values were similar to AltaLink's previous 2014 compliance filing.

With respect to vacancy rates, the AUC held that the current economic climate may result in a multi-year average not being reasonable. However, the AUC was not persuaded that AltaLink's turnover rates would be as low as forecast. Accordingly, the AUC determined that a vacancy rate of 3.2 percent would be reasonably reflective of the current Alberta economic climate, and directed AltaLink to use this value in its compliance filing.

<u>Operations and Maintenance Expenses</u>

AltaLink applied for the following O&M expenses and A&G expenses for 2015 and 2016:

	2015 forecast	2016 forecast
Labour	48.2	50.1
Contracted Manpower	24.5	24.9
Other GOE	42.5	43.9
Total	**115.2**	**118.9**

AltaLink stated that three factors contributed to its increased O&M costs, which totalled $111.1 million in 2014:

- Aging equipment;
- Increased external requirements; and
- Growth in new assets requiring maintenance.

The CCA did not oppose any specific accounts for operating expenses, submitting instead that it applied an inflation index and composite growth index to O&M costs and A&G expenses, adjusted them for one-time events, externally imposed costs, and converted the figures to constant dollars to reflect levelized growth. The CCA submitted that it used a two-year average O&M base to estimate O&M productivity, and noted a 4.68 percent productivity decrease from 2013-2014 actuals compared with the 2015-2016 forecast values. The CCA therefore recommended reducing AltaLink's O&M costs by $3.8 million in 2015 and $3.9 million in 2016 to offset productivity losses.

AltaLink rejected the CCA's analysis, submitting that the CCA was attempting to impose a performance based regulation ("PBR") formula on to a cost-of-service utility, and further submitted that, once escalators are accounted for, real O&M costs are actually declining over the test period.

While the AUC found that the productivity growth metrics and related evidence from both parties provided some value, it ultimately held that it was not prepared to accept either party's figures. The AUC held that productivity growth metrics are useful as an order of magnitude check on O&M expenses as a benchmarking tool, but noted that:

- There is no standard industry definition or criteria for externally imposed costs;
- There are no generally accepted industry practices for forecasting inflation; and
- There is no consensus on what is the appropriate base from which a productivity measure can be calculated.

With the exception of outside services costs, the AUC accepted AltaLink's forecast costs as filed and subject to its directions with respect to escalation rates. With respect to outside services costs, the AUC held that the forecast increases of $0.5 million in 2015 and $0.3 million in 2016 were not reasonable, as AltaLink had provided no explanation for the increase. The AUC accordingly directed AltaLink to apply the previous 2014 amount of $4.8 million for outside services in its compliance filing.

Depreciation

AltaLink filed a depreciation study with its application, and proposed the following recommendations for its 2015 and 2016 depreciation rates:

- Include forecast capital additions and retirements for 2015 and 2016 in determining annual rates;
- Separate accrual amounts to reflect the amount related to the depreciation of original cost and to the amount for the recovery of future costs in relation to retirement of assets;
- A review of net salvage requirements, consistent with the AUC's determinations in Decision 2011-453; and
- A review of average service life and retirement dispersion rates.

AltaLink's forecast depreciation on rate base was provided as follows:

($ millions)	2015 forecast	2016 forecast
Gross depreciation	144.1	146.6
Amortization of contributions	(4.0)	(7.1)
Amortization of software	16.7	20.8
Depreciation on Rate Base	**153.8**	**160.2**
Depreciation on DACDA	140.4	193.9
Total Depreciation	**294.2**	**354.1**

AltaLink noted that growth in depreciation rates was driven primarily by growth in assets, since its gross plant in service has increased by a magnitude of four times since 2009, with roughly two thirds of the increase being attributable to such growth.

The UCA, and Alberta Direct Connect challenged changes to several of the 15 depreciation study accounts put forth by AltaLink in its depreciation study. The AUC summarized the impact of the proposed recommendations from each group as follows:

($ millions)	2015	2016
AltaLink approved parameters	237.5	292.9
AltaLink proposed parameters	294.2	354.1
UCA proposed parameters compared to AltaLink's proposal	(62.9)	(71.3)

Alberta Direct Connect proposed parameters compared to AltaLink's proposal	(27.0)	(35.0)

AltaLink submitted that it had generated its depreciation parameters, including average service life by comparing itself to a "peer group" of utilities.

The RPG disagreed with AltaLink's choice of peer group, arguing that in many instances, "peers" consisted mainly of utilities for which the expert filing the depreciation study had previously worked for, thus calling into question many opinions expressed in the depreciation study.

The AUC held that peer statistics are useful to gauge the reasonableness of depreciation parameters, but only if sufficient weight can be assigned to the selected peers. The AUC noted that:

- the same analyst filing the depreciation study also prepared studies for AltaLink's selected peer group;
- the degree to which the analyst incorporated his own judgement in this or other depreciation studies was not readily apparent; and
- the group of peer comparators was too small to overcome the two points above. The AUC also noted that some utilities selected were not sufficiently representative of AltaLink's operations, either due to size or location.

Accordingly, the AUC assigned little weight to whether or not AltaLink's proposed parameters were within a peer comparator group.

The AUC held that "gradualism" was a central tenet of utility depreciation regulation, and would help to avoid any significant forecasting errors, which may in turn lead to intergenerational inequity. Accordingly, the AUC provided its findings for each account, using gradualism as a basis for its findings.

The AUC held that AltaLink's proposed changes to its accounts were reasonable. However, the AUC also directed AltaLink to implement subaccounts for depreciation promptly when it has the data and is capable of breaking out subaccounts for new assets, given the large spike in asset growth.

The AUC held that the increase in net salvage values to negative 40.0 percent proposed by AltaLink for transmission station equipment was not warranted. Accordingly, the AUC directed AltaLink to reduce its net salvage percentage to negative 10.0 percent and to account for the impact of this change in its compliance filing. With respect to transmission poles and fixtures, the AUC determined that AltaLink's requested change to net salvage rates of negative 100.0 percent was an unreasonable magnitude of change, and directed AltaLink to apply a net salvage value of negative 53.0 percent in its compliance filing. The AUC also directed AltaLink to maintain the net salvage value of transmission overhead conductors and devices in its compliance filing, at negative 29.0 percent.

With respect to accounts for underground conductors and devices, structures and improvements, as well as power operated equipment, the AUC directed AltaLink to incorporate its previously approved net salvage percentages in its compliance filing.

The remaining net salvage values either remained unchanged or were approved as filed.

<u>Transmission Income Taxes and Revenue Offsets</u>

AltaLink forecasted income tax rates of:

- 15 percent federally in both 2015 and 2016;
- 11 percent provincially in 2015; and
- 12 percent provincially in 2016.

AltaLink sought to include federal and provincial future income tax ("FIT") in its revenue requirement for 2015, and stated that it was not currently taxable in 2016, nor did it expect to be taxable for the foreseeable future.

As a result of AltaLink's submission as to its non-taxable status, it requested an additional 2.0 percent increase to its equity ratio in 2016, which AltaLink submitted as consistent with requests from FortisAlberta, and other Alberta municipal utilities in previous generic cost of capital proceedings.

AltaLink submitted that its proposed inclusion of FIT was a difference in accounting method, and would be revenue neutral to the utility and its rate payers.

The AUC held that AltaLink's forecasted tax rates were substantively enacted, and were approved for use in the compliance filing to this decision. The AUC noted that due to changes to International Financial Reports Standards, that should the Canada Revenue Agency reassess AltaLink's tax filings in the future, the AUC would review the financial implications, and consider what relief, if any, is warranted at that time.

With respect to revenue offsets, AltaLink submitted that it has two main sources of revenue offsets: fixed contracts and variable labour contracts for services provided to affiliates. AltaLink forecasted the following revenue offset amounts for the test period:

($ millions)	2015 forecast	2016 forecast
Affiliates & Inter-Affiliates	1.2	1.2
FortisAlberta Services / Agreements	3.3	3.3
TransAlta Services / Agreements	1.2	1.1
Leases and Other	2.3	2.3
Non-Affiliate Sub-total	6.8	6.7
Total	**8.0**	**7.9**

The AUC noted that no party presented evidence or argument in respect of AltaLink's revenue offsets. However, the AUC noted a discrepancy between two tables projecting revenue offsets in the main application, and in a schedule to the application. As a result, the AUC directed AltaLink to explain the discrepancy in its compliance filing.

Capital

AltaLink submitted that its most up to date forecast of capital costs reflected the following developments:

- Broad changes in Alberta markets, and weak oil prices;
- Actual project costs incurred, as of July 31, 2015;
- Changes arising from AESO additions, delays, deferrals, or cancellations of projects;
- Updated escalation rates;
- Updates to forecast in-service dates from the AESO; and
- Review and update of forecasting uncertainties.

AltaLink submitted its capital cost forecast as follows:

- Capital replacement and upgrade expenses of \$116.8 million in 2015 and \$137.8 million in 2016; and
- Facilities project costs of \$18.3 million in 2015 and \$29.9 million in 2016.

The UCA raised its concerns regarding AltaLink's facilities projects, submitting that it is incumbent on the facility owner to demonstrate that each project is the least cost alternative, and that such facilities would provide a net benefit to customers. Accordingly, the UCA submitted that AltaLink had not provided an explanation for why its expenditures were in the public interest, through a quantitative or net present value analysis. The UCA also submitted that AltaLink understated its facilities costs calculations, by discounting year-zero expenses. The UCA therefore recommended that AltaLink's costs be reduced or recalculated accordingly.

The UCA recommended that the AUC reduce AltaLink's facilities maintenance expenditures by \$1.7 million in each of 2015 and 2016, arguing that a lack of quantitative analysis made it difficult to determine capital versus O&M cost splits, or to examine the necessity of the expenditure in the forecast year.

AltaLink submitted that each of its forecast facilities expenditures would ensure its ability to provide safe and reliable service, noting that its planned projects would assist in avoiding restoration delays in the future, and that such value is not easily captured in a quantitative manner.

The AUC agreed with the UCA in respect of discounting forecasted facilities costs, holding that AltaLink's forecast costs should not use a discount rate for year-zero costs in calculating the net present value of forecast projects.

The AUC also held that AltaLink had not provided adequate explanations for accumulated project variance costs for the AltaLink East Relocation project, which exceeded \$500,000. Accordingly, the AUC reduced AltaLink's project costs by \$500,000, as AltaLink had not provided an adequate explanation of the cost variance.

The AUC also reduced AltaLink's forecast costs for maintenance for its head office by \$0.8 million in each of 2015 and 2016, holding that insufficient information was provided for certain head office maintenance expenditures to justify the forecast expenses.

The RPG opposed AltaLink's proposed capital replacement and upgrade costs, arguing that AltaLink did not appropriately balance cost, safety, reliability and the environment. The RPG submitted that AltaLink's capital replacement and upgrade costs for 2015-2016 increased by 64 percent compared to the average costs between 2005 and 2014, while AltaLink's average system interruption frequency was below the average of its peer group.

The AUC noted AltaLink's lower than average system interruption frequency, but did not find such a fact to be sufficient evidence of excessive replacement spending.

The AUC did express concern regarding the increase in AltaLink's capital replacement spending. Accordingly, the AUC directed AltaLink to explain in its next GTA how it achieves a reasonable balance between cost and reliability in light of its high reliability rating compared to its peers.

The AUC approved AltaLink's capital replacement and upgrade forecast costs as filed.

The AUC directed AltaLink to re-file its 2015 capital additions, holding that AltaLink would have complete and accurate information about the actual amount for direct assign projects brought into service in 2015 by the time the refiling application is brought.

The RPG submitted that for engineering labour, construction labour and materials in capital additions, these costs were within AltaLink's control or were fixed costs. Thus, any costs attributable to project delays should be disallowed, since AltaLink could take steps to enforce its third party contracts.

AltaLink submitted that the RPG was essentially arguing that, in relation to future unknown events, AltaLink should sue its service providers to prevent delays. AltaLink submitted that the RPG's argument was without merit and irrelevant to a GTA.

The AUC dismissed the RPG's recommendation to disallow costs arising from delays, finding that the evidence on the record could not support such a contention.

The AUC approved AltaLink's 2016 forecast capital addition costs of $357 million as filed. However, the AUC noted that if AltaLink has better forecast information at the time of its compliance filing, it is directed to update its 2016 forecast costs as part of its compliance filing using that information.

The AUC approved AltaLink's forecast Control Centre Upgrades Project costs of $2.4 and $2.6 million as filed over the 2015-2016 period.

With respect to information technology ("IT") capital expenditures, AltaLink submitted the following forecast expenses:

($ millions)	2015 forecast	2016 forecast
Hardware	11.0	10.5
Software – SAP	12.2	9.5
Software – non-SAP	11.7	9.8
Total	**34.9**	**29.8**

The AUC determined that it had concerns with the overall level of AltaLink's IT capital expenditures, noting that in 2007, IT capital expenditures were $4.8 million, compared to $34.9 million for 2015.

The AUC held that such an increase in expenses was not supported by any evidence with regard to the benefits accruing from such expenditures, even taking into account the substantial growth in rate base. The AUC noted that although AltaLink had managerial discretion to re-prioritize the timing of expenditures, significant variances from forecast values have persisted year over year. In view of such discrepancies, the AUC directed AltaLink to explain these variances, and what steps AltaLink has taken or will take to address it in its next GTA.

Furthermore, the AUC held that the increased expenditure for SAP software in 2013 and 2014 beyond the approved forecast amounts of $6.1 million for 2013 and $8.8 million for 2014 were not prudent. Accordingly the AUC directed AltaLink to reduce its capital additions for 2013 and 2014 to the approved amounts.

With respect to forecast amounts, the AUC approved forecast amounts of $10.0 million for 2015 and $9.5 million for 2016. These amounts represent the full amount requested save for the CERC project, which the AUC deferred to a later date, noting that AltaLink had not yet proven the business case for the project.

<u>Financing and Transmission Necessary Working Capital</u>

AltaLink submitted that as a result of a new lead/lag study for necessary working capital, it required $0.2 million less per year in its revenue requirement for necessary working capital.

The AUC approved AltaLink's necessary working capital component as filed.

For financing measures, AltaLink proposed, as an alternative to its requested 41 percent equity ratio, incorporating up to $675 million of subordinated debt on a 60-year term into its capital structure, in a similar fashion to ATCO Electric's preferred shares. AltaLink submitted that due to the tax deductibility of interest payments on subordinated debt, the after tax cost of capital with subordinated debt was expected to be lower than only using conventional secured medium-term debt. AltaLink submitted that the treatment of subordinated debt by ratings agencies would result in being given a 50 percent equity credit on the subordinated debt. In AltaLink's view, this would allow AltaLink to reduce its equity ratio to 38 percent from 41 percent, if the AUC were to accept it as an alternative.

Alberta Direct Connect and the UCA opposed the measure in large part because it submitted that subordinated debt was unbalanced, and would increase costs to consumers in the current test period, while not providing any benefit to consumers in future periods.

The AUC held that AltaLink's proposed method of financing was more expensive than debt financing, but was also less expensive than conventional equity financing. As a result, the AUC held that it would provide greater flexibility in financing.

Accordingly, the AUC authorized AltaLink to enter into subordinated debt financing if it consider it to be beneficial. The AUC held that it would determine the cost of such financing in the current generic cost of capital proceeding.

<u>Tariff Relief and Credit Metric Support</u>

AltaLink proposed a number of measures to provide tariff relief in light of the AUC's 2013 generic cost of capital decision, stranded asset risks, and the resulting increased risk of a credit downgrade. AltaLink proposed the following tariff relief measures:

- Discontinue the collection of construction work in-progress ("CWIP") in-rate base amounts effective January 1, 2015;
- Refund previously collected 2011 to 2014 CWIP-in-rate base amounts, to be distributed evenly over 2015 and 2016;
- Discontinue, effective January 1, 2016, the FIT method of collective income taxes and conversion to a flow through method, and a two percent equity increase in 2016; and
- A refund of the accumulated FIT liability in 2016, with the remainder to be refunded in 2017.

AltaLink submitted that the net effect of its tariff relief measures would amount to a reduction of revenue requirement from $858.9 million in 2015 to $694.4 million (a reduction of $164.5 million) and a reduction of revenue requirement from $955.1 million in 2016 to $701.2 million (a reduction of $254.0 million).

AltaLink also submitted that without an amended capital structure, its own credit metrics would fall below the thresholds required to maintain an "A-" level credit rating. AltaLink indicated however that it would only be able to provide its tariff relief if the AUC approved its revenue requirement and equity ratios as proposed, while not significantly changing other amounts, such as depreciation.

The UCA challenged AltaLink's submissions that it was required to maintain a higher equity ratio, with consequential percentage of funds from operations to debt ("FFO-to-debt") of 13 percent. Instead the UCA argued and provided evidence that AltaLink was only obligated to maintain an FFO-to-debt ratio of 10 percent in order to avoid a credit downgrade. The UCA and RPG also noted that none of the ratings agencies have changed their credit ratings for AltaLink.

The AUC determined that the 13 percent FFO-to-debt ratio is not the new required "floor" to maintain an "A-" credit rating. However, the AUC also did not agree with the RPG and UCA that 10 percent FFO-to-debt was an adequate target either.

The AUC held that it would prefer if other credit metric relief support mechanisms be implemented before awarding an increase to a utility's equity ratio. The AUC noted that if AltaLink chose to avail itself of the option to pursue subordinated debt financing, such equity ratio relief would not be necessary at all.

However, the AUC held that it evaluated credit metric proposals using an FFO-to-debt target range of 11.1 to 14.3 percent. Accordingly, the AUC denied AltaLink's proposed equity increase, holding that an increase of three percent to AltaLink's equity ratio to obtain an FFO-to-debt ratio of 13 percent was unnecessary.

With respect to the remaining tariff relief measures, the AUC held that CWIP-in-rate base no longer provides AltaLink with any substantial credit metric relief. Accordingly the AUC directed AltaLink to resume allowance for funds used during construction ("AFUDC") accounting, effective January 1, 2015.

The issue of refunding the CWIP-in-rate base amounts was highly contested. AltaLink submitted that the refund would result in no change to project costs, and would properly allocate the type of assets, locations and years, and would facilitate the proper depreciation of costs for asset classes. AltaLink proposed to refund the CWIP-in-rate base amounts over two years.

The CCA and UCA opposed the refund, arguing that the refund constituted retroactive ratemaking. The City of Calgary, in a similar vein, expressed concern regarding intergenerational equity impacts arising from the refund. The UCA argued that the refund amounted to a high interest loan that will be paid over the next 25 years, was an impermissible exercise in retroactive ratemaking, and did not have the highest net present value when compared to the net present value accounting for the benefits to customers with no refund. The CCA submitted that the refund constituted retroactive ratemaking since the 2011-2014 rates were settled on a final basis, and that parties had no notice that such costs could change.

AltaLink replied that the rates were not final, that the AUC suspended established regulatory accounting principles, but did not permanently change them, and noted further that the refund falls within an exception to the rules against retroactive ratemaking.

The AUC held that in a prospective ratemaking regime, parties are generally entitled to rely on the finality of decisions. However, exceptions to this rule occur when the decision is not final, or if it is interim in nature. The AUC determined that the previous GTA decisions for AltaLink were not interim decisions, and could therefore not be revisited on that basis. Notwithstanding this determination, the AUC also considered whether the manner of approval would enable it to substitute AFUDC for CWIP.

The AUC held that capital projects to which the CWIP-in-rate base were directed to apply had always been subject to deferral account treatment. While the UCA submitted that the purpose of deferral accounts is not to facilitate change in accounting treatment, the AUC found this to be unnecessarily restrictive.

The AUC found that the refund of CWIP-in-rate base did not offend the prohibition against retroactive ratemaking, so long as the project for which the refund would apply were still the subject of direct assign capital deferral account ("DACDA") treatment, which are not yet included in final rates. The AUC determined that the amounts approved on a final basis in Decisions 2013-407 and Decision 2044-D01-2016 would be excluded from this refund, as those costs were approved on a final basis. The AUC therefore directed that AltaLink file an update of the requested refund in Proceeding 3585 in keeping with the determinations made above.

With respect to the discontinuation of FIT amounts, the AUC noted that the consequential equity ratio uplift requested by AltaLink would be considered as part of the ongoing generic cost of capital proceeding. The AUC therefore declined to approve the equity uplift. Accordingly, the AUC also declined to refund the previously collected FIT balances.

No Cost Capital

AltaLink submitted that its forecasted mid-year balance of no-cost capital increased by \$50.6 million in 2015 over the 2014 actual amount and would decrease by \$7.5 million in 2016. AltaLink submitted that the largest factor to changes in no-cost capital balances was the FIT liability account.

None of the interveners in the proceeding raised concerns with AltaLink's proposed no-cost capital figures, including:

- FIT liability balances;
- Self-insurance reserve amounts;
- Hearing reserve amounts;
- Rainbow reserve;
- Pension/post-retirement benefits;
- Deferral accounts, including:
    - Taxes other than income tax;
    - ASP;
    - Direct Assign capital;
    - Long-term debt deferral; and
    - IFRS changes.

Accordingly, the AUC approved the amounts as filed. However, the AUC directed AltaLink to explain and confirm whether transactions processed through its self-insurance reserve account would comply with utility asset disposition principles set out in Decision 2013-413.

Order

In accordance with the above findings, the AUC directed AltaLink to file a compliance filing to reflect the findings, conclusions and directions in this decision on or before July 25, 2016.

E.ON Climate & Renewables Canada Ltd. Grizzly Bear Creek Wind Power Project (Decision 3329-D01-2016)
Facilities – Wind Farm

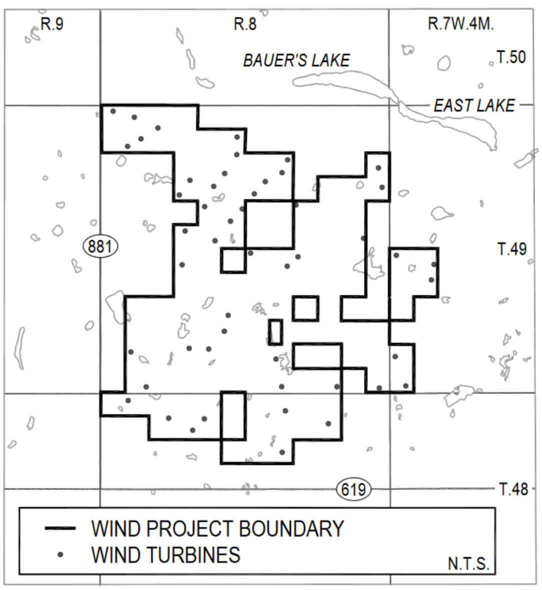
E.ON Climate & Renewables Ltd. ("**EON**") applied to the AUC for the construction and operation of the Grizzly Bear Creek Wind Power Project (the "**Project**"). The Project consists of:

- Fifty 2.4-megawatt (MW) wind turbines, with a total capacity of 120 MW;

- Each tower would be 91 metres tall and have a rotor diameter of 116.8 metes;
- A 34.5-kilovolt (kV) collector system of underground power lines in the Project area; and
- The Grizzly Bear Cree Wind Power Project Substation 708S for future connection to the Alberta Interconnected Electrical System ("**AIES**").

The Project would be located within Township 48, Range 8, west of the Fourth Meridian and Township 49, Ranges 7 and 8, west of the Fourth Meridian, as shown in the following map:

Figure 1 – Grizzly Bear Creek Wind Power Project proposed location



A group of landowners, known as the Grizzly Bear Coulee Projection Group ("**GBCPG**") objected to the Project.

Consultation

EON submitted that it conducted a participant involvement program ("**PIP**"), in accordance with Rule 007: *Applications for Power Plants, Substations, Transmission Lines, Industrial System Designations and Hydro Developments* ("**Rule 7**") to build a relationship with stakeholders potentially affected by the Project. EON submitted that it initially identified stakeholders within 800 metres of the boundary of the Project for personal consultation, and stakeholders within 2,000 metres of the Project for public consultation. EON submitted that it conducted its PIP beginning in April 2012, and included phone calls, distribution of information packages, open houses, and Project update information packages as the Project progressed.

EON submitted that it held three open houses for the Project in April 2013, May 2013, and July 2013. EON also noted that it attended a public information session hosted by the GBCPG in November 2013, and prepared information regarding the health effects of living near wind turbines.

EON submitted that it heard concerns about the siting of its turbines, electric and magnetic fields, shadow flicker, noise, weed control, effects on wildlife, visual impacts, local employment and Project reclamation.

The GBCPG submitted that it had concerns with EON's consultation efforts, specifically related to incomplete project information packages, or misleading information contained in information distributed to stakeholders. The GBCPG submitted that EON should have provided information that was fair, complete and unbiased, which would have resulted in a more fruitful consultation process.

EON disagreed with the assertions that its information was incomplete or biased. EON submitted that the information it provided included peer-reviewed studies, and government-based information. EON contended that the interveners seemed to expect that EON itself should have re-affirmed the interveners' pre-conceived notions of adverse health effects from wind farms. EON submitted that it was not prepared to do so, given the lack of evidence demonstrating any such adverse health effects.

The AUC found that EON had demonstrated that it made reasonable ongoing efforts to address concerns from stakeholders as they arose, and made efforts to include stakeholders that were missed in the initial stages of consultation.

The AUC acknowledged that an effective consultation program may not resolve all concerns, and that individuals may feel that the consultation efforts were not responsive to their specific interests. The AUC held that the divergent views of the consultation process was not an indication of the quality or the effectiveness of EON's PIP, but was simply reflective of the fact that the parties did not agree.

The AUC accordingly held that EON's PIP met the requirements of Rule 7.

Noise

EON submitted a noise impact assessment in support of the application, pursuant to Rule 012: Noise Control ("**Rule 12**"), which sets permissible sound levels of 50 dBA L_{eq} daytime, and 40 dBA L_{eq} nighttime. EON retained experts to provide evidence regarding noise impacts and turbine noise.

EON submitted that its noise impacts assessment was compliant with Rule 12, and further incorporated a number of conservative assumptions, including assuming that each wind turbine would result in downwind propagation of noise to each receptor, and lower ground absorption rates. EON also noted that its turbine models had five sound operating modes to reduce total noise, but based its modelling assumptions on the sound operating modes not being in use.

EON noted that there were 271 third-party facilities in its study area including six large facilities, two satellite well sites, and 263 individual wells. EON opted for a conservative approach using the maximum observed sound level for the third-party wells and applied it uniformly to all 263, and used actual field measurements for the remaining noise sources.

EON submitted that the Project would meet the permissible sound levels, and would verify compliance with Rule 12 through post-construction sound level monitoring. EON recommended that the five receptor locations with the highest nighttime sound levels between 39.9 dBA L_{eq} and 39.8 dBA L_{eq} be used for the post-construction sound level monitoring, since each was within a margin of compliance of 0.5 dBA.

EON further submitted that it could mitigate any further noise impacts through the operating parameters of each wind turbine to fulfill curtailment plans.

The GBCPG questioned the adequacy of EON's noise impact assessments, raising concerns about low frequency noise, infrasound, and vibrations from wind turbines on area residents.

Experts retained by GBCPG agreed with many points on EON's noise impact assessment. However, the experts for GBCPG were of the opinion that the assessment was out-of-date and underestimated third-party noise contribution, and suggested additional fieldwork to ensure that noise emissions from third-parties were adequately quantified. Experts retained by GBCPG also took issue with the noise impact assessment, pointing out that the reports did not explain actual noise impacts on residents, such as impacts on daily activities, or nighttime sleep. Accordingly, GBCPG requested the following requirements for post-construction monitoring, should the AUC approve the Project:

- Post-construction monitoring be done by a third party with results made available to the AUC and local residents, including members of the GBCPG.
- Such monitoring must involve full spectrum monitoring, both inside and outside homes, and must be done with complete transparency of the data to all parties, including residents and local health authorities.
- The monitoring should be made available to any local residents, including members of the GBCPG who request it.
- E.ON substitute dB Lin, or dB linear, for dBC in the post-construction comprehensive noise study that it has committed to do and that the post-construction comprehensive noise study include infrasound and low frequency noise measurements inside some of the local residents' homes.
- The monitoring system should be done in real time and with built-in shutdown mechanisms for when either accepted noise limits are exceeded or when noise nuisance is repeatedly occurring to the residents with a built-in facility for change. As the residents become increasingly sensitized to the pulsing infrasound and low frequency noise, over time, they would therefore need lower and lower limits in order to protect their sleep.

The AUC held that the noise model used by EON met the standards identified in Rule 12, and applied appropriately conservative assumptions. The AUC held that EON's noise modeling did not require and upward or downward adjustments for the purposes of the noise impact assessment, and rejected the adjustments proposed by the GBCPG.

The AUC determined that the predicted sound levels from the Project were in compliance with the daytime permissible sound levels in Rule 12, and nighttime permissible sound levels, provided that specific turbines were operated in sound reducing operating modes. Accordingly, the AUC directed that turbines 22 and 23 in the Project be operated in sound reducing operating modes during nighttime periods.

The AUC included a number of conditions in providing its determination on noise issues. The AUC included conditions relating to the operation of specific turbines in sound optimized modes during nighttime, and required a post-construction noise assessment at six receptor locations, including the locations proposed by EON.

<u>Health</u>

The GBCPG expressed concerns about living in close proximity to wind turbines, including concerns related to audible noise, low frequency noise, and infrasound, as well as shadow flicker and light pollution. Many other GBCPG members also expressed concerns about impacts on lack of sleep caused by the proximity of the wind turbines. The GBCPG pointed to a decision in respect of the Shirley Wind Farm by the Brown County Board of

Health, which it submitted declared a wind project as a human health hazard.

The GBCPG submitted that compliance with Rule 12 would not be sufficient to protect nearby residences from health impacts. The GBCPG provided expert testimony that a study conducted on 38 individuals who lived within 1,500 meters of a wind turbines, and examined impacts on sleep quality based on distance from wind turbines. The GBCPG report concluded that sleep quality improves, and sleep impacts decline as distance from a wind turbine increases, with little impacts noted beyond 1,400 meters. Accordingly, the GBCPG submitted that there was a high probability of significant adverse health effects for residents located within 1,400 meters of any of the proposed turbines from the Project.

EON submitted that the Project would not adversely affect the health of nearby residence. EON pointed to studies conducted by Health Canada which concluded that there is no evidence of an association between exposure to wind turbine noise and the prevalence of self-reported or measured heath effects, beyond annoyances, at wind turbine noise levels of up to 46 dBA. EON submitted that the conclusion arrived at by Health Canada supported the conclusion that the Project would not cause adverse health effects, given the results of the noise impact assessment.

The AUC determined that the evidence provided by both parties indicated that audible noise from wind turbines at or above a certain level and distance could be associated with sleep disturbance and annoyance, both of which can lead to adverse health impacts. However, the AUC noted that both parties disagreed on the sound level and distance at which these impacts occur.

The AUC rejected the recommendations of the GBCPG, on the basis that the areas studied were not comparable to the Project, and noted that the increased levels of sleep disturbance and health impacts occurred at levels above 40dBA. Accordingly, the AUC found that the recommendations of the GBCPG did not reflect a reasonable interpretation of the other available scientific evidence.

The AUC held that it preferred the Health Canada study provided by EON, noting that it included a large sample size of residences near wind turbines (and others located up to 11 kilometers away) with over 1200 participants. The AUC noted that the only statistically significant impact determined in the Health Canada study was that blinking lights placed on top of individual turbines would result in an annoyance, and impacted sleep time. The AUC accepted the conclusions arrived at in the Health Canada study, including that self-reported diagnosed sleep disorders and high sleep disturbance was unrelated to wind turbine noise below 46 dBA.

Accordingly, the AUC held that there was no persuasive evidence that the Project would likely result in adverse health effects on nearby residents.

However, with respect to low frequency noise and infrasound, while the AUC determined that health impacts arising from these sources were unlikely, the AUC directed EON to conduct post-construction monitoring for low frequency noise and infrasound levels. The AUC held that, should such post-construction monitoring reveal a low frequency noise condition, EON must mitigate such noise in compliance with Rule 12.

<u>Property Impacts</u>

The GBCPG submitted that the visual impacts and number of turbines in the Project would negatively impact land values. GBCPG members also expressed concerns about the spread of noxious weeds during construction activities, and resulting impacts on agricultural land use. GBCPG members also expressed concerns that they would no longer be able to employ aerial spraying for crops, due to the presence of the wind turbines.

EON submitted that visual impacts are inherently subjective, noting that pre-existing disturbances are present in the Project area, including pump stations, well compressor stations and other oil and gas facilities.

EON submitted that the impacts on property values were not supported by evidence, and noted that most major studies did not find evidence that wind turbines decreased property values. EON also submitted that none of the Project turbines would be located on land owned by GBCPG members.

With respect to agricultural land impacts, EON submitted that it would wash equipment prior to entering on Project lands to prevent the spread of noxious weeds. EON also submitted that aerial spraying concerns were not supported by evidence in the proceeding, however it did commit to working with landowners to accommodate the usage of aerial spraying if the need arises.

The AUC held that visual impacts are subjective in nature, and recognized that the construction and operation of the Project would change the landscape of the project area. However, the AUC noted that the extensive disturbance from oil and gas development in the area was a factor to be taken into consideration.

The AUC held that there was insufficient evidence provided to show that land use would be impacted by the Project, and accordingly the AUC could not conclude that the Project would result in any adverse impacts on property values or agricultural impacts.

Environmental Impacts

EON submitted that the Project area is comprised of cultivated cropland (67 percent), modified pasture (9.1 percent), wetlands (9.2 percent), hay land (6.4 percent) and trees/shrubs (6.0 percent) as well as smaller portions of farmyards (1.9 percent), native pasture (0.2 percent), and dugouts (less than one percent). EON submitted that the Project area did not contain any provincially or federally designated protect areas, Environmentally Significant Areas ("ESA") or National Wildlife Areas.

EON submitted that it identified 1,718 wetlands in the Project area, mainly as class III and class IV wetlands (which are seasonal and semi-permanent wetlands). EON submitted that the Project had limited potential to alter the hydrology and topography of the area, and that wetland avoidance would be the primary mitigation technique employed during construction and operation.

EON noted that due to heavy agricultural development, much of the native vegetation had been modified or removed, resulting in no listed plant species being recorded during its site surveys, and minimal impacts on wildlife habitat. However, EON committed to post-construction monitoring of the Project for any impacts or effects on bat mortality, noting that its surveys indicated bat mortality risk as potentially moderate during certain conditions. EON also submitted that it had received sign-off from Alberta Environment and Parks ("AEP").

The GBCPG submitted that the Project would adversely impact wildlife in the area, and submitted that deer, waterfowl, bats, geese, pelicans, blue herons, owls and other migratory birds frequented the Project area. The GBCPG noted that there is an ESA located adjacent to the Project, which may require special considerations due to biodiversity conservation needs. The GBCPG also raised concerns that bat surveys had not been conducted by EON since 2012.

The GBCPG recommended that any approval for the Project should be conditional upon a mitigation framework being established for waterfowl, as well as bats. The GBCPG also recommended that construction occur outside the period of January 15 to April 30 to reduce impacts on wildlife.

The AUC held that the siting of individual turbines on cultivated lands would reduce the potential for adverse environmental impacts, since the lands are pre-disturbed. The AUC held that the sign-off from AEP indicated that the impacts to the environment and on wetlands were acceptable to AEP. The AUC therefore concluded that the siting of the individual turbines was reasonable in the circumstances.

The AUC noted that EON filed bat and bird surveys, however, the AUC noted that the surveys were conducted more than two years prior to the application being filed. Accordingly, the AUC directed EON to conduct pre-construction surveys for wildlife and bat migration, as well as post-construction surveys and monitoring plans for any impacts on wildlife.

Order

The AUC held that, taking into account the negative effects of the Project, which include visual impacts, noise, annoyance and impacts on the environment, any impacts created due to the construction and operation of the Project could be mitigated to an acceptable degree. The AUC determined that, with appropriate mitigation measures, the positive benefits of the project outweigh its negative impacts. Accordingly, the AUC held that the Project would be in the public interest.

The AUC accordingly approved the Project, on the following conditions:

- EON shall operate turbines 22 and 23 in sound optimized modes during the nighttime period to ensure compliance with the nighttime permissible sound level.
- EON must ensure that all noise mitigation measures proposed in the application are implemented, to ensure compliance with the permissible sound level at all receptor locations in the study area. The noise control measures proposed in the application included: maintaining the equipment so it is running correctly, implementing wind turbines in sound optimized mode, applying mitigation on third-party energy-related facility noise sources, or the shutting down of wind turbines.
- EON shall:
  - (a) Conduct a post-construction comprehensive noise study, including an evaluation of low frequency noise, at six receptors under representative conditions, in accordance with Rule12.
  - (b) File all studies and reports relating to the post-construction comprehensive noise study with the AUC within one year of connecting the power plant to the Alberta system.
- If the Project encroaches upon newly identified wetlands, the applicant must re-site the offending Project component(s) or receive AEP's approval to site the Project within the wetland setback.

- EON shall conduct a pre-construction spring wildlife survey, which will include birds and amphibians, within two years from the start of construction.
- EON shall conduct a pre-construction fall bat migration study, within two years from the start of construction.
- EON shall develop a post-construction monitoring plan in consultation with AEP. Post-construction follow-up surveys will be completed over a minimum of two years to determine changes to bird and bat use of the areas associated with turbines and related infrastructure. A detailed report of the post-construction monitoring will be provided to AEP annually.
- EON shall develop and implement an environmental protection plan in consultation with AEP.
- EON shall use the minimum number of lights required by Transport Canada on the turbines, and set these lights to the minimum number of synchronized flashes per minute and the minimum flash duration.

EPCOR Distribution & Transmission Inc. Disposition of Substation Property (Decision 21405-D01-2016)
Facilities – Rate Base – Disposition

EPCOR Distribution & Transmission Inc. ("EDTI") applied for approval to dispose of Substation No. 450, located at 11803 – 114 Avenue Northwest in Edmonton, Alberta (the "Property"), pursuant to section 101(2)(d) of the *Public Utilities Act*.

EDTI submitted that the Property was placed into service in 1950, and due to the average service life for depreciation, all of the assets had been removed from rate base as of 1995. EDTI submitted therefore that all of the assets in question were fully depreciated and that they were retired from the accounting records at the end of their average service lives. EDTI noted that this retirement occurred prior to the physical retirement of the assets from electric distribution service.

EDTI submitted that the reason for its requested disposition of the Property was due to the Property's configuration with 5-kV equipment, which is no longer standard, and not supported by the manufacturer any longer. EDTI submitted that in 2013 and 2014 its 5-kV feeders were converted to 15-kV substations. As a result, the Property was no longer required for the provision of utility service by EDTI. EDTI proposed to remove the book value of the land from rate base on December 31, 2017, at the end of its current performance based regulation ("PBR") term.

EDTI submitted that the fair market land value of the Property was approximately $730,000 with estimated net proceeds of $530,000, and that no environmental remediation work would be required at the Property, after performing environmental site assessments.

EDTI submitted that its proposed disposition occurs outside the ordinary course of business (as it had only disposed of six properties outside the normal course of business since 2006 – three of which were substations), and therefore required AUC approval. EDTI further submitted that the estimated market proceeds of $730,000 was material.

The AUC held that the proposed disposition would occur outside the ordinary course of business, since utilities are not in the business of acquiring and divesting real estate.

The AUC determined that the proposed disposition of the Property was material, noting its prior determinations on materiality for EDTI's dispositions in Decision 3206-D01-2015, which had approved $500,000 as material for the purposes of a disposition outside the ordinary course of business.

EDTI submitted that the proposed disposition would not harm ratepayers, as the disposition would result in a small reduction in operating costs borne by rate payers, and reiterated that the Property was no longer needed to provide reliable service to customers. EDTI also noted that ratepayers would not see any rate impacts due to the disposition, since costs and revenues are decoupled during the current 2013-2017 PBR term.

The AUC held that since the Property was no longer required for the provision of utility service, the proposed disposition would not have any effect on the quality and quantity of utility service. The AUC also held that there would be no financial harm to ratepayers, since rates would not be impacted by the disposition, and noted that ratepayers will not bear any costs arising from the disposal of the Property.

The AUC held that it would not require EDTI to make any adjustments or remove land from rate base prior to the expiry of the current PBR term, since the impact would be largely immaterial. The AUC also noted its previous holdings in Decision 2012-237 that adjustments to going-in rates are not to be made to reflect actual events during the PBR term. Therefore the AUC directed EDTI to remove the book value of the land from its rate base, effective December 31, 2017.

The AUC held that all net proceeds of sale and any net gains from the sale are to be for the account of utility shareholders, and directed EDTI to provide confirmation of the net proceeds of the disposition and include its proposed rate adjustment for the disposition of the Property at the time of its next revenue requirement application.

Accordingly, the AUC approved the sale of the Property, as filed.

AltaGas Utilities Inc. Compliance Filing to Decision 20522-D02-2016 (2014 Capital Tracker True-Up and 2016-2017 Capital Tracker Forecast) (Decision 21380-D01-2016)

Capital Tracker – Rates – True-Up

AltaGas Utilities Inc. ("AltaGas") filed its compliance filing with the AUC pursuant to directions issued in Decision 20522-D02-2016.

Direction 1 and 3

The AUC directed AltaGas to calculate and include the revenue requirement for four projects in its Pipeline Replacement program in 2013, on a mid-year basis, in its performance based regulation ("PBR") rate adjustments for its K Factor amounts. The AUC also directed AltaGas to calculate and include the revenue requirement for two projects in its Station Refurbishment program in 2013, on a mid-year basis.

AltaGas submitted that the revenue requirement adjustment for the four Pipeline Replacement projects resulted in a $9,845 refund to customers. AltaGas submitted that the revenue requirement adjustment for the two Station Refurbishment projects resulted in a $1,372 refund to customers.

The AUC held that AltaGas had complied with Directions 1 and 3.

Directions 2 and 5

The AUC directed AltaGas to provide project-level trailing cost explanations for certain 2012 and 2013 projects in the Pipeline Replacement program. The AUC also directed AltaGas to provide project-level variance explanations for its Gas Supply program for two projects' trailing costs.

AltaGas submitted that it provided trailing cost explanations for each project, as directed by the AUC.

The AUC held that AltaGas had complied with Directions 2 and 5.

Direction 4

The AUC directed AltaGas to correct a coding error that was discovered by AltaGas during proceeding 20522, which had misallocated $20,290 of trailing costs for 2012 to the incorrect project in its initial application.

AltaGas submitted that it had corrected the coding error, and that the impact on rates in 2014 and its 2016-2017 forecast were negligible, at less than $600.

The AUC held that AltaGas complied with Direction 4, and found that the impact on rates from 2014 onward (although it recognized that 2015 rates were out of scope for this proceeding) were reasonable. Accordingly, the AUC approved the amended amounts, and noted that AltaGas would include the adjusted rate impact for 2015 in its upcoming 2015 capital tracker true-up application.

Directions 6, 8, and 12

The AUC directed AltaGas to use the approved 2016 I-X index and forecast billing determinants as approved in Decision 20823-D01-2015. The AUC directed AltaGas to update its accounting tests for capital tracker treatment based on final forecast or actual capital additions approved in Decision 20522-D02-2016.

The AUC also directed AltaGas to update the 2016 and 2017 forecast amounts of $5,854,585 and 8,483,831, respectively, in its compliance filing to give effect to:

- The 2016 I-X index and the Q factor figures approved in Decision 20823-D01-2015; and
- The revised gas supply placeholder as calculated in Decision 20522-D02-2016.

AltaGas submitted that the 2016 K Factor adjustment, taking into account the above directions, was reduced from $5,854,585 to $5,796,653. AltaGas submitted that the 2017 K Factor adjustment, taking into account the above directions, was reduced from $8,483,831 to $8,297,204,

The AUC held that AltaGas correctly applied the approved 2016 I-X index and forecast billing determinants in compliance with Direction 6. The AUC also held that AltaGas correctly applied and updated the accounting tests in accordance with Direction 8.

Directions 9 and 10

The AUC directed AltaGas to re-calculate its materiality threshold tests for capital tracker treatment to reflect the changes to the accounting test in Directions 6, 8 and 12. The AUC also directed AltaGas to re-assess whether its projects proposed for capital tracker treatment meet the thresholds for capital tracker treatment using the re-calculated materiality thresholds.

AltaGas submitted that the materiality test thresholds for 2016 were updated as follows:

- A four basis point threshold of $32,580;
- A forty basis point threshold of $325,802.

AltaGas submitted that the materiality test thresholds for 2017 were updated as follows:

- A four basis point threshold of $32,873;
- A forty basis point threshold of $328,734.

AltaGas submitted that each of its programs and projects proposed for capital treatment exceed the revised materiality figures.

The AUC held that AltaGas had correctly updated its materiality threshold tests, and that each of its proposed programs and projects exceeded the threshold for capital tracker treatment. Accordingly, the AUC held that AltaGas had complied with Directions 9 and 10.

Direction 14

The AUC directed AltaGas to file with the AUC evidence of its reconciliation of capital cost allowance amounts filed with the Canada Revenue Agency.

The AUC held that AltaGas had complied with Direction 14.

Order

The AUC accordingly ordered that AltaGas' 2013, 2014, 2016 and 2017 K Factor adjustments applied for were approved.

The AUC noted that AltaGas would address the remaining directions in future PBR rate applications.

NATIONAL ENERGY BOARD

National Energy Board Establishes Joint Committee on Pipeline Safety with Industry Association (May 25, 2016)
Safety – Pipelines

The NEB announced it had struck a Joint Committee on Issues of Mutual Interest for Federally Regulated Pipelines (the "Joint Committee") with the Canadian Energy Pipeline Association ("CEPA"). Senior leadership from both the NEB and CEPA will co-chair and participate in Joint Committee meetings.

The NEB noted that the purposes of the Joint Committee are to:

- Exchange information and ensure proactive issue identification on topics of mutual interest to the NEB and CEPA.
- Discuss and prioritize opportunities such as:
    - Company management systems audits and simplification;
    - CEPA Integrity First implementation;
    - The advancement of safety culture across the pipeline industry;
    - Development of processes and lines of communication between the NEB and CEPA for the purposes best practices information exchange, regulatory efficiencies, and regulatory policy development; and
    - Common approaches to align pipeline safety indicators.

The Joint Committee's three-part mandate includes collaborative work on Operational Matters, Regulatory Process, and Lifecycle Issues.

National Energy Board Report - Trans Mountain Expansion Project (Hearing Order OH-001-2014)
Facilities – Pipeline

The NEB released its recommendation to the Governor in Council ("GIC") for the recommendation to approve the Trans Mountain Pipeline ULC ("Trans Mountain") application for the Trans Mountain Expansion Project ("Project"), subject to 157 conditions.

Trans Mountain applied for an expansion of its existing Trans Mountain Pipeline system from Edmonton, Alberta to Burnaby, British Columbia. Trans Mountain stated that crude oil delivered to Burnaby would be loaded onto tankers at the Westridge Marine Terminal ("WMT") for export to areas such as Washington, California, or other markets throughout Asia. Trans Mountain proposed to twin the existing Trans Mountain Pipeline System as follows:

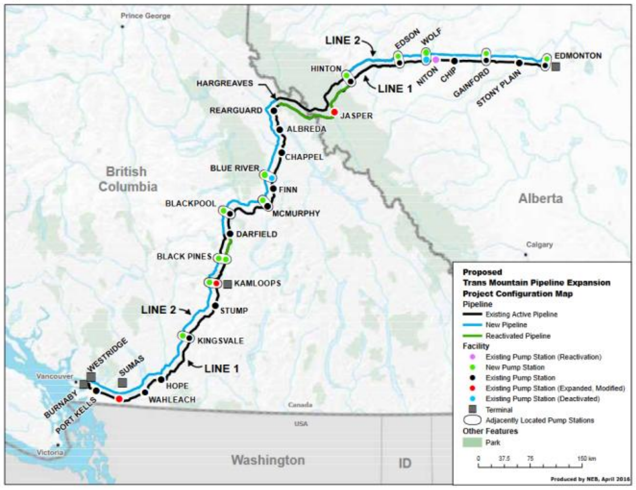
- Line 1 – consisting of most of the existing pipeline segments, along with two reactivated pipeline segments; and
- Line 2 – consisting of mostly new pipeline segments, along with two currently active pipeline segments.

Trans Mountain submitted that the Project would consist of approximately 987 kilometres of new buried pipeline. The Project would increase the capacity of the existing Trans Mountain Pipeline system from approximately 47,690 cubic metres per day (or 300,000 barrels/day) to approximately 141,500 cubic metres per day (or 890,000 barrels/day) of crude petroleum and refined products.

Trans Mountain also noted that the tanker traffic at the WMT would increase from approximately five Panamax class tankers per month (with a capacity of 75,000 metric tonnes of deadweight tonnage each) to approximately 34 Aframax class tankers per month (with a capacity of 80-120,000 metric tonnes of deadweight tonnage), depending on market demand.

The Project route was provided in a figure by the NEB in the decision, as follows:

Figure 1: Project map



Trans Mountain stated that it selected its preferred route using the following criteria:

- siting the proposed corridor on, or adjacent to the existing pipeline or adjacent to easement or rights of way of other linear facilities;
- siting the proposed corridor in a new easement selected to balance a number of engineering, construction, environmental and socio-economic factors; and
- minimizing the length of any new easement before returning to the existing pipeline easement or other rights of way.

Trans Mountain noted that the Project would traverse a number parks and protected area in British Columbia: Finn Creek Provincial Park, North Thompson River Provincial Park Lac Du Bois Grasslands Protected Area, and Bridal Veil Falls Provincial Park. In Alberta, Trans Mountain noted that the route would traverse Jasper National Park.

Trans Mountain noted that the proposed route would primarily cross private lands (73.50 percent), and Crown lands (25.71 percent) followed by Aboriginal tracts of land (0.80 percent).

<u>Benefits, Burdens and the NEB Recommendation</u>

The NEB provided a summary table of benefits and burdens associated with the Project in its summary of its recommendation. The NEB noted the following:

Benefits	**Description**	**Type of Impact**
Market Diversification	There would be a considerable benefit gained by providing shippers with more flexible and diverse markets, including the ability to manage development and operational risk, and a likely reduction to discounts to Canadian crude.	Regional National
Jobs	There would be a considerable benefit in terms of jobs created, including: • Pipeline construction – 400-600 workers per spread • Tank Construction – 60-370 workers • WMT construction – 95 workers • 443 Jobs per year over the first 20 years of operation (313 in British Columbia, 130 in Alberta)	Local Regional National
Competition Among Pipelines	There would be a considerable benefit from the increase in flexibility and optionality for producers getting product to market, likely benefiting all western Canadian producers in the long term.	Regional National
Spending on Pipeline Materials	There would be considerable benefit to local and regional economies from direct spending on pipeline materials where the Project is located.	Local Regional
Community Benefit Program	There would be a modest benefit to local communities and the environment in establishing a Community Benefit Program, including: Local emergency management capacity enhancements Improvements to community parks and infrastructure Support for events and educational programs Environment Stewardship Program	Local Regional

Enhanced Marine Spill Response	There would be a modest benefit from enhanced marine spill response planning for responding to spills from vessels not associated with the Project.	Local Regional
Capacity Development	There would be a modest benefit from local economic and educational opportunities, and the development of capacity of local and Aboriginal individuals, communities and businesses.	Local Regional
Government Revenues	Direct Project expenditures would likely result in considerable revenues to various levels of government.	Local Regional National
Burdens	**Description**	**Type of Impact**
Southern Resident Killer Whales	The operation of Project-related marine vessels would likely result in significant adverse effects to the Southern resident killer whale. The NEB noted that although the Project effects are a small fraction of cumulative effects, the increase in vessel traffic would further contribute to cumulative effects and further jeopardize the recovery of the Southern resident killer whale.	Local Regional National
Aboriginal Culture Use Associated with Southern Resident Killer Whales	The operation of Project-related marine vessels would likely result in significant adverse effects on Aboriginal cultural use associated with Southern resident killer whales.	Local Regional
Marine Greenhouse Gas Emissions	The greenhouse gas emissions from Project-related marine vessels would likely be significant. The NEB noted that there are no regulatory requirements for marine greenhouse gas reporting thresholds, and that the modelled emissions would result in measurable per cent increases.	Regional National
Municipal Development Plans	The Project may pose a modest burden on municipalities by potentially constraining future plans for municipal development.	Local
Aboriginal Groups' Ability to Use the Land and Water	There would be modest burdens sustained by Aboriginal groups as their ability to use the lands, waters, and resources for traditional purposes would be temporarily impacted by construction and routine maintenance activities. The NEB found that the activities affected by the WMT would persist throughout the operational life of the Project. The NEB determined that while these effects would be long term in duration, they would be reversible and would be confined to the water lease boundary for the WMT.	Local
Landowners' and Land Users' Ability to Use the Land and Water	There would be modest burdens sustained by landowners and land users as their ability to use the land and water would be affected by construction and routine maintenance activities during operations, and may cause nuisance disturbance, such as noise.	Local
Project Spills	The NEB found that there was a very low probability of a Project spill that may result in a significant effect. The NEB therefore determined that the risk of a spill was acceptable.	Local Regional
Spill from a Project-Related Tanker	The NEB found that there was a very low probability of a marine spill from a Project-related tanker that may result in a significant effect. The NEB therefore determined that the risk of a spill was acceptable.	Local Regional

The NEB noted that in weighing the benefits and residual burdens of the Project that it placed significant weight on the economic benefits of the Project, many of which would be realized throughout Canada. The NEB noted that such a national perspective was critical in the NEB's finding that the Project would be in the Canadian public interest.

The NEB found that the Project was in Canada's public interest, and recommended that the GIC approve the Project, and direct the NEB to issue the necessary certificates of public convenience and necessity (“CPCN”).

Regulating through the Project Lifecycle

The NEB noted that if the Project is approved and Trans Mountain proceeds with the Project, it would be required to comply with all conditions included in the CPCN and associated instruments.

Among the conditions imposed by the NEB, during the construction phase, Trans Mountain must have qualified inspectors on site to oversee construction, and have the NEB conduct field inspections.

Trans Mountain would also be required to apply for leave to open the Project under section 47 of the *NEB Act*.

The NEB also imposed conditions during the operations phase of the Project, and required Trans Mountain to restore its rights of way and temporary work areas to a condition similar to the surrounding environment, as well as monitor the rights of way for any environmental issues created from construction and operation. The NEB further imposed as a condition that it would inspect the Project post-construction to verify compliance with conditions imposed.

With respect to compliance verification and enforcement, the NEB stated that its conditions and compliance programs were designed to ensure the safe and effective environmental protection throughout the lifecycle of the Project.

The NEB explained that it applies a risk-informed approach in planning compliance and verification activities, evaluating facilities on an ongoing basis to determine the appropriate compliance verification activities.

Public Consultation

Trans Mountain submitted that its Stakeholder Engagement Program (“SEP”) was designed to foster participation from the public who have an interest in the Project. Trans Mountain submitted that it consulted with local governments and community leaders to seek input for its SEP in 2011. Trans Mountain stated that it identified a number of stakeholder groups that could be interested in the Project, including landowners, government authorities, industry and businesses, environmental non-governmental organizations, special interest groups, as well as the general public as part of its SEP. Specific to the WMT, Trans Mountain submitted that it extended its stakeholder consultation efforts to include coastal communities beyond the WMT in Burnaby, BC.

Trans Mountain submitted that its SEP was conducted beginning in 2012, and is an ongoing process, including open houses, community workshops and online discussion activities, as well as face-to-face meetings, presentations, public forums and technical meetings. Trans Mountain stated that its activities included:

- 159 open houses along the pipeline and WMT corridor;
- 1,700 meetings between Project team members and stakeholder groups;
- 550 phone inquiries, and approximately 1,500 emails,
- Approximately 950 media inquiries and 430 media interviews.

Trans Mountain further noted that various documents were made available in multiple languages, including French, Chinese, Punjabi and Korean to ensure its communications reached as broad an audience as possible.

Trans Mountain submitted that it incorporated stakeholder feedback as part of its SEP by, for example, making the following changes to the design of the Project:

- Exploring alternatives to avoid the use of temporary work spaces in Colony Farm Regional Park;
- Establishing access planes, construction schedules and compensation plans to minimize impacts on the Ledgeview Golf Course;
- Implementing horizontal directional drilling (“HDD”) entry and exit points more than 30 metres away from watercourse and riparian areas; and
- Assigning community construction liaison roles as part of its construction team as a key point of contact for local communities.

The City of Abbotsford, Township of Langley, Fraser Valley Regional District, Fraser-Fort George Regional District & Village of Valemount (the “Municipalities”) expressed concerns regarding consultation, including a failure to communicate and incorporate feedback on important matters that would impact the Municipalities. The Municipalities also stated that Trans Mountain had not fully recorded all of the commitments made to them.

Trans Mountain replied stating that it maintained regular engagement with governmental entities, and would continue to do so to address specific municipal issues and concerns through joint technical working groups.

The NEB held that Trans Mountain developed and implemented a broadly based SEP, offering numerous opportunities for stakeholders to provide their views on the Project.

The NEB stated that it expected parties to engage by communicating their concerns to one another and to make themselves available to discuss potential solutions on an ongoing basis. The NEB noted in particular that the City of Burnaby declined a number of opportunities to meet with Trans Mountain, and held that when a municipality declines an opportunity to engage, it effectively diminishes the quality of information available both to the company proposing a facility, and the NEB itself, creating a potential for less than satisfactory solutions to stakeholder concerns.

The NEB imposed a condition on Trans Mountain to require that it establish terms of reference for its technical working groups in collaboration with affected municipal government, facility owners and operators prior to commencing construction. The NEB also imposed a condition requiring Trans Mountain to file with the NEB reports of the meetings of the technical working groups, allowing the NEB some visibility into how Trans Mountain is addressing stakeholder concerns on an ongoing basis.

The NEB further imposed a condition requiring the tracking of commitments prior to the start of construction, and to file the same with the NEB.

Taking into account the above conditions, and Trans Mountain's commitments to stakeholders, the NEB held that Trans Mountain can effectively engage the public, landowners and other stakeholders, and address any issues raised throughout the life of the Project.

<u>Aboriginal Matters</u>

Trans Mountain stated it viewed working with Aboriginal communities along the Project route as part of its commitment to transparent consultation and communication, and would build lasting and mutually beneficial relationships.

Trans Mountain submitted that its Aboriginal consultation program commenced in 2012, and remains ongoing. Trans Mountain stated that it consulted with Aboriginal groups within a 10-kilometer radius around the Project area for consultation in British Columbia, and a 100-kilometer radius in Alberta (due primarily to uncertainty with the establishment of traditional territories).

Trans Mountain also extended its Aboriginal engagement program to include coastal communities beyond the pipelines terminus at the WMT, including communities on Vancouver Island and surrounding Gulf Islands along the established marine shipping corridors. Trans Mountain submitted that it engaged in consultation with 120 Aboriginal groups, two non-land based British Columbia Métis groups, and 11 Aboriginal associations, councils and tribes.

Trans Mountain stated that it focused on enhancing trusting and respectful relationships, and its consultation activities included:

- Sharing Project information;
- Negotiating group and community-specific protocols, capacity agreements, and mutual benefit agreements;
- Facilitating traditional land use ("TLU") studies and traditional marine resource use ("TMRU") studies, as well as traditional ecological knowledge ("TEK") studies;
- Identifying potential impacts and addressing concerns;
- Discussing the adequacy of planned impact mitigation; and
- Identifying education, training, employment and procurement opportunities.

Trans Mountain estimated that it completed more than 24,000 engagement activities with Aboriginal groups. Trans Mountain noted that its engagement process varied from group to group, as some preferred open processes, whereas others preferred strictly confidential meetings.

Trans Mountain submitted that as a result of its engagement activities, it identified air and water quality, fish and fish habitat, wetlands, vegetation, wildlife and wildlife habitat and species at risk impacts that required addressing. A total of 52 Aboriginal communities participated in TLU studies, 15 Aboriginal communities participated in TMRU studies, and 57 Aboriginal communities provided TEK studies.

Trans Mountain also noted it received a total of 30 letters of support from Aboriginal groups, and executed 94 agreements including letters of understanding, with an aggregate value of $36 million.

A total of 24 Aboriginal groups filed evidence and raised concerns regarding the engagement process, Project benefits, emergency response planning, capacity funding, and Project-related effects on the assertion of Aboriginal rights and title. Many of the groups submitted that Trans Mountain did not adequately discuss mitigation measures, or failed to formalize commitments, and that Trans Mountain did not consult with them until the group itself advised Trans Mountain of its concerns.

The Government of Canada submitted that it would rely on the NEB's review process to the extent possible to identify and consider and address any adverse impacts on potential or established Aboriginal and treaty rights resulting from the Project.

The Government of Canada outlined its approach to consultation in four phases:

- Phase I: Initial engagement, ranging from submission of Project description to the start of the NEB review process;
- Phase II: NEB hearings;
- Phase III: Post-NEB hearings to a Governor in Council decision on the Project; and
- Phase IV: Regulatory permitting, ranging from the Governor in Council decision, to the issuance of any required approvals.

The Government of Canada noted that its federal authorities would work together to ensure that the legal duty to consult Aboriginal groups is fulfilled and performed in a manner that is integrated with its other assessments and reviews for the Project.

The NEB held that while it does not owe a duty to consult itself, it recognized that the Government of Canada was relying on its processes to meet its own duties to consult, given the NEB's robust and inclusive process, and remedial powers. The NEB determined that it was satisfied that its decisions and recommendations were consistent with section 35(1) of the *Constitution Act, 1982* regarding the duty to consult with Aboriginal groups.

In assessing the interests of each group that may be impacted, the NEB looked to the measures that could be employed to mitigate each group's concerns, and then considered all of the benefits and burdens of the Project as a whole, balancing Aboriginal concerns with other interests and concerns before determining whether the Project was in the public interest.

The NEB held that Trans Mountain met the expectations of the NEB's filing manual, including information about the Project's design, operations and potential environmental, social and economic effects. The NEB found that the criteria used by Trans Mountain to identify potentially affected Aboriginal groups were appropriate in considering their proximity to the proposed right of way of the Project. The NEB held that Trans Mountain provided opportunities to Aboriginal groups to raise and discuss the potential impacts of the Project with Trans Mountain. The NEB further found that Trans Mountain considered information provided by Aboriginal groups throughout consultations, and made a number of changes to the Project as a result of this information, including reconfiguring the proposed route in the Upper Fraser River, Upper North Thompson River Valley, and the Peters Indian Reserve No. 1A.

The NEB imposed conditions on Trans Mountain requiring them to file with the NEB, a plan for monitoring the implementation of training and education opportunities, and to file a local, regional and Aboriginal skills and business inventory with the NEB.

As the NEB found that the final design of the process was an iterative process, the NEB required Trans Mountain to continue to consult with potentially affected Aboriginal groups on issues such as routing, and mitigation measures.

<u>Pipeline and Facility Integrity</u>

Trans Mountain submitted that the construction of the Project involved the following pipe sizes and lengths:

- Approximately 339 km of 914 mm pipeline from Edmonton to Hinton, Alberta;
- Approximately 121 km of 1067 mm outside diameter pipeline from Hargreaves to Blue River, British Columbia;
- Approximately 158 km of 914 mm pipeline from Blue River to Darfield, British Columbia; and
- Approximately 368 km of 914 mm pipeline from Black Pines to the Burnaby Terminal, British Columbia.

Trans Mountain stated that its tanks at the current storage facilities on the Trans Mountain system had a combined capacity of 1,718,690 cubic meters in 57 tanks. Trans Mountain estimated an additional 20 tanks with a combined capacity of approximately 876,040 cubic meters, that would be constructed within the existing terminal property.

Trans Mountain submitted that the pipeline would all be designed, constructed, operated, maintained and abandoned in accordance with the *Onshore Pipeline Regulations* and with CSA Z662-15 standards. Trans Mountain also committed to complying with the requirements of various industry codes, standards, specifications, and recommended practices, and committed to implement failure prevention and spill mitigation measures in its design to achieve risk levels that are as low as reasonably practicable ("ALARP").

Trans Mountain estimated that, based on a design flow rate of 90,370 cubic meters per day, that it would require 11 pump stations to operate the pipeline at an acceptable availability factor, assuming planned shutdowns for maintenance, and other operational flexibility parameters.

Trans Mountain proposed to install 55 check valves, 72 remote mainline block valves (71 of which would be automated) and 12 mainline block valves and 11 associated check valves located at new pump stations. Specific locations of each valve would be subject to the iterative detailed design and engineering process, in order to best protect the environment. Trans Mountain proposed to use remote mainline block valves with check valves on the downstream side of major watercourse crossings, and not automatic shut-off valves.

Trans Mountain proposed to implement watercourse crossing methods using either open-cut, trenchless or isolated methods. Trans Mountain submitted that its decision to use each method would vary depending on site-specific hazards and environmental considerations. Trans Mountain submitted that it had identified 23 major watercourse crossings as being favourable for isolated crossings using HDD.

Trans Mountain submitted that it planned to provide point-specific maximum operating pressures for the Project, which are expected to vary between 6,000 and 10,000 kPa.

Trans Mountain noted that it considered a theoretical future expansion scenario of 124,010 cubic meters per day, which would require installing new pipeline segments, and additional pumping units.

The NEB determined that the proposed design approach and standards comply with the current regulations. The NEB held that Trans Mountain followed accepted engineering practices during the conceptual and preliminary design phases. With respect to minimum wall thicknesses however, the NEB imposed a condition on Trans Mountain to undertake a risk assessment to identify the locations where heavier walled pipe was required.

While the NEB noted Trans Mountain's commitment to ensure that risk was managed to levels that were ALARP, it found that Trans Mountain had not provided sufficient information regarding risk scores taking into account failure prevention and spill mitigation measures. Accordingly, the NEB imposed a condition on Trans Mountain requiring it to file an updated risk assessment for the Project with the NEB.

The NEB imposed a condition on Trans Mountain requiring it to reassess the feasibility of HDD crossings on major watercourses based on the outcomes of its detailed engineering and design, and file the feasibility and design reports with the NEB.

<u>Construction and Operations</u>

Trans Mountain submitted that it would develop a Health and Safety Management Plan ("HSMP") during the detailed engineering and design phase to reduce risk, and protect the health and safety of workers and the public during construction. Trans Mountain submitted that it would be the prime contractor for pump stations, terminals and other facilities, however, external contractors would be brought in to:

- Conduct risk assessments for construction of the assigned Project component;
- Developing and implementing Project Specific Safety Plans ("PSSP") to align with the HSMP; and
- Submit the PSSP to Trans Mountain for approval at least 60 days prior to commencing construction.

Trans Mountain also committed to developing a Traffic and Access Control Management Plan ("TACMP") where plans may directly affect public safety during construction. In addition, Trans Mountain committed to develop and implement blasting management plans, fire prevention and fire contingency plans, and a noise control plan.

Trans Mountain stated that controls to ensure public safety during construction would be determined through its detailed construction planning and consultation efforts with municipal authorities and stakeholders. Any additional controls would be integrated into the HSMP and PSSPs. Trans Mountain further committed to a communications program to ensure local businesses and the public were made aware of any potential construction impacts, including general safety requirements, lane restrictions, road closures and alternate access plans.

Trans Mountain noted that access for emergency services would be a critical component in its TACMPs and local traffic control plans, to ensure that emergency response providers are made aware of any potential traffic impacts or disruptions caused by the Project.

The NEB held that it would impose a condition requiring a submission of the manuals and plans proposed by Trans Mountain to the NEB in advance of construction. The NEB also determined that it would require more information following detailed design work to ensure that work conducted along the Project can be completed safely, and accordingly imposed a condition requiring the submission of, among other items, confined space entry procedures.

With respect to emergency preparedness, Trans Mountain committed to develop and implement a construction Emergency Response Plan ("ERP") separate from Trans Mountain's ERP for operations. Trans Mountain submitted that its construction ERP would be designed to ensure timely and appropriate emergency response in compliance with all applicable regulatory and legislative requirements, and would guide the development of site-specific ERPs. Each site-specific ERP would address injury and health incidents, environmental damage, fires, floods, earthquakes, rock slides, avalanches, sabotage, trespass and other emergency situations that could occur during construction.

The NEB held that it would impose a condition on Trans Mountain requiring the submission of its construction ERPs in advance of construction to ensure that regulatory requirements are met and that potential emergencies during construction are addressed.

Trans Mountain submitted that, if approved, the Project would be integrated with Trans Mountain's existing programs and management systems. With respect to the safety and security management aspects of the programs, Trans Mountain submitted that it would operate the Project in accordance with its current Integrated Safety and Loss Management System ("ISLMS"). Trans Mountain submitted that the ISLMS ensured that risks to its employees, contractors, the public and the environment were minimized.

The B.C. Wildlife Federation commented that security programs and systems should extend to any parts of the Project with unburied or exposed pipe, including expansion joints or pigging stations, as these facilities may be targets for vandalism.

Some participants expressed concerns regarding a lack of trust in Trans Mountain and its affiliates' safety record in particular. However, the NEB noted that a number of comments collected by Simon Fraser Student Society and The Graduate Student Society at Simon Fraser noted an overall opposition to the pipeline. The data provided indicated that the infrequency of serious incidents, the need for oil and the relative safety of pipeline transport compared to rail were themes that the Simon Fraser Student Society noted were supportive of the proposed Project.

Trans Mountain responded that security programs and systems would extend to all parts of the Project during construction and operations, including unburied segments.

In its findings, the NEB imposed a condition requiring Trans Mountain to confirm, prior to commencing operations, that it update its operations security management program to incorporate the Project. Due to the sensitive nature of such plans, Trans Mountain was not required to file a copy with the NEB. However, the NEB noted that the security management programs would be subject to assessment and ongoing NEB lifecycle compliance verification.

Trans Mountain submitted that it would provide a qualified and experienced team to inspect all phases of construction activities to ensure:

- Compliance with procedures, specifications and drawings;
- Compliance with legislative requirements, permit conditions and other undertakings; and
- Conformance with Project health, safety, security and environmental plans and procedures.

Some commenters expressed concerns with how the NEB would enforce Project conditions, noting a general perception that conditions imposed were essentially self-reporting checklists for Trans Mountain, with little oversight from the NEB. Many commenters, in respect of the draft conditions released by the NEB, submitted that the phrase "unless the NEB otherwise directs" in many of the conditions, would give the NEB excessive power to alter conditions, or release Trans Mountain from compliance altogether.

The NEB, in providing its findings, imposed five overarching conditions, the effect of which, the NEB held would make all commitments, plans and programs referenced or agreed to on the record of the proceeding, regulatory requirements of the NEB. The NEB further directed Trans Mountain to file commitments tracking tables, phased filing information, a list of temporary infrastructure sites, construction schedules, construction progress reports, and a signed confirmation of Project completion and compliance. The NEB also explained that the phrase "unless the NEB otherwise directs" is to provide the NEB with flexibility to vary conditions in a timely manner, without requiring Governor in Council approval for minor items. However, the NEB stated that for larger amendments or changes to the Project, Trans Mountain would be required to submit an application to the NEB pursuant to section 21 of the *NEB Act*.

Environmental Behaviour of Spilled Oil

Trans Mountain submitted that oil spills on land tend to move downslope, sink downward under gravity, and spread horizontally and in the subsurface. Trans Mountain noted that oil continues to lose mass once spilled, either through dissolution, evaporation or biodegradation. Trans Mountain submitted that the process of depletion slows over time, as remaining complex hydrocarbons are more prone to resist weathering and depletion.

Trans Mountain submitted that the weathering process in an aquatic environment was substantially the same in freshwater and marine environments. Spills can generally be expected to initially float on the surface, except where the water is turbulent enough to entrain the spilled oil, or create an emulsion.

Trans Mountain submitted that during the weathering process, spilled oils may sink after lighter hydrocarbons evaporate or dissolve, and the remaining oil mixture is denser than water. However, Trans Mountain explained that different factors can affect the speed of such changes, including temperature, wind speeds, wave heights, salinity, sedimentary concentrations, and oil composition.

Trans Mountain stated that its tariff on the Project would limit the maximum density of oil at 940 kilograms per cubic meter and a maximum viscosity of 350 centistokes. Trans Mountain expected that, in the event of a spill, the diluted bitumen transported on the Project would likely behave in a manner similar to Bunker C fuel oil, which typically floats on the water with a slightly lower density than water, and may form viscous emulsions within 24 hours of a spill.

Trans Mountain modelled a worst case spill volume of approximately 1,250 to 2,700 cubic meters at several locations on the Project. Trans Mountain submitted that its model indicated that the majority of the oil spilled was expected to strand along the shorelines, as the suspended sediment concentrations (in the Fraser River) were seen as much lower, and therefore not as prone to sinking as other waterways. Trans Mountain stated that the expected length of affected shoreline ranged from 25 kilometers in summer, to up to 36 kilometers in winter, with approximately 74 percent being trapped on shore.

Several Aboriginal groups, the City of Vancouver and the City of Burnaby took issue with Trans Mountain's modelling results, submitting that the oil's physical and chemical properties were not assessed, and weathering was not taken into account in the modelling assumptions. Each also took issue with the modelled spill sizes, submitting that spill volumes ranging from 8,000 to 16,000 cubic meters in the Burrard Inlet was much more realistic for a spill near the WMT.

The NEB held that the literature was clear that although oil could typically submerge, it would not typically sink in large quantities nor float as a cohesive mat. However, the NEB determined that sinking of spilled oil would likely be limited in quantity, and only after significant weathering had occurred. The NEB noted that the potential for oil submergence would need to be considered by Trans Mountain in its emergency response planning.

The NEB also accepted that a majority of oil spilled on waterways would likely strand on the shorelines, which would necessitate challenging clean-up activities, due to the viscous and persistent nature of weather-diluted bitumen.

<u>Emergency Prevention</u>

Trans Mountain submitted that its primary goal was the prevention of spill, and it would employ management system and resources to ensure that this goal is achieved by the Project.

Trans Mountain noted that spill prevention and mitigation was embedded throughout the full Project lifecycle, and started with the risk assessment and engineering designs. Trans Mountain stated that its pipeline integrity management program would help ensure long-term spill prevention, and that its 60 year operating history demonstrates the low probability of a large pipeline spill. Notably, Trans Mountain proposed to integrate the Project into its existing emergency response and prevention strategies and plans, which would be enhanced further during detailed design and engineering.

Trans Mountain noted that from 1961 to 2013, it had reported 81 spills to the NEB, including a number that were under the reportable limits and did not cause any environmental damage. Trans Mountain also noted that no reportable spill events have occurred on its Anchor Loop facilities that go through Jasper National Park and Mount Robson Provincial Park.

Trans Mountain noted that after third party damage to its pipeline occurred due to a contractor for the City of Burnaby, it implemented a Pipeline Protection Department. Pipelines are protected through markings, issuance of safe work permits and responses to British Columbia and Alberta One Call requests.

A number of interveners requested further clarification on how human error would factor into Trans Mountain's spill response times in Trans Mountain's modelled scenarios. Trans Mountain noted that human error is a key consideration in the development of procedures that must be followed at its control centre, and such considerations are built into its training programs. Trans Mountain also noted that human error can be mitigated through enhanced communication built into control centre procedures.

At the WMT, Trans Mountain submitted that it would deploy at all times a containment boom around any ships at the WMT, so that in a worst case scenario, only 20 percent of oil would escape (or approximately 32 cubic metres according to Trans Mountain's modelling). Trans Mountain also submitted that it will enact wind speed limits for safe loading of tankers at the WMT in the detailed design phase.

Trans Mountain submitted that it would use inert gas on its crude oil tankers to virtually eliminate the risk of cargo-related fire and explosions.

As part of its Emergency Management Plan ("EMP"), Trans Mountain would produce the following plans and supporting documents for the pipelines, terminals and tank farms:

- the Incident Command System (ICS) Guide;
- Emergency Response Plans (ERPs): Westridge Marine Terminal ERP, Trans Mountain Pipeline ERP, Terminal and Tank Farms ERP;
- Control Point Manual;
- Tactical Response Plans (e.g., submerged and sunken oil);
- Geographic Response Plans;
- Trans Mountain Field Guide;
- Fire Safety Plans; and
- Fire Pre-Plans.

Trans Mountain noted that in the event of a spill, it would take the following immediate steps in response:

- Immediate shutdown of pipeline or other source of release and allow pressure to dissipate to prevent additional release of hydrocarbon and isolate the source of the spill from the rest of the system;
- Immediately contact local emergency services and trained Trans Mountain technicians for dispatch to the location, to help secure the area and commence air monitoring to ensure air quality for those in the immediate vicinity;
- Control centre issues an Emergency Response Line (ERL) notification to the Incident Management Team (IMT). Upon notification the IMT calls the conferencing line to get information about the incident and begin pre-assigned response duties;
- Immediately following the ERL conference call, Trans Mountain notifies the Transportation Safety Board of Canada (TSB) and NEB;
- Liaison Officer begins notifications to other groups not included in the above notifications;
- Logistics Section Chief begins identification of resources required for the response and ordering supplies and equipment; and
- Planning Section Chief begins planning recovery operations and contacting team members required including the Environmental Unit Leader.

With respect to specific spill response techniques, Trans Mountain submitted that it would respond to the unique requirements of any spill at its facilities, and provided the following examples of response strategies:

- capturing the oil where currents and hydrographic conditions are amenable to the deployment of oleophilic material to trap the oil;
- remobilization, containment, and removal of the oil through agitation of sediments (raking, dragging, pneumatic agitation);
- bulk removal of the oil through pumping and/or dredging; or
- long-term monitoring and natural attenuation in areas where remedial actions pose more harm than benefit.

Trans Mountain stated that mobilization of crews for emergency response would begin immediately, and has pre-designated incident command posts and staging areas at locations along the current pipeline corridor and in communities where its facilities are located. Trans Mountain also noted that for preparation, it would work with external emergency response service, such as through annual training with external agencies.

Trans Mountain committed to enhance its year-round emergency response capacity by developing geographic response plans ("GRP") to account for the varying terrain across the pipeline corridor. Trans Mountain submitted that its GRP would include:

- A review of both Lines 1 and 2 with production of a response capability analysis, which will serve as a key foundational element for the new GRPs that would be developed;
- Development of a complete set of GRPs covering both Lines 1 and 2. These GRPs will provide responders with guidance and detailed information on access, deployment and product ;
- Recovery as well as strategies and tactics relevant to environmental conditions throughout the year;
- Guidance for KMC responders for other environmental factors such as full or partial ice cover of rivers, streams and lakes, forest fire and smoke, avalanche and flooding conditions;
- A full review of control points including spacing, access suitability under various environmental conditions and others;
- Consultation with First Nations, local and regional governments, as well as Trans Mountain's existing mutual aid partners; and
- Shoreline Cleanup and Assessment Technique (SCAT) guidance.

Many municipalities expressed concern over the ability of their own first responders, such as the RCMP, to mitigate a major fire event, such as a tank fire, storage tank boil over, or release of toxic gases. The City of Port Moody and the City of Kamloops stated that Trans Mountain provided scant information regarding the resources that would be directed to their municipalities in the event of a spill or accident, and felt ill equipped about how to respond to a spill or accident. Each of the municipalities and the Province of British Columbia requested a full disclosure of Trans Mountain's EMP to afford them an opportunity to evaluate its adequacy.

Trans Mountain replied by committing to enhancing its fire detection, mitigation and prevention measures at its Burnaby Terminal. Trans Mountain will include industry leading fire protection equipment, and full-surface fire-fighting foam suppressions systems. Trans Mountain estimated that industrial firefighting contractors would be capable of responding to an incident within 6 to 12 hours.

Trans Mountain also noted that, when working with municipalities after an incident, it prefers to enter into a unified command with municipal, provincial and federal authorities to ensure a thorough response to the incident, and prioritize objectives without redundancy.

The NEB held that while all possible environmental conditions cannot be known or replicated, it nonetheless expects companies to be prepared for spills of all sizes and in all conditions.

The NEB held that it was satisfied with Trans Mountain's commitment to review and revise its EMP to address the needs of expanding its system due to the Project. The NEB was satisfied with Trans Mountain's commitment to consult with first responders and communities with respect to changes to the EMP. The NEB also imposed conditions reflecting its findings on Trans Mountain's EMP.

The NEB found that the broad range of spill prevention and mitigation measures committed to by Trans Mountain, including deploying booms around tankers, were comprehensive and appropriate. However, the NEB determined that the 6 to 12 hour response time for firefighting crews was inadequate. The NEB therefore imposed a condition requiring Trans Mountain to complete a needs assessment to develop appropriate firefighting capacity in response to a fire at the WMT and at the Edmonton, Sumas and Burnaby Terminals on the Trans Mountain pipeline system.

The NEB reiterated that no spill is acceptable at any NEB regulated facilities. In the event of a spill, the NEB determined that incorporating the project into Trans Mountain's existing emergency management programs at its existing facilities would help Trans Mountain respond to and manage an incident on the Project more effectively.

<u>Environmental Assessment</u>

The NEB noted that the Project met the requirements of the *Regulations Designating Physical Activities* under the *Canadian Environmental Assessment Act, 2012* ("CEAA 2012"), and as a result, the NEB was required to conduct an environmental assessment ("EA") for the Project.

The NEB summarized the scope of the EA as comprised of the following three elements:

- The physical works and activities making up the Project (as described by Trans Mountain in its application and subsequent filings).
- The biophysical and socio-economic elements that are likely to be affected by the Project.
- The factors that must be taken into account in conducting an environmental assessment (described in section 19 of the CEAA 2012).

The NEB also determined that upstream and downstream activities (with the exception of Project-related shipping activities) would not form part of the EA, given that the Project did not include any upstream or downstream developments, nor did it depend on any particular project for a feedstock, and was therefore not necessarily incidental to Project approval.

The NEB noted that it examined the potential environmental impacts of the Project on marine fish, fish habitat, species listed under the *Species At Risk Act* and their respective habitat, plant life, the mitigation measures proposed by Trans Mountain, as well as the possibility of accidents and malfunctions.

The NEB noted that it used a spatial and temporal boundary for each valued component in the Project area. Where it found any effects that were predicted to remain after mitigation measures proposed by Trans Mountain, the NEB assessed the cumulative effects of all physical activities and facilities in the area, in addition to the Project itself.

Trans Mountain submitted that the NEB should examine the Project's contribution to cumulative effects, rather than the total cumulative effects for the purposes of the EA.

The NEB rejected Trans Mountain's position, holding that the CEAA 2012 requires examining the cumulative environmental effects that are likely to result from the Project, in combination with other physical activities that have been or will be carried out.

With respect to air quality and emissions, Trans Mountain submitted that overall air quality was very good with few exceedances of the relevant ambient air quality objectives, and that all predicted project related concentrations of emissions and particles would meet existing guidelines, except where existing exceedances are already occurring, such as at the Edmonton Terminal and WMT.

Trans Mountain also provided a summary of anticipated Project related emissions in the following table:

(CO2)	**Construction**	**Operating**	**Provincial**	**Change to Provincial total**
Alberta	177,000	407,000	249 million	0.164
B.C	844,000	(323)	60.1 million	-0.001
Total	1,020,000	407,000	699 million (Canada)	0.058

Many interveners took issue with Trans Mountain's air assessment modelling, submitting that Trans Mountain excluded relevant processes, or assumed near perfect operation of equipment, such as volatile organic compound collection equipment.

In noting the potential difficulties in verifying and validating air quality modelling, the NEB directed Trans Mountain to develop and implement air emissions management plans to protect the environment and human health, and to consult with stakeholders in developing the same. The NEB also required Trans Mountain to develop baseline data for emissions monitoring at the Edmonton, Sumas, WMT and Burnaby terminals.

The NEB determined that the air emissions from construction activities were likely to be intermittent, localized, reversible and of limited duration, and was therefore not likely to cause significant adverse effects. However, the NEB still imposed a condition requiring Trans Mountain to develop an offset plan for the Project's entire direct construction-related greenhouse gas emissions that are determined post-construction, to ensure no net emissions from construction. The NEB determined that the emissions anticipated during operations would be below national reporting thresholds, and accordingly were not considered significant.

With respect to watercourse impacts and crossing methods, Trans Mountain proposed to implement a number of mitigation measures to address potential impacts, including:

- hydraulic isolation will be implemented for any small to medium sized streams that are hydraulically connected to fish habitat;
- fish salvages at each isolated trenched crossing and at all fish-bearing crossings;
- water quality monitoring for suspended sediment during trenchless and isolated trenched;
- crossings of watercourses with high sensitivity fish habitat;
- working within the least-risk biological windows; and
- completing spawning surveys before and during construction.

The NEB held that finalized, site-specific information was needed to make an accurate serious harm determination, despite the mitigation measures proposed. Accordingly, the NEB directed Trans Mountain to file site-specific information for each proposed crossing as well as impacts on fish and fish habitat, prior to construction. The NEB also directed Trans Mountain to file any authorizations obtained from the Department of Fisheries and Oceans with the NEB prior to construction.

The NEB also imposed general conditions on crossing methods for watercourses, directing Trans Mountain to employ trenchless water crossing methods (such as HDD) if working in the critical habitat of Nooksack dace and Salish sucker fish.

With respect to impacts on plants and vegetation, Trans Mountain noted that long term loss of native vegetation would occur in the long term on its facilities, comprising approximately 2,231 hectares of native vegetation. Trans Mountain noted that disturbed areas would revegetate after construction, albeit in an altered state due to right of way maintenance obligations. Trans Mountain proposed the following mitigation measures for rare plants and lichens:

- complete avoidance would be adopted for rare plants, lichens, and communities ranked imperiled or critically imperiled, and for species or critical habitat that are protected under provincial or federal legislation, subject to factors such as construction and workers' safety;
- disturbance reduction could include measures such as placement of protective structures over plants of concern, and restricting use of herbicide near vegetation communities or sub-populations; and
- where avoidance and disturbance reduction are not feasible, alternative reclamation techniques would be used, such as propagating and transplanting to suitable receiving sites, and

stripping the upper 15 cm of topsoil separately where feasible to make use of the existing seed bank.

Trans Mountain also proposed to establish baseline data for rare plants, and monitor data on and off the right of way.

The NEB held that Trans Mountain must file environmental protection plans, reclamation management plans, access management plans, and rare plant species discovery contingency plans prior to construction.

The NEB determined that offsets for rare plant impacts are not always successful, and stressed the importance of avoidance and mitigation to reduce any adverse effects. In making this finding, the NEB held that Trans Mountain's proposed avoidance and mitigation measures were expected to avoid adverse effects, and therefore did not require offsets.

Trans Mountain summarized the following potential Project effects on wildlife, including migratory birds, and their habitat:

- change in habitat from vegetation clearing and sensory disturbance;
- change in movement from reduced habitat connectivity and creation of barriers or filters to movement; and
- increased mortality risk resulting from collisions with vehicles or equipment, loss or disruption of habitat features, or sensory disturbance.

Trans Mountain noted that linear disturbances from right of way clearings would result in increased predator efficiency, and improved access for trapping, hunting and poaching of wildlife, leading to potential increases in wildlife mortality.

In order to mitigate these potential effects, Trans Mountain noted that it sited the majority of the Project along existing disturbances to minimize new clearing areas, and avoid areas designated as critical habitat for caribou and grizzly bear populations where feasible.

Trans Mountain further committed to conduct post-construction environmental monitoring for five years to determine the effectiveness of its mitigation and avoidance measures.

The NEB held that destruction of critical habitat for caribou and grizzly bear populations be avoided. Where avoidance is not possible, the NEB directed Trans Mountain to develop and implement a caribou habitat restoration plan to offset any lost habitat from construction and operation of the Project such that there is no net loss of habitat.

The NEB determined that with the above mitigation and offsets, the potential for the Project to adversely impact predator-prey dynamics in the Project area was low.

With respect to marine impacts, Trans Mountain noted that based on information available, the waters surrounding the proposed WMT indicate elevated levels of polycyclic aromatic hydrocarbons, cadmium and mercury, and chronic oil contamination from existing developments. Trans Mountain noted that among the impacts from construction, it would dredge approximately 150,000 cubic meters of intertidal and nearshore subtidal materials. Trans Mountain committed to reducing the total amount of dredging required, and further proposed the following mitigation measures:

- minimize or completely avoid the dredging footprint required for the WMT;
- employing clamshell dredging and silt curtains to limit any potential sediment release during dredging;
- monitor turbidity and suspended solids in the water during construction; and
- follow erosion and sediment control measures on land to limit sediment release in water.

Trans Mountain also estimated the following impacts on marine fish habitat due to the construction of the WMT and tanker berths:

Habitat	**Area to be lost (m2)**
Marine riparian habitat	2,252
Intertidal habitat	4,323
Subtidal habitat	13,002
Total	**19,577**

Trans Mountain noted that some marine organisms may be killed during construction due to pile driving, dredging or infilling, although Trans Mountain noted a low abundance of potentially impacted species in the area surrounding the WMT.

The NEB acknowledged the existing water contamination around the WMT, and imposed a condition requiring Trans Mountain to develop and implement a marine sediment management plan, along with monitoring during construction.

The NEB also imposed a follow-up monitoring program on Trans Mountain to assess the effectiveness of Trans Mountain's proposed mitigation measures, and file these results with the NEB.

The NEB found that Trans Mountain's ecological risk assessments for the Project were appropriate.

Need for the Project

The NEB noted that it must consider the need for and economic feasibility of the Project under section 52 of the *NEB Act*, having regard to:

- The availability of oil, gas or other commodities to the Project;
- The Existence of markets, actual or potential; and
- The economic feasibility of the Project.

Accordingly, the NEB noted that it requires applicants to provide the following economic information:

- Supply – evidence that there is or will be adequate supply to support the use of the pipeline;
- Transportation – Evidence indicating that the volumes are appropriate for the applied-for facilities, and that they will be utilized at a reasonable level over their economic life;
- Markets – Evidence indicating that adequate markets exist for the increased volumes available to the marketplace; and
- Financing – Evidence of the applicant's ability to finance the facilities, including method of financing, and any changes to the financial risk of the company as well as toll impacts and abandonment cost estimates.

Trans Mountain submitted that the Project was required from a broader public interest perspective, to ensure that the highest value is obtained for produced petroleum resources. Trans Mountain submitted that sufficient pipeline capacity is needed for Western Canadian producers to access the highest value markets, and would support one of the NEB's stated goals to have Canadians benefit from efficient energy infrastructure.

A consortium of shippers, consisting of Canadian Oil Sands, Devon, Cenovus, Husky Oil, Imperial Oil, Statoil, Suncor, Tesoro and Total (the "TMX Shippers") submitted that the Project was in the best interest of Canadians to diversity the markets for its oil exports by providing enhanced access to tide water. The Project was similarly supported by the Explorers and Producers Association of Canada.

Trans Mountain submitted that current demand for transportation services on the existing Trans Mountain pipeline exceeds capacity, and results in a need to apportion available capacity. The resulting apportionment of capacity was, in Trans Mountain's submission, a clear indicator of the value placed by shippers on obtaining access to the west coast and offshore markets.

Trans Mountain submitted that the Project was underpinned by firm commitments of 112,300 cubic meters per day (or 707,500 bpd), representing 80 percent of the nominal capacity on the expanded system. Trans Mountain noted that 13 shippers have signed 15 or 20 year commitments, and demonstrate that the Project can be expected to be utilized at a high rate. Trans Mountain also noted that its shippers are significant players in the petroleum industry and have investment grade or better credit ratings, which would provide assurance for Trans Mountain to meet its long-term financing requirements.

Trans Mountain also submitted that higher prices for Western Canadian Crude would provide total producer benefits of approximately $73.5 billion on an undiscounted basis, and a present value of approximately $38 billion attributable to the market access provided by the Project from 2017-2037. Trans Mountain further estimated the direct federal and provincial benefits to be approximately $23.7 billion over the life of the Project, excluding incremental benefits from refining, processing and downstream activities.

Living Oceans submitted that the contractual capacity does not confirm the need for the Project, given that the contracts were negotiated in 2011 and 2013, and noting that circumstances have changed materially since that time.

Trans Mountain submitted evidence that global benchmark prices for oil are usually identical after accounting for quality and transportation costs, however, this was not the case in recent years for North American markets, with prices lagging considerably. Trans Mountain's evidence pointed out that the pricing imbalance was primarily due to lack of market diversification for Canadian Crude.

Trans Mountain's evidence did not address or assume any impacts on the Canadian economy from higher crude oil prices, or any impacts on the refining sector. Trans Mountain also did not factor in Energy East, Keystone XL or Northern Gateway pipelines in its price forecast scenarios, given uncertainty with the tolling and timing information available.

Trans Mountain submitted that Western Canadian crude oil supply is forecast to grow from 635,000 cubic meters per day in 2015 to 1.01 million cubic meters per day in 2038. While Trans Mountain noted that many forecasts differ somewhat in later years, they broadly communicate a significant increase in crude oil supply in the future.

Trans Mountain provided evidence that it did not anticipate the Project acting as a price setting mechanism because it would not transport the marginal or incremental barrel of Western Canadian crude oil.

Trans Mountain submitted that the markets accessed would be in the Burnaby and Puget Sound area, and Northeast Asia, with secondary markets in California and Hawaii. Trans Mountain submitted that refineries in Puget Sound have a combined capacity of 100,410 cubic meters per day, while potential demand from Northeast Asia exceeds 369,700 cubic meters per day. For secondary markets, Trans Mountain submitted that economics of selling to California is made difficult because of high CO2 emissions ratings, as well as the cost of upgrading and refining heavy crude.

With respect to Project financing, Trans Mountain submitted that the total capital cost of the Project would be approximately $5.5 billion, including construction costs of approximately $3.6 billion.

The City of Burnaby submitted that Trans Mountain's application and evidence provided a distorted and unrealistic picture of the economic impact and economic feasibility of the Project. The City of Burnaby submitted that Trans Mountain misinformed the NEB, obfuscated issues, and withheld pertinent financial and economic information from the record. The City of Burnaby submitted that Kinder Morgan (Trans Mountain's parent company) was downgraded by three credit ratings agencies in 2014, and was delisted from the New York Stock Exchange, but did not update its application to reflect these developments. Kinder Morgan was recently unsuccessful in gaining an enhanced credit rating above BBB- from Standard and Poor's, Baa3 from Moody's and BBB- from Fitch, all of whom identified Kinder Morgan's vulnerability to a credit downgrade.

Other interveners challenged Trans Mountain's evidence, stating that Trans Mountain underestimated the amount of capacity that will be in place, and would result in excess capacity. Interveners also submitted that the Project was not needed and that investment was better suited towards building non-polluting energy projects.

The Government of Alberta submitted that improved market access for Canada's oil and gas industry would substantially increase corporate income taxes, and would further increase employment opportunities across Canada. The Project was supported on similar grounds by the British Columbia Chambers of Commerce and the Edmonton Chambers of Commerce.

The City of Vancouver criticized Trans Mountain's supply evidence, submitting that the forecasts provided did not account for infrastructure constraints, and effectively assumed construction of other pipelines outside the Project.

The Canadian Association of Petroleum Producers submitted that forecasts show that the rate of supply growth did not change the fact that supply was growing and required increased market access.

British Columbians for Prosperity stated that due to the bottlenecked transportation system for crude oil, and declining demand from the United States, Canada receives a discounted price for its oil. In their submission, the Project would help to rectify the current price discount for Western Canadian crude oil.

The NEB held that increasing pipeline capacity for the purpose of accessing Pacific Basin markets was important to the Canadian economy, which it held was a significant benefit of the Project. The NEB accepted that committed shippers for the Project were seeking growth market alternatives for production, and found that the Project would provide access to these markets.

The NEB held that the forecast supply and market demand growth, combing with robust contractual and financial underpinnings for the Project, demonstrated that the Project would be used and useful over its economic life, and that Trans Mountain would be able to finance the Project.

<u>Financial Matters</u>

The NEB noted that section 52(2)(d) of the *NEB Act* required the NEB to consider the financial assurances directly related to facilities and activities regulated by the NEB, including financial responsibility and financial structure of Trans Mountain.

Trans Mountain submitted that it was an Alberta unlimited liability corporation, and the general partner of Trans Mountain Pipeline L.P, holding 0.01 percent partnership interest. Trans Mountain submitted that it would hold the CPCN, should it be issued. The Project would be operated by Kinder Morgan Canada Inc.

Trans Mountain submitted that it has unlimited liability for the liabilities and obligations of Trans Mountain L.P. Kinder Morgan Cochin ULC, as the limited partner of Trans Mountain Pipeline L.P, would not be liable to creditors of Trans Mountain L.P. The liability of a limited partner is limited to any amount of its required capital contributions that are unpaid.

Trans Mountain also filed an expert report to assess the potential costs of oil spills ranging from 4.8 cubic metres, to a 4,000 cubic meter spill on the Project. Trans Mountain examined the costs of spills in high consequence areas ("HCA"), and outside of high consequence areas ("non-HCA"). Trans Mountain submitted the following estimated costs of remediating hypothetical crude oil spills from the Project:

Scenario	**Leak**	**Rupture**		**Terminal Loading**
Spill Size	30-715	12,580	25,160	648
Location	Non-HCA	HCA	HCA	HCA
Cleanup Cost/bbl	$34,000 to $11,076	$12,580	25,160	648
Damage cost/bbl	$51,122 to $16,615	$3,532	$3,532	$11,000
Total cost/bbl	$85,203 to $27,691	$5,298	$10,000	$9,350
Total cost of spill	**$2,556,090 to $19,799,065**	**$111M**	**$340M**	**$13M**

The NEB held that the limited partnership structure of Trans Mountain was acceptable, but that the NEB would impose Condition 121, which requires Trans Mountain to maintain $1.1 billion in financial assurances, since Trans Mountain is responsible for cleaning up the environment and compensating affected parties in the case of an oil spill.

Project-related Increase in Shipping Activities

The NEB found that increased marine shipping to and from the WMT was not part of the Project for the purposes of its inquiry. However, the NEB noted that it would consider the potential effects of shipping activities, and any accidents or malfunctions under the *NEB Act*. To the extent that there is potential for the effects of the increased marine shipping to interact with the environmental effects of the Project, the NEB noted that it considered such impacts as part of the cumulative effects portion of its environmental assessment.

Order and conditions

The NEB conditionally approved the Project, imposing 157 conditions on Trans Mountain. The NEB separated the conditions imposed on the Project in two functional categories: subject matter and pipeline life-cycle stage.

Pipeline Conditions[1]	**Pipeline Life-Cycle Stage**				
Subject Matter	General	Pre- Construction	Prior to Operation	During Operation	**Total**
Regulatory Oversight	3	4	4	2	**13**
Economics and Financial Responsibility	-	1	1	1	**3**
Emergency Preparedness and Response	-	2	11	3	**16**
Environment	1	30	9	15	**55**
People, Communities, and Lands	-	30	7	5	**42**
Safety	1	21	12	4	**38**
Shipping and Watercourses	-	52	32	12	**96**
Total	**5**	**140**	**76**	**42**	--

1 Note: Some conditions apply to multiple subjects or stages of life-cycle operations.