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REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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

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SUPREME COURT OF CANADA

***Ernst v Alberta Energy Regulator*, 2017 SCC 1**
Alberta Energy Regulator – Statutory Immunity for Administrative Decision Making Bodies – Availability of Charter Remedies Against Regulatory Bodies

In *Ernst v Alberta Energy Regulator*, the SCC considered an appeal of the Alberta Court of Appeal ("ABCA") decision *Ernst v. Encana Corp.*, 2014 ABCA 285 (the "ABCA Decision"). The ABCA Decision affirmed an Alberta Court of Queen's Bench ("ABQB") decision striking Jessica Ernst's claim against the Alberta Energy Regulator (the "AER") for an alleged breach of Ms. Ernst's right to freedom of expression under section 2(b) of the *Charter of Rights and Freedoms* (the "*Charter*").

Specifically, the SCC considered whether:

1. Ms. Ernst's pleadings made out a claim for a breach of her right to freedom of expression under *Charter* section 2(b); and
2. If so, whether the statutory immunity conferred on the AER under section 43 of the *Energy Resources Conservation Act (*"*ERCA*") barred Ms. Ernst's claim for damages under *Charter* section 24(1).

Section 2(b) of the Charter provides:

> 2. Everyone has the following fundamental freedoms:
>
> …
>
> (b) freedom of thought, belief, opinion and expression, including freedom of the press and other media of communication;

Section 24(1) of the *Charter* provides for broad remedies where a person's rights or freedoms have been infringed. Section 24(1) stated:

> 24. (1) Anyone whose rights or freedoms, as guaranteed by this Charter, have been infringed or denied may apply to a court of competent jurisdiction to obtain such remedy as the court considers appropriate and just in the circumstances.

ERCA section 43 provided the Energy Resources Conservation Board (the predecessor to the AER) with broad immunity. It states:

> 43 No action or proceeding may be brought against the Board or a member of the Board or a person referred to in section 10 or 17(1) in respect of any act or thing done purportedly in pursuance of this Act, or any Act that the Board administers, the regulations under any of those Acts or a decision, order or direction of the Board.

<u>ABQB and ABCA Decisions</u>

In the ABQB decision (2013 ABQB 537) (the "ABQB Decision"), the case management judge struck both Ms. Ernst's negligence and *Charter* claims against the AER as being barred by *ERCA* section 43.

On appeal, the ABCA affirmed the ABQB's decision striking Ms. Ernst's claim on the basis that her claim for *Charter* damages was barred by *ERCA* section 43. The ABCA did not consider whether Ms. Ernst's pleadings made out a claim for a breach of *Charter* section 2(b).

Ms. Ernst appealed the ABCA Decision to the SCC. Ms. Ernst submitted that *ERCA* section 43 is unconstitutional to the extent that it purports to bar a person's *Charter* claim against the AER and a remedy in damages under section 24 of the *Charter*.

Ms. Ernst did not appeal the part of the ABCA Decision striking Ms. Ernst's negligence claim on the basis that the AER owed no private duty of care to Ms. Ernst.

<u>SCC Affirming ABCA Decision</u>

The SCC rendered a 4-4-1 split decision. Five of the nine SCC justices agreed that the claim should be struck. The appeal was therefore denied.

However, only four of the nine justices (Cromwell J., with Karakatsanis J., Wagner J, and Gascon J. concurring) decided the question of the constitutionality of *ERCA* section 43, holding that Ms. Ernst failed to establish that the immunity provision was unconstitutional.

Justice Abela was the deciding vote dismissing the appeal. However, she would have dismissed the appeal on the grounds that Ernst failed to provide the required notice of a constitutional challenge. For this reason, there was not a majority determination as to the constitutionality of *ERCA* section 43.

The remaining four justices, in a dissenting opinion, would have allowed the appeal but declined to answer the constitutional question.

<u>Reasons of Justice Abela</u>

Justice Abela would have dismissed the appeal on the basis that Ms. Ernst failed to provide the required notice of a constitutional challenge under section 24 of Alberta's *Judicature Act*. Justice Abela also held that *ERCA* section 43, on its face, barred Ms. Ernst's claim. Therefore, in Justice Abela's opinion, Ms. Ernst's claim failed to disclose a reasonable cause of action.

Justice Abela held that it would not be appropriate to address the constitutionality of *ERCA* section 43 given Ms.

Ernst's failure to provide the required notice and expressly denying in the lower court proceedings that she was challenging the validity of the legislation itself.

Justice Abela noted that notice requirements are not just a procedural technicality. Rather, the notice requirement serves a "vital purpose" when constitutional questions arise in litigation. Notice ensures "that courts have a full evidentiary record before invalidating legislation and that governments are given the fullest opportunity to support the validity of legislation."

Reasons of Justice Cromwell (with Justices Karakatsanis, Wagner, and Gascon concurring)

Justice Cromwell held that *ERCA* section 43, on its face, barred Ms. Ernst's Charter claim. This left only the question of whether Ms. Ernst had successfully challenged the constitutionality of section 43. Justice Cromwell held that she had not.

Justice Cromwell noted that there was no dispute between the parties that *ERCA* section 43, on its face, purports to bar Ms. Ernst's claim for *Charter* damages. He noted that Chief Justice McLachlin et al would have allowed the appeal on the basis that it was not plain and obvious that the immunity provision barred Ernst's claim. Justice Cromwell found the dissenting justices' reasoning problematic for a number reasons, including:

1. the fact that Ernst argued in her submissions the contrary position – that *ERCA* section 43, on its face, did bar her claim;

2. that although the Court is not bound by parties' positions on questions of law, no party cited authority to suggest Ms. Ernst's position was wrong in law – nor was Cromwell aware of any; and

3. that it would therefore be unfair to the AER to find otherwise, as the AER had no reason to expect that this issue was in question, let alone that the appeal might turn on it.

Justice Cromwell held that Ernst had failed to establish that section 43 is unconstitutional on the grounds that she had not provided an adequate factual basis on which the court could decide the challenge. Cromwell held that, contrary to the result reached by the four dissenting justices, a court cannot refuse to rule on the immunity clause's constitutionality, yet also refuse to apply it. Because there is a presumption of constitutionality, Justice Cromwell held that the immunity clause must be applied and therefore the appeal should be dismissed.

Justice Cromwell further held the *Charter* damages could never be an appropriate remedy for *Charter* breaches by the AER.

Justice Cromwell noted that *Charter* damages may provide compensation and deter future violations. However, in the case of a regulatory board such as the AER, awarding monetary damages to an individual may inhibit effective government. There are other remedies available for a claimant to seek redress for a *Charter* breach, without having such a broad adverse impact on the public interest and ability of regulators to fulfill their respective mandates. In this case, Justice Cromwell held that judicial review was an alternative effective remedy for any AER breach of a claimant's *Charter* rights.

Justice Cromwell, citing the SCC decision *Ward v. Vancouver (City)*, 2010 SCC 27, held that damages under section 24(1) of the *Charter* would not be an appropriate remedy because in this case there was an effective alternative remedy. Awarding damages for a claim against the AER would be contrary to the demands of good governance.

Reasons of McLachlin C.J. and Moldaver and Brown (Cote J. concurring)

Justices McLachlin et al. explained that, to determine whether a claim for Charter damages should be struck out on the basis of a statutory immunity clause, a court must:

1. first determine whether it is plain and obvious that *Charter* damages could not be an appropriate and just remedy; and

2. if it is not plain and obvious that *Charter* damages could not be appropriate and just, then the court must determine whether it is plain and obvious that the immunity clause, on its face, applies to the plaintiff's claim for Charter damages.

If it is plain and obvious that the immunity clause applies, a plaintiff must successfully challenge the clause's constitutionality. Otherwise, a court must give effect to the immunity clause and strike the claim.

Chief Justice McLachlin held that it was not plain and obvious that *Charter* damages could not be an appropriate and just remedy. McLachlin found that Ms. Ernst's pleadings raised two possible infringements on her section 2(b) rights, namely:

1. by the AER directing Ms. Ernst to stop expressing herself to the media and the public or else it would not consider her complaints; and

2. by the AER prohibiting Ms. Ernst from participating in the AER public complaints and enforcement process.

The Chief Justice characterized the first as an allegation that the AER acted with the purpose of limiting Ms. Enrst's expressive activity in the public sphere. The second she characterized as the AER's action having the effect of limiting Ms. Ernst's expression. Specifically, the AER's prohibition limited Ernst's freedom of expression in the context of her participation in social and political decision making relating to oil and gas development in Alberta.

With reference to the first part of the *Ward* test (alternative remedy) discussed above, McLachlin et al. stated:

> At the very least, it would be premature to conclude, based on the pleadings alone, that judicial review would provide an effective alternative remedy to *Charter* damages in this case, let alone in all cases, against the Board. We note that, under the Alberta Rules of Court, damages are not available through judicial review.

Chief Justice McLachlin et al. went on to consider the second part of the Ward test, namely, whether awarding *Charter* damages would be contrary to the demands of good governance. The dissenting justices noted that while the common law recognizes absolute immunity for judges in the exercise of their adjudicative function, the AER was not acting in such a capacity when it informed Ernst that she could not longer write to the Board until she ceased her public criticisms.

McLachlin et al. concluded that it was not plain and obvious that *Charter* damages could not be a just and reasonable remedy in the circumstances.

McLachlin et al. went on to consider whether it was plain and obvious that *ERCA* section 43, on its face, applied to bar Ms. Ernst's claim. McLachlin noted that the Court is not bound by the positions of the parties on questions of law. She went on to find that the circumstances of this case were exceptional and, in her view, compelled the Court to consider an issue not raised by the parties.

McLachlin et al. explained that Ms. Ernst raised a novel and difficult legal problem involving the interplay between legislative immunity clauses and s. 24(1) of the *Charter*. She went on to state that the complexity of the issues "understandably resulted in submissions which have not comprehensively addressed the issues in this case."

McLachlin et al. noted that the lower courts and Ms. Ernst herself assumed that, by its terms, *ERCA* section 43 plainly and obviously barred Ms. Ernst's entire claim. While the justices acknowledged that those assumptions may ultimately prove correct, in their opinion, it was not plainly and obviously so at this stage given the evidence on the record.

On reaching this conclusion, McLachlin et. al would have allowed the appeal without having to consider the constitutionality of *ERCA* section 43.

ALBERTA COURT OF APPEAL

***Goodhart v Alberta Energy Regulator*, 2017 ABCA 22**
Application for Extension of Time to Appeal – Application Denied – AER Does not Owe Private Duty of Care

In *Goodhart v Alberta Energy Regulator,* the ABCA considered Mr. Goodhart's application seeking an extension of time to file his appeal of an ABQB decision striking his claim against the AER.

<u>ABQB Decision</u>

Goodhart claimed the AER was responsible for exposing his late wife and adult children to toxic chemicals. The ABQB struck the claim on the basis that it failed to disclose a cause of action, namely that the AER owed a private duty of care to the Goodharts. The ABQB decision relied on the ABCA reasoning in *Ernst v. Encana Corp.* (recently affirmed by the SCC) that the AER does not have of private duty of care to individuals.

The ABQB also held the claim was barred by the immunity clause contained in section 27 of the *Responsible Energy and Development Act* ("*REDA*") (equivalent to the previous *ERCA* section 43, discussed above).

REDA section 27 provides:

> 27 No action or proceeding may be brought against the Regulator, a director, a hearing commissioner, an officer or an employee of the Regulator, or a person engaged by the Regulator, in respect of any act or thing done or omitted to be done in good faith under this Act or any other enactment.

<u>ABCA Decision</u>

The ABCA denied the extension request on the basis that the appeal had no prospect of success if allowed. Paperny J.A. held that the ABCA decision *Ernst v. Encana Corp.* makes clear that the AER does not owe of private duty of care to individuals. Justice Paperny ruled that the principles articulated by the ABCA in the *Ernst* decision applied directly to this case to similarly bar Goodhart's claim. Therefore the appeal had no prospect of success.

<u>Test for Extending Time to Appeal</u>

In denying the requested extension, the ABCA considered the relevant test and whether it was expected to settle an important point of law. The ABCA laid out the applicable test set out in *Cairns v Cairns*, [1931] 4 D.L.R. 819 (ABCA), which requires the court to consider the whether:

1. there was there a *bona fide* intention to appeal while the right to appeal existed;
2. there is an explanation for the delay;
3. the appellant has taken the benefits of the judgment; and
4. the appeal has a reasonable chance of success if allowed to proceed.

A court may also consider whether the proposed appeal is likely to settle an important point of law or where there are unique and special circumstances and it is in the interest of justice to grant an extension.

With respect to the first *Cairns* factor, the ABCA held that it was not clear whether there was a bona fide intention to appeal. However, the ABCA denied the requested extension on the grounds the appeal had not prospect of success if allowed, as discussed above.

Morin v. Alberta (Utilities Commission), 2017 ABCA 20

In this decision, the ABCA considered an application for permission to appeal and a stay of AUC Decision 21291-D10-2016 (the "AUC Decision"). The AUC Decision was the last of a series of AUC decisions granting extensions to TransAlta for the completion of an approved transmission rebuild project.

<u>ABCA Decision</u>

The ABCA denied permission to appeal on the basis that the appeal was not prima facie meritorious.

The ABCA noted that an AUC decision to grant an extension is a discretionary decision dealing with the AUC's own process. The ABCA held that the applicable standard of review of an AUC decision granting an extension request is reasonableness. Courts will show considerable deference to such an AUC decision.

The ABCA also noted that a number of complaints raised by the applicants about earlier AUC decisions constituted collateral attacks on those decisions, which were never appealed.

With respect to the requested stay, the ABCA noted the point was moot as construction had already begun when the application was heard.

The applicants were members of the Enoch Cree Nation and are Certificate of Possession Holders. However, the Enoch Cree Nation itself opposed the application.

In denying the appeal, the ABCA noted that the grounds of appeal were not entirely clear, but that "as far as can be discerned" were as follows:

1. a permit under section 28(2) of the *Indian Act*, RSC 1985, c I-5, should have been obtained by TransAlta prior to entering into or carrying out the work;

2. the AUC ought not to have considered TransAlta's request for a time extension without giving notice of the application to the applicants; and

3. various earlier decisions of the AUC or its predecessors ought not to have been granted.

<u>Test for Permission to Appeal</u>

Also, in denying the appeal, the ABCA noted that the applicable test for permission to appeal an AUC decision is contained in the *Alberta Utilities Commission Act* ("*AUCA*") section 29. For permission to be granted, an applicant must show that the question of law or judication raises a serious, arguable point. In addition, the court among the factors to be considered on a request for permission to appeal are whether:

1. the appeal is prima facie meritorious, or on the other hand, whether it is frivolous (at this stage the ABCA must consider the standard of appeal should leave be granted); and

2. the question is of significance to the action.

ALBERTA ENERGY REGULATOR

Bonavista Energy Corporation: Regulatory Appeal of Well Licences and an Application for a Pipeline, 2017 ABAER 001
Regulatory Appeal – Natural Gas Facilities – Pipeline Application

Background

On June 8, 2015, Bonavista Energy Corporation ("BEC") submitted to the AER nonroutine applications for two horizontal gas wells to be drilled from the surface location of two existing wells (the "15-22 Site") but to different bottomhole locations. The AER approved the well applications and issued well licences 476069 and 476070 to BEC on July 10, 2015 (the "Well Licences"). No statements of concern were received by the AER prior to it issuing the Well Licences.

On June 29, 2015, BEC applied for approval to construct and operate a pipeline to transport gas from the site of the existing and approved wells to an existing compressor station ¾ of a kilometre away.

Patrick and Patricia Alexander and Evelyn Heringer (collectively, the "Alexanders") filed a request for regulatory appeal of the Well Licences on July 23, 2015. On July 26, 2015, the Alexanders filed a statement of concern with respect to BEC's pipeline application.

On September 17, 2015, the AER decided to hold a hearing for the pipeline. However, that hearing was delayed pending the AER's decision regarding the request for the regulatory appeal of the Well Licencnes. On May 9, 2016, the AER granted the request for a regulatory appeal and decided to hold a combined hearing on the pipeline application and regulatory appeal of the Well Licences.

The hearing was held in October 2015.

Parties' Submission

While the Alexanders did not object to the need for the wells, they objected to the extension of the lease for the existing wells to accommodate the space for the two additional wells. The Alexanders submitted that the lease extension resulted from poor planning on the part of BEC, and that they should not have to pay the price of losing more land and added inconvenience to their farming operations.

The Alexanders also presented evidence on other sites that the Alexanders submitted were similar in size to the original lease for the 15-22 Site and accommodated 3-4 wells.

The Alexander's raised other concerns regarding:

- the impact of increased traffic caused by the project;
- the potential effects on water wells;
- noise and light effects during construction; and
- the esthetic impact of the project and negative impact to property values.

BEC presented evidence that, on a per well basis, the extended lease for the 15-22 Site would be similar, or smaller to, the area of comparable sites referenced by the Alexanders.

With respect to the effect on water wells, BEC submitted that it completes a surface casing depth design in accordance with AER Directive 008: *Surface Casing Requirements*. Specifically, BEC noted that for the for 400 metres in depth, which it submitted is deeper than water wells, it uses water based drilling fluid, sets a surface casing string, and then cements the surface. BEC conducts water testing on concerns being raised by landowners. The water testing is done by a qualified third party and compared against baseline measurements. Any issue are remedied at BEC's sole cost.

With respect to the pipeline, the Alexanders submitted that the existing 6-inch pipeline from the current 15-22 site had been installed only three years ago, along the same route as the proposed pipeline. They submitted that they were concerned with the proliferation of oil and gas facilities in their area and that the need for a second pipeline reflected poor planning by BEC.

AER Decision Denying Regulatory Appeal

The AER stated that it does not have requirements for, nor does it regulate, county road use.

The AER held that BEC's proposed mitigation measures were sufficient to address the Alexander's concerns related to noise and visual impact. The AER acknowledged the Alexander's concerns regarding impact to property values, but noted that awarding monetary compensation was beyond the AER's jurisdiction.

The AER held that BEC's practices to protect drinking water during drilling complies with AER requirements. The AER also held that BEC's water testing protocol sufficiently addresses any potential concerns that may arise during the operational lives of the proposed wells.

The AER accepted BEC's evidence that the rig in question had been used in the majority of similar wells drilled in the area. The AER concluded that BEC had demonstrated that the licenced surface location of the wells required the lease extension to meet safety and regulatory requirements to drill the wells for the proposed rig.

The AER also held that BEC's stated commitments to mitigate the Alexanders' concerns regarding reclamation and farming would allow the Alexanders to continue farming in much the same way as they do currently.

AER Decision Denying Pipeline Application

The AER denied BEC's pipeline application.

The AER found that due to the rapid reduction in production volume expected to occur from the proposed new wells, the need for extra pipeline capacity would be relatively short-lived. The AER noted that within six to seven months, production rates will decline enough to eliminate the need for an additional pipeline to handle production from the four wells at the 15-22 Site. The AER found that having the additional pipeline available would only minimally expedite production of gas from the wells at the 15-22 Site. The panel held that denying the pipeline application would not result in lost production volume, but merely some volume deferred for later realization.

Given the AER's finding that there was only a short term need for additional pipeline capacity, the AER held that short-term economic benefit to BEC did not justify the adverse impact to landowners. The AER's ruling was on a without prejudice basis to BEC with respect to future projects.

ALBERTA UTILITIES COMMISSION

ENMAX Energy Corporation 2016-2018 Energy Price Setting Plan (Decision 20448-D01-2017)
Electricity Distribution – Rates – Regulated Rate Option – Energy Price Setting Plan

In this decision, the AUC considered ENMAX Energy Corporation ("ENMAX")'s application (the "Application") requesting the AUC approve its proposed Energy Price Setting Plan ("EPSP"). In the Application, ENMAX proposed an EPSP consisting of the following principle elements:

a) for its Regulated Rate Option ("RRO") customers, ENMAX proposed a block process for the procurement of forward market electricity products, using a daily target pricing mechanism and a weekly target volume methodology;

b) to cover the costs of procurement, ENMAX proposed using a base energy charge that incorporates the prices of the forward market electricity products it has procured (the "RRO Energy Charge");

c) a method of compensation:

   i. to compensate ENMAX for the risk associated with the differences between the RRO Energy Charge and the actual prices paid by ENMAX to provide electricity to RRO customers;

   ii. to compensate ENMAX for the risk associated with the differences between the volume of the forward market electricity procured and the actual volume used by RRO customers;

   iii. to provide ENMAX the opportunity to earn a reasonable rate of return in providing electricity to its RRO customers; and

   iv. to allow for ENMAX to recover all other costs associated with the EPSP, since ENMAX was required legislatively required to provide RRO services; and

d) re-opener and EPSP amendment provisions.

<u>Redacted Parts of Decision</u>

Due to the commercially sensitive nature of much of the information ENMAX provided as part of its application, the following parts of the decision were largely or completely redacted:

a) Target Volume and Target Price;

b) Deemed Trades;

c) Backstop procurement;

d) Details of procurement process; and

e) Over-the-counter trades.

<u>Load Forecast and Procurement Protocol</u>

ENMAX proposed a continuation of its existing load forecast methodology, which is based on the following forecast parameters:

1. net forecasted growth or attrition rate (as a percentage) for eligible customers;
2. estimated site counts for eligible customers;
3. load shape for eligible customers;
4. normalized daily temperatures for the delivery month;
5. historical hourly load for eligible customers; and
6. historical unaccounted for energy and line losses.

No party objected to ENMAX's requested load forecasting methodology. The AUC approved ENMAX's forecasting methodology as applied for. The AUC stated that it is incumbent upon ENMAX and in its best interests to forecast its load as accurately as possible, in order to minimize its commodity risk exposure.

With respect to energy procurement, the Consumer's Coalition of Alberta (the "CCA") proposed an auction procurement process as an alternative to ENMAX's proposed block procurement process, to be carried out by a dedicated trader. In support of its alternative auction proposal, the CCA identified concerns with ENMAX's block procurement, including:

a) the actual or perceived lack of independence of a dedicated trader that would be acting for both the RRO and ENMAX's wholesale trading unit;

b) the potential for extensive use of self-supply; and

c) the need for a third-party reviewer and the costs associated with block procurement.

While the CCA supported its proposal, in part, by focusing on the costs associated with block procurement, the CCA did not submit evidence showing that an auction process would be less costly. The AUC held that there was insufficient evidence on the record to determine whether auctions are more cost effective than block procurement.

The AUC concluded that the CCA (supported by TransCanada Energy) did not provide sufficient evidence to demonstrate that auctions would result in cost savings for ENMAX's RRO customers, that there would be adequate interest among suppliers to make auctions for ENMAX's RRO load viable, or that there would not be significant delays in implementation of ENMAX's new EPSP if auctions were to be adopted. Accordingly, the AUC denied the CCA's requested alternative for ENMAX to employ an auction procurement process. The AUC accepted ENMAX and the UCA's positions that an auction process is not required at this time.

Incentive Mechanism

The AUC denied the incentive sharing mechanism component of ENMAX's proposed EPSP.

The AUC agreed with the UCA's submission that the AUC's rationale in rejecting the incentive sharing mechanism proposed by Direct Energy Regulated Services ("DERS") in Decision 2941-D01-2015 is equally applicable to ENMAX. The AUC noted that both ENMAX's proposed EPSP and DERS' EPSP employ block procurement and the setting of target prices and target volumes.

The AUC held that it is not necessary to provide a procurement incentive for ENMAX because it is in the interests of both ENMAX and its customers for ENMAX to procure energy at the lowest price possible.

External Independent Review

ENMAX proposed to engage NGX as an independent third party to review and verify ENMAX's monthly energy rate filings prior to such filings being submitted to the AUC. ENMAX estimated annual costs of $75,000 for NGX's services.

The UCA opposed ENMAX's proposal. The UCA's reasons for its opposition included that ENMAX (and its shareholders) would be the primary beneficiaries from external review, intervener groups could provide the same function if provided access to such information, and that there was already sufficient testing by the AUC and ongoing third-party monitoring in procurement activities. The UCA submitted that, given the above, the costs of the proposed NGX review were not justified. The UCA submitted that, in the alternative, ENMAX shareholders should bear the cost of NGX's review.

The AUC denied ENMAX's proposed engagement of NGX. The AUC found that ENMAX staff were able to perform the function required to review the trade information to be including in monthly filings. The AUC held that it is ENMAX's responsibility to ensure the accuracy of its monthly filings.

Reasonable Return Compensation

The AUC directed that ENMAX maintain the reasonable rate of return amount approved in Decision 2941-D01-2015 of $2.44/MWh.

The AUC concluded that in the absence of any reopener request or proposal from ENMAX to update the reasonable return amount every year to incorporate the previous year's Rule 005 financial information, there was no basis to depart from the previously approved value. The AUC therefore denied ENMAX's request to update the after-tax reasonable return amount to $2.49/MWh.

Risk Compensation

ENMAX and the UCA both proposed credit risk compensation ("CRC") methodologies consisting of a variable component and a fixed component.

With respect to the variable component of the CRC methodology, both proposals used the sum of the commodity gains (losses) for the previous 12-months as a starting point. In ENMAX's proposed methodology, the sum of the gains/losses is divided by the sum of the sales volume (in MWh) over the same previous 12-month period.

The UCA proposed a variable CRC component that uses the sum of commodity gains/losses divided by the sum of commodity revenues. The resulting percentage is multiplied by the base energy charge (which is a $/MWh figure), to arrive at a scaled base energy charge amount, measured in $/MWh, to be included as part of the total CRC.

The AUC noted that the UCA's proposed variable CRC component responds to changes in the base energy charge, whereas ENMAX's proposal would not. The question before the AUC was therefore whether the variable component of the CRC should respond to changes in the level of base energy charge.

The AUC determined that the UCA's proposal was preferable. The AUC considered the base energy charge to be reflective of forward electricity prices. In support of this finding, the AUC referenced previous AUC decisions that noted the importance that any changing market conditions be reflected in the variable CRC.

With respect to the fixed component of the CRC, the AUC directed ENMAX to adopt the "Beblow method." In Decision 2941-D01-2015, the AUC previously directed DERS and EEA to adopt the Beblow method, which was considered in detail in that decision and summarized below.

The fixed (risk cycle) component of the CRC is required because as the risk in the market increases and decreases over time and the adaptive component lags behind it, there is a chance that an RRO provider may be in a loss position at the end of the EPSP. Therefore, additional compensation may be required to target profit neutrality, regardless of the EPSP end date.

The Beblow method employs a fixed risk cycle component ($/MWh) calculated using historical data at the start of the EPSP and then updated each year. The calculation can be summarized as follows:

a) Sum commodity gains and losses including total CRC for the relevant time period;

b) If the net dollar value from step 1 is positive the Risk Cycle CRC would simply equal $0.00/MWh for the next twelve months. If the net dollar value from step 1 is negative, the dollar value would then be divided by the sum of the actual settled energy for the same time period and made absolute (i.e. turned into a positive number) in a $/MWh; and

c) the resulting $/MWh value for Risk Cycle CRC would be included in the calculation of the monthly RRO rate.

The AUC noted that the Beblow method is better suited to maintain a utility's profit/loss neutrality over the term of an ESPS. The AUC rejected ENMAX's proposed methodology that employs a fixed CRC component of $0.44, noting that it would result in a greater chance of over-collection.

FortisAlberta Inc. 2015 PBR Capital Tracker True-Up (Decision 21538-D01-2017)
Rates – Performance Based Regulation– Capital Tracker True-up Application

In this decision, the AUC considered FortisAlberta Inc.'s ("Fortis") 2015 capital tracker true-up application.

Capital Tracker and K-Factor Overview

In Decision 2012-237 (the "2012 PBR Decision"), the AUC set out the first generation PBR framework and approved PBR plans for certain distribution utilities, including Fortis. In that decision, the AUC approved a flow-through rate adjustment mechanism to fund certain capital-related costs, referred to as a "capital tracker."

Programs or projects approved for capital tracker treatment are included in a utility's annual revenue requirement adjustments, as determined by the applicable PBR plan formula. The revenue requirement associated with approved capital tracker projects is collected from ratepayers by way of a flow-through "K factor" adjustment.

The 2012 PBR Decision also set out the three criteria a program or project must meet to be eligible for capital tracker treatment, namely:

1. the project must be outside the normal course of on-going operations ("Criterion 1");
2. ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party ("Criterion 2"); and
3. the project must have a material effect on the company's finances ("Criterion 3").

Criterion 1 requires a two stage assessment of each project or program for which capital tracker treatment is requested. At the first stage (project assessment), an applicant must demonstrate the project is:

a) required to provide utility service at adequate levels and, if so,

b) that the scope, level and timing of the project are prudent, and the forecast or actual costs of the project are reasonable.

At the second stage, an applicant must demonstrate the absence of double-counting (the "Accounting Test"). The Accounting Test requires an applicant to demonstrate that the associated revenue provided by the PBR formula will be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project in question.

With respect to Criterion 2, a growth-related project will generally qualify where an applicant demonstrates that customer contributions and incremental revenues are insufficient to offset the project's cost.

The materiality threshold in Criterion 3 requires that each individual project affect the revenue requirement by four basis points. On an aggregate level, all proposed capital trackers must have a total impact on revenue requirement of 40 basis points.

Summary of AUC Holdings

The AUC summarized its significant holdings in this decision as follows:

- Fortis' proposed grouping of projects into programs is reasonable;
- the need for the capital tracker projects or programs in the 2015 true-up is confirmed;
- except for the Distribution Control Centre ("DCC")/Supervisory Control and Data Acquisition ("SCADA") project (the "DCC/SCADA Project"):
    - o the actual scope, level, timing and costs of each of the projects were prudently incurred and continue to meet the requirements of the Accounting Test under Criterion 1;
    - o the previously-approved capital tracker projects continue to meet the requirements of Criterion 2; and
    - o the capital tracker projects continue to meet the first tier materiality requirements of Criterion 3.
- However, the AUC required additional information to assess the scope, level, timing and actual costs of the

DCC/SCADA project against the project assessment requirement of Criterion 1. Therefore, the AUC held that it will reassess that project as part of its consideration of Fortis' compliance filing to this decision.

Criterion 1: Project Assessment

For previously approved capital trackers, there is a presumption of prudence regarding the first part of Criterion 1.

The AUC noted that for projects previously confirmed meeting Criterion 1 in prior capital tracker decisions that – in the absence of evidence that the project is no longer required – there is no need to reassess the necessity of the project under Criterion 1. However, the AUC held that for capital tracker true-up applications, it does assess the scope, level and timing of each project on an on-going basis for prudence, as required by the Accounting Test under the second part Criterion 1.

The second part of the Criterion 1 assessment considers whether the actual scope, level, timing and costs of the project are prudent. The variance between the actual project costs and the approved forecast is a relevant factor in this respect, but not determinative if an applicant provides a reasonable explanation for such variances.

The AUC provided the following table showing previously approved capital tracker programs or projects and the forecasted vs. actual costs for each project in 2015:

Program/project name	**2015 approved forecast**	**2015 actual**	**Variance**
A. Projects or programs for which no objections were raised			
Substation Upgrades program	18.7	6.7	(12.0)
Distribution Line Moves program	16.4	21.2	4.8
B. Projects or programs for which objections were raised			
Cable Management program	6.0	8.5	2.5
Customer Growth program	139.8	119.3	(20.5)
Urgent Repairs, Worst Feeders and Compliance/ Reliability programs	27.3	26.4	(0.9)
Pole Management program	30.8	43.0	12.2
Distribution Control Centre/SCADA project	4.6	5.2	0.6
B. AESO Contributions Program			
AESO Contributions Program	97.7	54.8	(42.8)

Projects/Costs Objected to by Interveners

The Consumers Coalition of Alberta ("CCA") noted its concerns regarding the significant variance between the approved forecast and the actual 2015 program costs for certain projects and on the aggregate level.

However, with the exception of the DCC/SCADA Project, the AUC held that the 2015 actual costs were prudent and that the variance explanations provided by Fortis were reasonable.

DCC/SCADA Project

The AUC noted that $0.7 million of the actual 2015 costs included the costs to install 13 reclosers that were not completed in 2014. The AUC further noted that It was not apparent from the 2015 true-up application whether Fortis had installed all of the 2014 and 2015 reclosers as planned, or if it considers that there are still outstanding reclosers to be replaced in subsequent years.

The AUC noted that when it approved the final 2014 actual costs of the DCC/SCADA project as prudent, it expected that, other than any exceptions noted by Fortis in the variance explanations, work on this project had generally proceeded according to forecasted scope and schedule. Although the capital expenditures approved as prudent in the 2014 application were generally in line with forecasts, the AUC expressed concern that the amount of work completed for the stated cost had not in fact been completed.

In light of the above, the AUC held that the business case in support of the actual capital expenditures on the DCC/SCADA project did not facilitate a complete review of the costs for 2015. The AUC directed that Fortis provide the following information in its compliance filing to assist the AUC with its evaluation of the scope, level, and timing of the work carried out for the DCC/SCADA project for 2015:

Year	**Recloser replacement (forecast)**	**Recloser replacement (actual)**	**Unit cost (forecast)**	**Unit cost**
2014	25	10	*[Fortis to Complete]*	*[Fortis to Complete]*
2015	25	33	*[Fortis to Complete]*	*[Fortis to Complete]*

Additionally, the AUC directed that Fortis provide a reconciliation of the scope of work corresponding with the forecast cost for the DCC/SCADA project in a given year, in addition to any variance explanation. This direction applies to the compliance filing and in all subsequent capital tracker true-up applications.

AESO Contributions Program

The AUC stated that it understands that projects giving rise to AESO contribution amounts are generally initiated by Fortis on the basis of its assessment of the needs of its end-use customers. Fortis also determines the amount of Demand Transmission Service ("DTS") contract capacity for each project.

The AUC noted that while the AESO determines the amount of investment Fortis is eligible for under its tariff, the AESO's determination is essentially mechanical because it reflects the DTS contract levels and contract terms that Fortis requests. The Transmission Facility Owner ("TFO")'s execution of the connection project determines the cost of the project used for the contribution calculation.

The AUC also noted that AESO contribution amounts on specific projects are subject to ongoing update and revision, as cost estimates change over time during execution. Costs for a TFO project are not considered final until they have been approved by the Commission in the associated Direct Assigned Capital Deferral Account ("DACDA") application. The result of this on-going adjustment is that the AUC is not able to evaluate the scope, level, timing, and prudence of Fortis' 2015 expenditures relating to AESO Contributions programs.

The AUC noted that, ideally, the actual contribution amounts paid by Fortis should ultimately correspond to the actual contributions that AltaLink (the TFO) includes in its rate base in respect of projects completed on behalf of Fortis. However, the AUC observed that final amounts of 2017, the last year of the current PBR plans, may not be known until 2020 or later, long after that 2013-2017 generation of PBR plans have expired.

AUC Decision 20414-D01-2016 established the new PBR plan framework and parameters for the next generation PBR term for 2018-2022. The treatment of capital projects is significantly different than the present capital tracker treatment and K-factor collection mechanism (a summary of Decision 20414-D01-2016 is provided in the Oct/Nov/Dec 2016 Energy Regulatory Report). Under the next generation PBR plans, most capital projects will be funded through a K-bar parameter, for which the associated revenue requirement is determined with reference to the I-X mechanism. This form of treatment for capital projects departs from the largely flow-through cost of service based capital treatment afforded to eligible capital tracker projects in the 2013-2017 PBR term.

The AUC therefore directed Fortis to provide a proposal for determining final actual AESO Contributions program amounts for each of the years 2013-2017, along with a proposal for incorporating these final amounts into the going-in rates and base K-bar for the next PBR term.

Criterion 1: Accounting Test

The AUC explained that the purpose of the Accounting Test is to determine whether a proposed capital tracker project is outside the normal course of the company's ongoing operations. This is achieved by demonstrating that the associated revenue provided under the I-X mechanism would not be sufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the project or program.

Fortis used the following values for the purpose of the Accounting Test set out in its application:

2015 I-X index	1.49%
2015 Q factor	2.31%
Weighted Average Cost of Capital ("WACC")	6.85%

The AUC approved Fortis' values for WACC, I-X and Q factor assumptions (as shown in above table) as filed.

The AUC found that Fortis' Accounting Test model sufficiently demonstrated that the actual expenditures for each proposed capital tracker project were, or a portion was, outside the normal course of the company's ongoing operations, as required to satisfy the accounting test component of Criterion 1.

Criterion 2: Replacement, Externally Driven, or Growth Related Project

In addition to asset replacement projects and projects required by an external party, a growth-related project will, in principle, satisfy the requirements of Criterion 2 where it can be demonstrated that customer contributions, together with incremental revenues allocated to the project on some reasonable basis, when added to the revenue provided under the I-X mechanism, are insufficient to offset the revenue requirement associated with the project in a PBR year.

The AUC provided the following summary table showing the driver for each project included in Fortis' application:

Project name	Criterion 2 project type
Customer Growth program	Growth
AESO Contributions program	Externally driven
Substation Associated Upgrades program	Externally driven
Distribution Line Moves program	Externally driven
Urgent Repairs program, Worst Performing Feeders program, and Compliance, Safety, Aging Facilities, and Reliability program	Asset replacement/life extension
Distribution Capacity Increases program	Growth
Metering Unmetered Oilfield Services project	Asset replacement
Pole Management program	Asset replacement/life extension
Cable Management program	Asset replacement/life extension
Distribution Control Centre/SCADA project	Other (safety/reliability)

The AUC noted that because the drivers of each project or program included in Fortis' 2015 capital tracker true-up had not changed from the previously approved capital tracker projects, it wasn't necessary to undertake a reassessment of such projects against the Criterion 2 requirements.

Criterion 3: Materiality

Having concluded that the proposed capital tracker projects/programs were outside the normal course of business under Criterion 1, the AUC considered whether the proposed capital tracker projects had a material effect on Fortis' finances (Criterion 3).

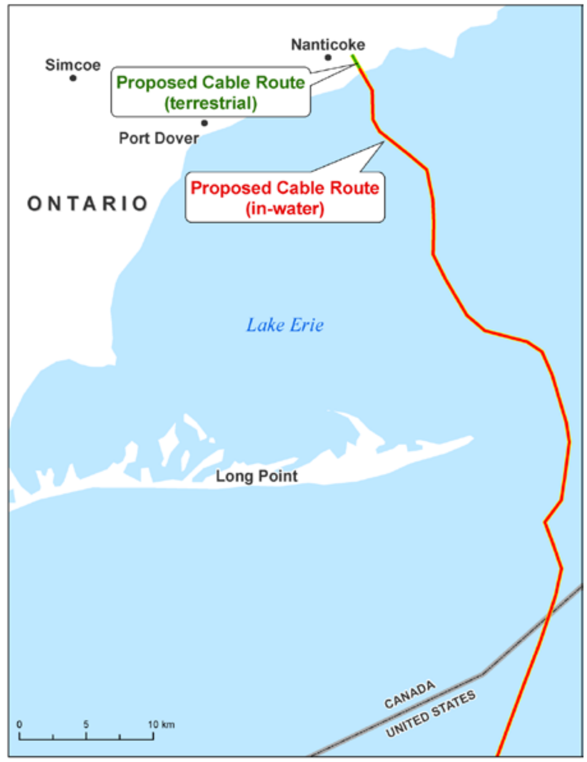
As discussed above, the materiality threshold in Criterion 3 requires that each individual project affect the revenue requirement by four basis points. On an aggregate level, all proposed capital trackers must have a total impact on revenue requirement of 40 basis points.

The AUC concluded that it was generally satisfied that in its application, Fortis had properly interpreted and applied the Criterion 3 two-tiered materiality test. Subject to the approval of the 2015 costs for the DCC/SCADA project, the AUC found that all of Fortis' proposed capital tracker projects/programs satisfy the materiality test under Criterion 3.

NATIONAL ENERGY BOARD

Reasons for Decision: ITC Lake Erie International Power Line (EH-001-2015)
Electricity Transmission Line – International Power Line

In this NEB decision, the NEB found that the Lake Erie Connector international power line project (the "Project") to be in the public interest and to be required by the present and future public convenience and necessity. Subject to Governor in Council ("GC") approval, the NEB directed that a Certificate of Public Convenience and Necessity ("CPCN") be issued for the Project.



Project and Application Overview

On May 22, 2015, ITC Lake Erie filed an application under section 58.16 of Part III.1 of the *National Energy Board Act* (the "*NEB Act*") requesting a CPCN for the Project.

The proposed Project is a transmission line for the transfer of electricity between Nanticoke, Haldimand County, Ontario and Erie County, Pennsylvania, United States. The proposed route includes a crossing of Lake Erie. The Project consists of:

- approximately 117 kilometre 1,000 megawatt ("MW") ±320 kilovolt high-voltage direct current ("HVDC") bi-directional electric transmission interconnection;
- a total of 48.1 km length for the Canadian portion of the Project, which includes 46.8 km constructed under the lakebed of Lake Erie; and
- two HVDC converter stations and AC lines to connect to the existing electricity grid.

ITC Lake Erie estimates the capital cost of the project to be about $1 billion USD. The Canadian portion of the Project is estimated to cost $543,536,066 CAD.

The Project will connect the Ontario electric system, managed by Ontario's Independent Electricity System Operator (the "IESO"), to the US mid-Atlantic and Midwest (the "PJM System"). The proposed Project is proposed as a merchant line that will be supported by commitment from transmission customers who will purchase capacity on the line. ITC Lake Erie submitted that neither Ontario nor PJM System customers will be required to support any costs for the construction, operation, or maintenance of the Project.

Economic Feasibility and Need for Project

The NEB explained that in making its determination on the economic feasibility of a proposed international power line ("IPL") and related facilities, it assesses the need for the IPL and the likelihood of the IPL being used at a reasonable level over its economic life. The NEB Board considers evidence regarding the supply of electricity that will be available to be transported on the IPL, any transmission contracts underpinning the IPL, and the availability of adequate markets to receive electricity delivered by the IPL.

With respect to the need for the Project, the NEB held that:

- the Project would improve power system reliability and trade efficiency between the Ontario and the PJM System;
- the Project is responding to market need; and
- the applicant had demonstrated sufficient benefits to the power system and economic efficiency.

Impact to System Reliability

The NEB went on to assess the Project's impact on reliability of the Ontario electric system and on neighbouring jurisdictions. Specifically, in relation to the Project's impact on reliability, the NEB considered whether:

- the elements in the electric system remain within their thermal limit;
- the system voltage remains within its limits in steady state for pre- and post-contingency conditions;
- there is transient stability in the system so that it remains stable following a major disturbance;
- the short-circuit levels remain within the system's acceptable levels; and
- the incorporation of the project would have an impact on congestion.

The NEB also considered the Project's impact on tie lines between Ontario and Manitoba.

As part of the application, ITC Lake Erie submitted a comprehensive System Impact Assessment ("SIA"), on which the NEB relied in assessing the Project's impact on the Ontario system and neighbouring systems.

The NEB noted that the Project provides a direct HVDC connection between Ontario and the PJM System. The NEB found that enhancing the number of transmission facilities in the region enhances adequacy, a paramount aspect of reliability.

With respect to security, the NEB noted that the SIA indicated that the incorporation of the Project into the existing electric power system would not yield any thermal or voltage violations, would not affect the stability of the electric system during transient conditions nor would the short circuit level increase significantly.

The NEB was satisfied with the SIA's assessment regarding security. Specifically, the SIA indicated that the incorporation of the Project into the existing electric power system would not compromise security.

The NEB held that it was satisfied the Project would not compromise the transmission of electric power among neighbouring jurisdictions.

<u>Impact to Manitoba System</u>

Manitoba Hydro raised concerns that there was a lack of consultation by the IESO in conducting the SIA.

The NEB held that the IESO, as the system operator for the area affected by the Project, was best placed to evaluate the impacts on the overall system, including impacts on neighbouring jurisdictions. The NEB also noted that the IESO is obligated by its statutory responsibilities to consider the impact of any project in Ontario over the tie lines that connect Ontario with neighbouring jurisdictions.

The NEB held that the SIA and other technical analysis had sufficient depth and breadth to reasonably demonstrate that the Project would have a marginal impact on the Manitoba and Minnesota tie lines.

<u>Aboriginal Matters: Enhanced Aboriginal Engagement Process</u>

The NEB explained that, through provision of its Enhanced Aboriginal Engagement ("EAE:") process, the Board encourages Aboriginal groups to engage with the applicant so that their interests and concerns are identified early, considered by the applicant, and potentially resolved before the application is filed. The NEB noted that the applicant is often in the best position to respond to such concerns.

The NEB explained that its Enhanced Aboriginal Engagement ("EAE") process is intended to assist Aboriginal groups to understand the NEB's regulatory process and how to participate in it. The EAE process involves proactive contact by the NEB and project proponents with Aboriginal groups who may be affected by a proposed project. Aboriginal groups engaged through the EAE process include, but are not limited to, those groups that have publicly claimed or asserted the right to use the land in the Project area for traditional uses.

The NEB reviews the completeness of the list of potentially affected Aboriginal groups identified by a project applicant. The NEB may identify other groups who may be potentially impacted by the proposed project. The NEB's list of groups is sent to the Government of Canada's Major Projects Management Office ("MPMO") or Natural Resources Canada (NRCan), and if applicable the list is updated. This list is called the Crown List.

The NEB sends a letter package which includes a summary of the project and how to obtain more information, to each potentially affected Aboriginal group on the Crown List. After issuing the letter package, NEB staff follow up with phone calls to each of the Aboriginal groups to confirm receipt, respond to questions Aboriginal groups may have, and arrange information meetings on request.

<u>ITC Lake Erie Aboriginal Engagement</u>

ITC Lake Erie submitted that its initial early engagement activities took place in August and September of 2013 with the two Aboriginal groups in the immediate vicinity of the proposed project. Those groups were the Mississaugas of the New Credit First

Nation ("MNCFN") and Six Nations of the Grand River ("Six Nations").

The MNCFN and Six Nations supported the Project and noted that they both continue to engage with ITC Lake Erie on all aspects of the Project.

The MNCFN and Six Nations stated that they were satisfied with the consultation process. Both groups expressed interest in assessing the skilled trade opportunities and other potential economic development opportunities resulting from the Project. Neither the MNCFN nor the Six Nations filed an application to participate in the hearing.

Land and Environmental Matters

The NEB found that fish mortality could result from the trenching/blasting and jet plow/water jetting conducted for the in-water part of the Project. However, the NEB held that given the proposed mitigation measures, direct mortality, if any, associated with these activities would likely be limited to a few individuals. The NEB found that therefore, the magnitude of residual effects is anticipated to be low and the Project is not expected to result in effects to aquatic Species At Risk.

Fish habitat alteration could result from trenching/blasting and jet plow/water jetting. However, the NEB held that the use of hydraulic direction drilling at the shoreline would result in minimal impacts to fish habitat (the small area of the exit/receiving pit, and small area of excavated sump pit). The NEB found that any fish habitat impacted by the Project is low-quality fish habitat, and the alteration of such habitat would be of low magnitude, temporary, and reversible.

Cumulative Effects

The NEB also assessed the potential cumulative effects of the projects. The NEB defines cumulative effects as "adverse residual effects associated with the Project in combination with residual effects from other projects and activities that have been or will be carried out, within the appropriate temporal and spatial boundaries and ecological context."

The NEB listed the following categories of potential residual effects of the Project, including:

- physical elements – physical environment, soil and soil productivity, water and water quality, air emissions, greenhouse gas ("GHG") emissions, and acoustic environment;
- Biological elements – vegetation, aquatic species and habitat, wildlife and wildlife habitat, and species at risk; and
- Socio-economic elements – human health, employment and economy, and acoustic environment.

The NEB determined that most adverse environmental effects would be minor in nature and mostly limited to the construction period. The NEB found that these would likely be low in magnitude and their contribution to cumulative effects would be minor.

The NEB held that overall, with the implementation of ITC Lake Erie's environmental protection procedures and mitigation and the NEB's conditions, the Project is not likely to cause significant adverse environmental effects.

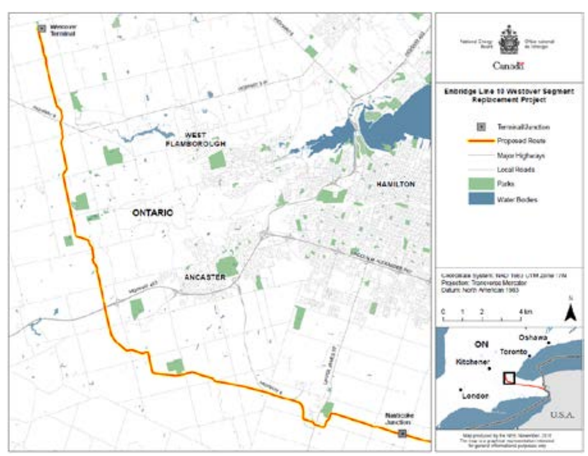
Reasons for Decision: Enbridge Pipelines Inc. – Line 10 Westover Segment Replacement Project (OH-001-2016)
Facilities Application – Pipelines

The Proposed Project

On 4 December 2015, Enbridge Pipelines Inc. ("Enbridge") filed an application (the "Application") with the NEB seeking approval to replace an existing section of the Line 10 Pipeline (the "Project").

The Project includes the decommissioning of approximately 32 km of existing 323.9 mm outside diameter ("OD") pipe (the "Existing Line") and replacing it with approximately 35 km of new 508 mm OD pipe (the "Replacement Line"). The Project extends from Enbridge's Westover Terminal to its Nanticoke Junction Facility, both near the City of Hamilton, Ontario.

Figure 1: Project Location Map



Enbridge described the Project as a routine maintenance project designed to restore a section of pipe to its original annual capacity of 11,797 m3/day. In addition, the Project is intended to alleviate landowner concerns related to increasingly frequent maintenance digs associated with the Existing Line.

NEB Decision

For the reasons summarized below, the NEB found the Project to be in the public interest, subject to:

a) 32 terms and conditions regarding the construction of the Replacement Line; and

b) 14 terms and conditions regarding the decommissioning of the Existing Line.

Economic Feasibility

No participants commented on or objected to the Project being necessary or economically feasible.

Enbridge submitted that the Existing Line has reached its conservative threshold for replacement and should be replaced rather than undergo a program of further digs, inspection and routine maintenance.

Enbridge stated the capital cost of the Project is approximately $219 million and is financed through a commercial agreement with a third-party customer.

The NEB stated that it was satisfied with the economic feasibility and available financing for the Project. The NEB found that that there is a sufficient market to absorb the volumes of crude oil that would be delivered off the Replacement Line.

Construction of Replacement Line

The NEB approved the general design of the Project facilities as appropriate for the intended use and that the facilities would be constructed in accordance with widely accepted standards for design, construction, and operation.

Decommissioning of Existing Line

The NEB approved Enbridge's approach to decommissioning of leaving the Existing Line in-place. However, the NEB imposed a condition requiring Enbridge to apply for leave to abandon the Existing Line once the Replacement Line is completed.

Environmental and Socio-Economic Impacts

Because the proposed Project is under 40 km in length, it is not considered a designated project under the *Canadian Environmental Assessment Act*, 2012 (the "*CEAA 2012*"). Therefore, the *CEAA 2012* does not require an environmental assessment under that act. However, the NEB will still consider environmental protection as part of its broader mandate under the *NEB Act*.

Specifically, the NEB completed an Environment and Socio-Economic Assessment ("ESA") as part of its review of the Project. The ESA considered both the decommissioning of the Existing Line and the construction and operation of the Replacement.

The NEB held that with the implementation of Enbridge's proposed environmental protection mitigation measures, as well as certain NEB imposed conditions, the Project is not likely to cause significant adverse environmental effects.

Consultation

The NEB concluded that Enbridge's design and implementation of its Project-specific public and Aboriginal engagement activities were appropriate for the scope and scale of the Project.

The NEB found that all Aboriginal groups potentially affected by the Project were provided with sufficient information and opportunities to make their views about the Project known to Enbridge and to the NEB.