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REGULATORY
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ENERGY REGULATORY REPORT

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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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ALBERTA ENERGY REGULATOR

Request for Reconsideration of EUB Decision 2005-079 and OSCA Approval No.10330A by George Percy and Barbara Percy
Request for Reconsideration – REDA Section 42

In this decision, the AER considered George and Barba Percys' (the "Percys") request under section 42 of the *Responsible Energy Development Act* ("*REDA*") for reconsideration of Alberta Energy and Utilities Board ("EUB" or "Board") Decision 2005-079 and of Commercial Scheme Approval No. 10030A issued to Value Creation Inc. ("VCI") for the Heartland Upgrader project (the "Heartland Upgrader Approval").

The AER concluded that the Percys did not demonstrate extraordinary circumstances that gave rise to exceptional and compelling grounds for the AER to reconsider Decision 2005-079 or the subsequent approvals. The AER therefore denied the request for reconsideration.

As further summarized below, the AER denied the Percys request for reconsideration of EUB Decision 2005-079 based on its findings that:

(a) VCI's predecessor did not make a commitment to purchase the Percys' property;

(b) VCI's predecessor had not breached any commitments made under the Voluntary Purchase and Resident Relocation Proposal ("VPRRP"), and

(c) the Percys would be afforded an opportunity to have their concerns considered by the AER hearing panel, given that the Percys would be participating in the upcoming hearing regarding the Heartland Upgrader.

<u>Background</u>

The AER explained that:

- The EUB issued Decision 2005-079 in which it approved BA Energy Inc.'s ("BA Energy") application for approval to construct and operate the Heartland Upgrader in Strathcona County, near Fort Saskatchewan.
- The application had been scheduled for a hearing to consider the project's impacts on residents and landowners' in the area. Most of the landowners and residents participating in the proceeding were members of one of two intervener groups: The Northeast Strathcona County Residents and the Astotin Creek Residents' Coalition ("ACRC").
- The Percys owned and resided on a 30-acre land parcel located about 2 km from the project and they participated in the 2005 proceeding as a member of the ACRC.
- The Board cancelled the hearing after the two residents' associations withdrew their objections based on the resolution set out in the VPRRP. The VPRRP documents were included in EUB Decision 2005-079 as Appendix 2.
- Following VCI's acquisition of BA Energy, in 2014, VCI applied to the AER for an amendment to the Heartland Upgrader Approval.
- On March 6, 2015, the AER issued the Heartland Upgrader Approval, which designated VCI as the operator of the Heartland Upgrader. The amendment also approved changes to the project within the approved project area, which were expected to significantly reduce overall emissions.
- In June 2016, VCI applied for a further amendment of its approval. It proposed to remove one of the three approved development phases, and in its place to add a clean oil refining unit to further process product into high quality diesel, hydrotreated naphtha and a premium synthetic crude oil.
- The Percys filed a statement of concern in relation to this application. The AER directed the application to a hearing by AER hearing commissioners (Proceeding ID 356).

<u>Test under Section 42 of the *REDA*</u>

REDA section 42 provides the AER's authority to reconsider a decision. It states:

> 42 The Regulator may, in its sole discretion, reconsider a decision made by it and may confirm, vary, suspend or revoke the decision.

With respect to the AER's consideration of a request to reconsider a decision pursuant to *REDA* section 42, the AER found that:

(a) as indicated in the words of *REDA* section 42, it is at the AER's sole discretion whether to reconsider one of its decisions;

(b) *REDA* section 42 does not provide an appeal mechanism, whereas other provisions of *REDA* are available for that purpose; and

(c) given the other specific appeal processes available under the *REDA*, and the need for finality and certainty in its decisions, the AER will only exercise its discretion to reconsider a decision in extraordinary circumstances and where it is satisfied that there are exceptional and compelling grounds to do so.

In this case, the AER found that the Percys did not demonstrate that extraordinary circumstances existed that provided exceptional and compelling reasons for the AER to reconsider Decision 2005-079 and the subsequent history of approvals issued in relation to the Heartland Upgrader.

Nature of Commitments under VPRRP

In their request for reconsideration, the Percys asserted that:

(a) BA Energy made a commitment, as part of the VPRRP, to ensure the Percys' property would be purchased so that they could relocate outside the Industrial Heartland;

(b) they relied on this commitment when they withdrew their objection to the Heartland Upgrader application in 2005; and

(c) BA Energy (and by extension its successor, VCI) did not honour this commitment, and therefore the Board's original decision to approve the Heartland Upgrader should be reconsidered, allegedly contemplated in the text of Appendix 2 of the decision report.

The AER concluded that these claims were not made out, based on its findings that:

(a) the VPRRP was a proposal for a framework/program that would facilitate the purchase of lands from area residents who wished to leave the Industrial Heartland and a mutual pledge to establish a process that treated departing landowners fairly and equitably;

(b) nothing in the VPRRP committed BA Energy (or anyone else) to buyout specific landowners (including the Percys) or to guarantee they were bought out; and

(c) BA Energy committed support for the initiative (which involved operators from several industries and the local municipality) to relocate residents. It did not make a commitment that all or any of the residents would be assured of that outcome.

The AER concluded that the Percys were mistaken in their characterization of both the intent of the VPRRP and of the commitment made by BA Energy to the ACRC.

BA Energy Complied with Commitments

The Percys also asserted that BA Energy failed to honour its commitment to support financially the VPRRP.

However, based on contradictory evidence submitted by VCI, the AER found that:

(a) between 2005 and 2007, BA Energy paid $300,000 to the Land Trust Society, which was established to administer the relocation program; and

(b) therefore, based on the AER's interpretation of the commitment made by BA Energy as evidenced in Decision 2005-079, BA Energy complied with its commitment under the VPRRP.

Conclusion

For the reasons summarized above, the AER decided not to reconsider Decision 2005-079.

Request for Reconsideration by Canadian Natural Resources Ltd. of AER Decision No. 20171218A – Horizon Oil Sands Processing Plant and Mine Tailings Management Plan

Request for Reconsideration – REDA Section 42 – Tailings Management Plan

In the decision, the AER considered Canadian Natural Resources Ltd.'s ("CNRL") request under section 42 of the *Responsible Energy Development Act* ("*REDA*") for reconsideration of AER Decision No. 20171218A (the "Original AER Decision") and the Commercial Scheme Approval No. 9752E (the "Approval").

Test under Section 42 of the *REDA*

REDA section 42 provides the AER's authority to reconsider a decision. It states:

> 42 The Regulator may, in its sole discretion, reconsider a decision made by it and may confirm, vary, suspend or revoke the decision.

With respect to the AER's consideration of a request to reconsider a decision pursuant to *REDA* section 42, the AER found that:

(a) as indicated in the words of *REDA* section 42, it is at the AER's sole discretion whether to reconsider one of its decisions;

(b) *REDA* section 42 does not provide an appeal mechanism, whereas other provisions of *REDA* are available for that purpose; and

(c) given the other specific appeal processes available under the *REDA*, and the need for finality and certainty in its decisions, the AER will only exercise its discretion to reconsider a decision in extraordinary circumstances and where it is satisfied that there are exceptional and compelling grounds to do so.

The AER noted that the request included an alternative to reconsideration, which the AER found to be, in essence, CNRL requesting clarification of the Approval. Therefore, the AER concluded that reconsideration of the Approval was not necessary to address CNRL's concerns in light of the clarification provided below:

(a) the AER recognized that extensive research on water-capped tailings continues and the Government of Alberta ("GOA") would be developing policy and ready-to-reclaim performance criteria for water-capped tailings deposits as a feature of closure landscapes;

(b) the AER clarified and confirmed that, with respect to clause 48 of the Approval, if the feasibility of water-capped tailings was demonstrated and the GOA implemented applicable policies permitting their use, operators could apply to the AER to amend existing approvals to seek authorization to implement water-capped fluid tailings; and

(c) in CNRL's case, clause 55 of the Approval expressly contemplated future amendment of the Approval to permit placement of water above treated or untreated tailings to create a pit lake.

The AER confirmed that CNRL could continue to plan on the basis that water-capped tailings was an option unless such methods proved unfeasible and/or GOA policy prohibited it.

Bonterra Energy Corp. – Request for Regulatory Appeal and Stay of AER Decision to Suspend Licence Nos. 0486916, 0486919, 048717
Regulatory Appeal Request – Request for Stay – Suspension of Licences – REDA Section 39(2)

In this decision, the AER considered Bonterra Energy Corp.'s ("Bonterra") request under section 39(2) of the *Responsible Energy Development Act* ("*REDA"*) for a stay of a January 5, 2018, AER Decision to Suspend Licence Nos. 0486916, 0486919, 048717 (the "Decision"). That Decision was the subject of the above-noted request for regulatory appeal.

The AER denied the Bonterra's request for a stay of the Decision for the reasons summarized below.

Test for Stay under *REDA* Section 39

The Regulator is empowered to grant a stay pursuant to section 39(2) of *REDA*. However, as stated in section 38(2), the filing of a request for regulatory appeal does not operate to stay the appealable decision.

The AER's test for a stay is adapted from the Supreme Court of Canada case of *RJR MacDonald*. The steps in the test are:

- Serious question – Undertaking a preliminary assessment of the merits of the case to determine if there is a serious question to be heard at the requested appeal.
- Irreparable harm – Determining if the stay applicant will suffer irreparable harm if the stay request is refused.
- Balance of convenience – Assessing which of the parties would suffer greater harm from the granting or refusal of the requested stay.

The AER concluded that Bonterra had not satisfied the tripartite test.

The AER stated that it would provide its further reasons for its decision on the stay request in the near future and that its decision on the regulatory appeal request would be provided in due course.

ALBERTA UTILITIES COMMISSION

ENMAX Power Corporation – 2014 Distribution and 2014-2015 Transmission Deferral Account Reconciliation (Decision 22089-D01-2018)

Deferral Account – Direct Assigned Capital Projects

In this decision, the AUC considered ENMAX Power Corporation's ("ENMAX") application for the disposition of certain 2014 distribution and 2014-2015 transmission deferral account balances (the "Application").

For the reasons summarized below, the AUC directed ENMAX to file a compliance filing to reflect the AUC's conclusions and directions in this decision, including:

(a) remove costs related to the Remington relocation project;

(b) reduce gross capital additions for specific distribution driven transmission projects ("DDTPs") to no more than the applicable Alberta Electric System Operator ("AESO") maximum investment allowance for each project; and

(c) provide revised effective dates for the disposition of the approved deferral account balances and recalculate carrying costs associated with these deferral amounts.

Application Summary

In the Application:

(a) ENMAX requested to dispose of its distribution related amounts, a net collection of $1.540 million, subject to applicable carrying costs, by way of a distribution access service ("DAS") adjustment rider; and

(b) ENMAX proposed collecting the transmission true-up by way of a one-time collection effective July 1, 2017, comprised of ENMAX's 2014-2015 deferral account shortfalls totalling $6.459 million, subject to applicable carrying costs.

ENMAX provided the following summary of the 2014 and 2015 balances of approved deferral accounts:

Table: 2014-2015 Deferral Account Balances

Deferral Account	2014 Distribution	2014-2015 Transmission
	($000)	
Direct Assigned Capital Deferral Account ("DACDA")	-	6,345.2
Cancelled projects		743.2
2013-2015 DAS adjustment rider true-up	(4,360.3)	
2014 Revenue requirement true-up	865.8	
Hearing cost reserve account	(489.1)	(629.3)
Major storms and natural disaster	3,497.7	
AUC administration fee	2,080.4	
AESO-directed tariff billing and load settlement refund	(54.5)	
Total before carrying costs	1,540.0	6,459.1
Carrying costs	818.2	440.4
Total after carrying costs	2,358.2	6,899.5

Common DACDA Matters

Adequacy of Variance Explanations

The AUC found that the materials ENMAX initially filed with the application were not sufficient to allow the AUC to assess the prudence of ENMAX's expenditures on direct assign projects.

However, the AUC acknowledged that:

(a) actual capital addition amounts for a project in a specific year may be different from the General Tariff Application ("GTA") forecast for several reasons, including the cancellation or deferral of a project; and

(b) the GTA addition forecast for a given year may not be the best baseline for examining the prudence of ENMAX's actual expenditures on specific projects.

The AUC found that the proposal to provide services ("PPS") estimate, which includes a detailed breakdown of specific line items for the estimate, is the preferred baseline for the assessment of the prudence of actuals. The AUC noted that because the PPS stage estimates were ultimately provided by ENMAX in response to information requests, the AUC and other parties had the opportunity to consider the reasonableness of project variances in relation to the completed ENMAX direct assign projects included in the application.

<u>AESO Direct Assigned System Projects</u>

Table: Applied-for AESO Direct Assigned Transmission Projects Capital Addition Amounts

Project number and name	2013-2015 Actual	2013-2015 Approved	Variance
		($)	
C20009 - Line Modifications for New Sub	14,784	5,862	8,922
C20016 - Sub Transformer Capacity Upgrade	7,036	-	7,036
C20037 - South 69 kV Conversion Phase#1	13,571,471	8,820,944	4,750,527
C20064 - South 69 kV Conversion Phase#2	-	39,424	(39,424)
C20076 - #65 Sub-South Source 240kV Transformer	37,609,406	31,888,809	5,720,597
C20084 - South 69 kV Conversion Phase#3	2,993,684	2,631,012	362,672
C20086 - DT Cable Replacement 1.83 1.85L	42,606	42,274	332
C20103 - FATD East Calgary Development	34,296,903	21,389,184	12,907,719
Total AESO direct assigned projects	88,535,889	64,817,508	23,718,381

With respect to the $37,609,406 actual capital cost ($5,720,597 above the approved forecasted costs) for Project C20076 - #65 Sub-South Source 240kV Transformer, the AUC found that:

(a) the AESO was fully aware of the delays and associated costs attributed to the Stoney Trail road contractor;

(b) the AESO had sufficient information to have determined that the in-service date for the project should be adjusted if the AESO believed that doing so would have reduced or mitigated cost variances;

(c) accordingly, ENMAX should not be held accountable for failing to pursue more aggressively an in-service date postponement to address this issue;

(d) having regard to the cost and uncertainty of litigation, ENMAX took reasonable actions with the Stoney Trail road contractor to ensure that costs that might be recoverable from that contractor were pursued; and

(e) accordingly, ENMAX's requested capital addition in respect of Project C20076 in the amount of $37,609,406 should be approved as filed.

With respect to Project C20037, the AUC approved ENMAX's requested capital addition in the amount of $13,571,471, as filed, based on the following findings:

(a) there would not have been an opportunity to mitigate increases by delaying the project to avoid winter construction because the project had a longer timeline than a standard construction season; and

(b) ENMAX made prudent decisions at the time key decisions had to be made during project planning and execution.

The AUC noted its February 22, 2017 ruling in which the AUC determined that consideration of the prudence of the transmission line portion of the FATD East Project (Project C20103), which included segments located in the service territories of both AltaLink and ENMAX, and which was constructed under AltaLink's direction, should be considered as part of AltaLink's DACDA application (Proceeding 22542).

Accordingly, the AUC approved ENMAX's applied-for aggregate capital addition amount of $34,296,903 on a placeholder basis only, subject to any adjustments that might be applied in the Commission's decision in respect of AltaLink's Proceeding 22542.

Generator Interconnection Projects

The AUC noted that it would consider the ECTP – Shepard Project in Proceeding 22542 regarding AltaLink's 2014-2015 DACDA. The AUC considered it would be more efficient to consider all aspects of the determination of customer contribution amounts related to the ECTP – Shepard Project, including the allocation of the customer contribution as between ENMAX and AltaLink, within a single proceeding.

In light of the consideration of the ECTP – Shepard Project in Proceeding 22542, the AUC approved ENMAX's applied-for aggregate capital addition amount to December 31, 2015, of $66,449,512, on a placeholder basis only.

Distribution Driven Transmission Projects

Prudence Review

Table: Distribution Driven Transmission Projects

Project number and name	**2013-2015 actual capital additions**
	($)
C20033 - #162 Sub - 138-25kV Source	17,388,770
C20038 - #36 Sub - 138-25kV Source	259,257
C20039 - #6 Sub 25kV Cap Upgrade - Bridlewood	6,080,422
C20045 - #32 Sub Cap Upgrade - Douglasdale	12,242,106
C20049 - #47 Sub Cap Upgrade - Evanston	7,488,987
C20051 - #24 Sub Cap Upgrade - E of SSC	(3,297)
C20063 - #54 Sub - S. of Cranston	26,120,601
C20067 - #5 Sub Cap Upgrade - Central South	38,634,153
C20104 - #21 Substation 13kV Breaker	650,328
C20160 - #5 Sub Cap Upgrade - Phase 4	1,620,357
C20161 - #5 Sub Cap Upgrade - Phase 5	646,572
Total distribution driven transmission projects	111,128,256

The AUC found that ENMAX's expenditures on DDTPs between 2014 and 2015 were prudently incurred. Accordingly, the AUC approved ENMAX's requested capital additions in respect of DDTPs as filed.

Maximum ENMAX transmission investment in DDTPs

In accordance with findings in Decision 22238-D01-2017, the AUC considered that investment in DDTPs should not exceed the maximum available investment under the AESO's tariff. However, the AUC found that this was not the case for the projects shown in the below table.

Table: Investment in DDTPs in Excess of Maximum

Project number	**Cumulative 2013-2015 actual net capital additions**	**Maximum transmission investment**	**Excess ENMAX transmission investment**
	($)		
C20039	1,843,939	1,811,120	32,819
C20045	1,951,323	1,884,000	67,323
C20063	9,651,802	8,941,500	710,302
C20104	619,845	608,000	11,845
Total			2,987,729

The AUC directed ENMAX, as part of its compliance filing, to reduce its gross capital additions for the above projects to no more than the applicable AESO maximum investment allowance.

Remington Relocation Project Beyond Scope of Deferral Accounts

The AUC found that:

(a) whether certain costs are subject to a deferral account treatment should be approved in advance;

(b) the costs sought to be recovered through a deferral account must reflect the scope of the previously approved deferral account; and

(c) in this case, the Remington relocation project costs were not within the scope of the cancelled projects deferral account approved in Decision 2014-347.

Based on the above, the AUC directed ENMAX to remove the costs related to the Remington relocation project in its compliance filing.

Order

The AUC directed ENMAX to submit a compliance filing by February 12, 2018.

EPCOR Distribution & Transmission Inc. – 2016 Performance-Based Regulation Capital Tracker True-Up (Decision 22672-D01-2018)
Performance-Based Regulation (PBR) – Capital Tracker True-up

In this decision, the AUC considered EPCOR Distribution & Transmission Inc.'s ("EPCOR") 2016 capital tracker true-up application.

Overview of PBR Capital Tracker Mechanism

The Performance Based Regulation ("PBR") framework, as described by the AUC, provides a formula mechanism for the annual adjustment of rates over a five-year term. In general, the companies' rates are adjusted annually by means of an indexing mechanism that tracks the rate of inflation ("I Factor") relevant to the prices of inputs less an offset ("X Factor") to reflect productivity improvements that the companies can be expected to achieve during the PBR plan period. The resultant I-X mechanism breaks the linkages of a utility's revenues and costs under a traditional cost-of-service model. The PBR framework allows a company to manage its business with the revenues provided for in the indexing mechanism and is intended to create efficiency incentives similar to those in competitive markets.

However, certain items may be adjusted for necessary capital expenditures ("K Factor"), flow through costs ("Y Factor"), or exogenous material events for which the company has no other reasonable cost control or recovery mechanism in its PBR plan ("Z Factor").

This supplemental funding mechanism was referred to in Decision 2012-237 as a "capital tracker" with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate setting formula.

Projects or programs are eligible for capital tracker treatment, provided that they meet the following three criteria:

(a) the project must be outside the normal course of on-going operations ("Criterion 1");

(b) ordinarily, the project must be for replacement of existing capital assets or the project must be required by an external party ("Criterion 2"); and

(c) the project must have a material effect on the company's finances ("Criterion 3").

Criterion 1: Project Assessment and Accounting Test

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 that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) 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.

Criterion 2

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.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company's finances, an applicant must satisfy the two-part Criterion 3 materiality threshold, namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

AUC Review Process for 2016 Capital Tracker True-up

In this decision, the AUC set out its approach for reviewing 2016 capital tracker true-up applications:

- For capital projects or programs not considered in prior capital tracker decisions, the AUC would assess all three criteria for capital tracker treatment.
- For projects or programs for which the need was previously confirmed under the project assessment component of Criterion 1, the AUC would not reassess the need in the absence of evidence that the project or program was no longer required. However, the AUC would assess the scope, level and timing of each project or program for prudence, and whether the actual costs of the project or program were prudently incurred, as required by the second part of the project assessment under Criterion 1.
- For programs or projects for which the AUC undertook and approved the assessment against the Criterion 2 requirements in prior capital tracker decisions, it would not reassess this unless the driver for the project or program had changed.
- The AUC would conduct an assessment of the 2016 capital tracker projects and programs with respect to the Accounting Test under Criterion 1 and materiality test under Criterion 3.

AUC Findings re EPCOR 2016 Capital Tracker True-up

The AUC determined that:

(a) EPCOR's proposed grouping of projects into programs was reasonable;

(b) the need for the capital tracker projects or programs included in the 2016 true-up had previously been confirmed in prior capital tracker decisions;

(c) the actual scope, level, timing and costs of each of the projects or programs included in the 2016 true-up were prudent, subject to the adjustments and directions by the Commission applicable to the Capitalized Underground System Damage, Life Cycle Replacement and Extension of Underground Distribution Cable and Life Cycle Replacement of Network Transformers projects or programs (the "AUC Adjustments and Directions");

(d) because of the AUC Adjustments and Directions, a reassessment of whether the capital tracker projects or programs satisfied the Accounting Test requirement of Criterion 1 was required;

(e) the previously approved capital tracker projects or programs included in the 2016 true-up continued to satisfy the requirements of Criterion 2; and

(f) because of the AUC Adjustments and Directions, a reassessment of whether the capital tracker projects or programs satisfied the two-tiered materiality test requirement of Criterion 3 was required.

Accordingly, the AUC directed EPCOR to revise its Accounting Test for 2016 in a compliance filing.

Capital Tracker Projects and K-Factor

The following table sets out:

(a) the capital tracker forecast amounts approved in Decision 21430-D01-2016 (2016 decision K factor);

(b) the projects and programs included in EPCOR's 2016 capital tracker true-up (2016 actual K factor); and

(c) the variance between the two, resulting in a proposed K factor true-up for 2016.

EPCOR's proposed amounts highlighted in yellow were subject to change as a result of the AUC's Adjustments and Directions, as summarized further below.

Program/Project name	2016 decision K factor	2016 actual K factor	Variance
	($ million)		
Third-Party Driven Relocations	3.45	2.96	(0.49)
Life Cycle Replacement and Extension of Underground Distribution Cable	2.31	2.65	0.34
New 15-kilovolt (kV) and 25-kV Circuit Additions	1.13	1.20	0.07
New Underground Cable and Aerial Line Reconfigurations and Extensions to Meet Customer Growth	1.33	1.20	(0.13)
Distribution Pole and Aerial Line Life Cycle Replacements	0.35	0.44	0.09
Aerial and Underground Distribution Transformers - New Services and Life Cycle Replacement	0.74	0.69	(0.05)
Capitalized Underground System Damage	0.73	0.98	0.25
New Underground and Aerial Service Connections for Commercial, Industrial, Multi-Family and Misc. Customers	1.79	2.13	0.34
Underground Residential Distribution (URD) Servicing - Rebates, Acceptance Inspections & Terminations	4.37	4.32	(0.05)
Capital Tools and Instrument Purchases	0.20	0.22	0.02
Poundmaker Feeders	0.44	0.40	(0.04)
OMS/DMS Life Cycle Replacement	1.45	1.63	0.18
Capitalized Aerial System Damage	0.24	0.18	(0.06)
Underground Industrial Distribution (UID) Servicing -	0.31	0.59	0.28

Rebates, Acceptance Inspections & Terminations			
Replacement of Faulted Distribution PILC Cables	0.30	0.30	0.00
Neighbourhood Renewal Program	0.28	0.05	(0.23)
Life Cycle Replacement of Network Transformers	0.38	0.41	0.03
Life Cycle Replacement of PILC Cable Systems	0.35	0.48	0.13
Customer Revenue Metering Program Customer Revenue Metering - Growth & Life Cycle Replacements Advanced Metering Infrastructure	1.03 2.13	1.02 3.96	(0.01) 1.83
IT Hardware Lifecycle Replacements and Additions	0.15	0.22	0.07
Vehicles – Growth and Life Cycle Replacements	0.00	0.19	0.19
2016 K factor total	24.01	27.25	3.24

Criterion 1: Project Assessment

For the projects/programs listed in the above table, with the exception of those highlighted, the AUC found that:

(a) with respect to the scope, level and timing of each, that capital additions were generally consistent with the scope, level and timing of the work outlined in the business cases for those capital trackers approved in Decision 20407-D01-2016; and

(b) the actual costs for associated procurement and construction practices and the evidence explaining the differences between approved forecast and actual costs, demonstrated such cost to have been prudently incurred.

However, because of the adjustments summarized below, the AUC found that it was unable to determine in this proceeding whether all of EPCOR's programs or projects included in the 2016 true-up satisfied the project assessment requirement of Criterion 1.

Adjustments and Directions

In the application, EPCOR noted that the Capitalized Underground System Damage Project costs included $0.26 million in closing 2016 construction work in progress that should have been recorded as capital additions in 2016. Accordingly, the AUC directed EPCOR, in the compliance filing to this decision, to add this amount to the Capitalized Underground System Damage Project 2016 capital additions.

In response to an AUC information request, EPCOR identified two other errors; specifically that replacement costs for 10 switching cubicles were recorded to the Capitalized Underground System Damage Project when they should have been recorded to the Life Cycle Replacement and Extension of Underground Distribution Cable Program, and costs in the amount of $0.23 million related to the capitalization of costs related to secondary cable faults were included in this project, which was inconsistent with the Commission's direction in Decision 20407-D01-2016. Accordingly, the AUC directed EPCOR, in the compliance filing, to remove the amounts related to these two errors from the Capitalized Underground System Damage Project 2016 capital additions, and to add the switching cubicle costs to the Life Cycle Replacement and Extension of Underground Distribution Cable Program 2016 capital additions.

In the application, EPCOR noted that the Life Cycle Replacement of Network Transformers Project costs erroneously included $0.10 million in costs related to the backbone fibre-optic communication system in its 2016 capital additions while it is an EPCOR transmission function asset. Accordingly, the AUC directed EPCOR, in the compliance filing, to remove this amount from the Life Cycle Replacement of Network Transformers Project 2016 capital additions.

Criterion 1: Accounting test

The AUC found that:

(a) EPCOR's application of the Criterion 1 Accounting Test analysis for the purposes of the 2016 capital tracker true-up was reasonable and generally consistent with the accounting test methodology approved in Decision 2013-435; and

(b) EPCOR used the correct values for WACC, I-X and Q factor assumptions used in the first component of the Accounting Test.

However, because of the adjustments summarized above, the AUC found that it was unable to determine in this proceeding whether all of EPCOR's programs or projects included in the 2016 true-up satisfied the Accounting Test requirement of Criterion 1.

Criterion 2: Ordinarily the project must be for replacement of existing capital assets or undertaking the project must be required by an external party

The AUC found that because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each project or program included in EPCOR's 2016 capital tracker true-up had not changed since approval of those proposed capital tracker projects/programs against the Criterion 2 requirements in Decision 3100-D01-2015 and in Decision 20407-D01-2016, there was no need to reassess those programs/projects against the Criterion 2 requirements.

Criterion 3 – The project must have a material effect on the company's finances

The AUC explained that, in accordance with its determinations in Decision 2013-435, the portion of the revenue requirement for a project or program proposed for capital tracker treatment that is not funded under the I-X mechanism in a PBR year, calculated as part of the accounting test, is then assessed against the two-tiered materiality test under Criterion 3. The first tier of the materiality threshold, a "four basis point threshold," is applied at a project level. The second tier of the materiality threshold, a "40 basis point threshold," is applied to the aggregate revenue requirement proposed to be recovered by way of all capital trackers.

The AUC found that EPCOR had generally interpreted and applied the Criterion 3 two-tiered materiality test properly for the purposes of its 2016 capital tracker true-up. However, the two-tiered materiality test under Criterion 3 is calculated as part of the Accounting Test. Given that AUC's earlier finding that EPCOR's accounting test for 2016 needed to be revised, the AUC found that it was unable to determine in this proceeding whether any of EPCOR's programs or projects included in the 2016 true-up satisfied the materiality test requirement of Criterion 3.

The AUC therefore directed EPCOR, in its compliance filing, to reassess whether its programs or projects included in the 2016 true-up satisfy the two-tiered materiality test requirement of Criterion 3.

FortisAlberta Inc. – 2016 Performance-Based Regulation Capital Tracker True-Up (Decision 22741-D01-2018)

Performance-Based Regulation (PBR) – Capital Tracker True-up

In this decision, the AUC considered FortisAlberta Inc.'s ("Fortis") 2016 capital tracker true-up application.

Projects or programs are eligible for capital tracker treatment, provided that they meet the following three criteria:

(a) The project must be outside the normal course of on-going operations ("Criterion 1");

(b) Ordinarily, the project must be for replacement of existing capital assets or the project must be required by an external party ("Criterion 2"); and

(c) The project must have a material effect on the company's finances ("Criterion 3").

Criterion 1: Project Assessment and Accounting Test

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 that:

(a) the project is required to provide utility service at adequate levels; and, if so,

(b) 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.

Criterion 2

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.

Criterion 3: Materiality Test

To assess whether a proposed capital tracker has a material effect on a company's finances, an applicant must satisfy the two-part Criterion 3 materiality threshold, namely, that:

(a) each individual project affects the revenue requirement by four basis points; and

(b) on an aggregate level, all proposed capital trackers must have a total impact on the revenue requirement of 40 basis points.

AUC Determinations

For the reasons further summarized below, the AUC made the following determinations:

(a) the AUC confirmed the need for the capital tracker programs or projects included in the 2016 true-up;

(b) the AUC found that the actual scope, level, timing and costs of each of the programs or projects included in the 2016 true-up were prudent, subject to the adjustments and directions by the Commission (the "AUC Adjustments and Directions") applicable to the Alberta Electric

System Operator ("AESO") Contributions Program; and

(c) the AUC found that the previously approved capital tracker projects or programs included in the 2016 true-up continued to meet the requirements of Criterion 2.

Because of the AUC Adjustments and Directions, the AUC found that it could not assess whether the programs or projects included in the 2016 true-up satisfied the accounting test requirement of Criterion 1 and materiality requirement under Criterion 3. Accordingly, the AUC directed Fortis to revise its Accounting Test in a compliance filing.

<u>Applied-for 2016 K factor true-up adjustments</u>

The following table sets out:

(a) the capital tracker forecast amounts approved in 21520-D01-2016 (2016 K factor);

(b) the projects and programs included in Fortis' 2016 capital tracker true-up (2016 actual K factor); and

(c) the variance, resulting in a proposed K factor true-up for 2016.

Program/project name	**2016 decision K factor**	**2016 actual K factor**	**Variance**
($ million)			
Customer Growth Program	26.5	21.2	(5.3)
AESO Contributions Program	15.9	13.1	(2.8)
Substation Associated Upgrades Program	6.1	4.5	(1.6)
Distribution Line Moves Program	3.2	3.0	(0.2)
Urgent Repairs Program, Worst Performing Feeders (WPF) Program, and Compliance, Safety, Aging Facilities, and Reliability Program (CSAR)	5.3	3.7	(1.6)
Distribution Capacity Increases Program	0.8	-	(0.8)
Pole Management Program	6.9	6.4	(0.5)
Cable Management Program	1.4	1.6	0.2
Distribution Control Centre (DCC) / Supervisory control and data acquisition (SCADA) Project	4.9	4.9	-
Load Settlement Replacement Project	-	1.6	1.6
2016 K factor total	70.9	60.1	(10.8)

<u>AESO Contributions Program</u>

The AUC explained that the AESO Contributions Program recognized the cost to Fortis of contributions paid to the AESO for the construction of AUC approved transmission facilities in Fortis' distribution area. The AUC originally approved the need for this program in Decision 2013-435 as part of the project assessment under Criterion 1.

2018-2022 PBR Plans Require Determination of Final Costs

The AUC set out the parameters for the next generation of 2018-2022 PBR plans for distribution utilities in Decision 20414-D01-2016 (Errata) (the "2018-2022 PBR Decision"). Amongst other things, the AUC determined in the 2018-2022 PBR Decision that:

- A K-bar mechanism would replace the capital tracker mechanism (K-factor). The K-bar is incentive-based, providing an amount of capital funding for each year of the 2018-2022 PBR term based on capital expenditures incurred in the previous PBR term.
- Under the K-bar mechanism, capital is to be divided into two categories: Type 1 and Type 2 capital:

  (i) Type 1 capital trackers, which replace the original capital tracker criteria established in

AUC Decision 2013-435 (K-Factor treatment criteria), require a project to be: (1) of a type that is extraordinary and not previously included in the distribution utility's rate base; and (2) required by a third party (the "Type 1 Project Criteria"); and

(ii) type 2 capital projects are all other capital additions that do not meet the Type 1 Project Criteria.

- For Type 2 capital additions, an initial K-bar capital factor ("$\bar{K}_0$") would be established as the incremental capital funding for all Type 2 capital in 2018. The base K-bar would be calculated by using an accounting test similar in concept to the test used during the 2013-2017 PBR term.

Given that the K-bar mechanism required finality of previously approved capital expenditure, in this case, the AUC found it was necessary to determine the point in time at which 2013-2017 capital tracker project costs should be considered final for the purposes of finalizing the rebasing revenue requirement and K-bar amounts.

Considering Final AESO Contributions Program Costs

The AUC rejected Fortis' proposal that contributions be deemed to be final each year and its related proposal that 2016 AESO contribution capital tracker be considered final upon the issuance of the AUC's decision respecting this application, based on the following findings:

(a) additional true-ups of AESO contributions associated with specific AESO projects might continue for several years after the first year in which Fortis records such expenditures;

(b) AESO contribution amounts necessarily change through time; and

(c) if the Commission were to accept Fortis' proposal to deem AESO contributions as final in each year, Fortis would enjoy a windfall gain, as it moved from the current capital-tracker-based PBR regime into the next generation PBR regime.

In recognition of the potential desirability to have a relatively short and "clean" transition of AESO contributions to the next generation PBR plan, the AUC wished to consider other proposals that would balance the interests of Fortis' shareholders and customers.

The AUC therefore directed Fortis to provide its view and potential recommendations on this matter as part of its compliance filing.

<u>AUC Findings re Criterion 1</u>

The AUC found that:

(a) Fortis methodology was reasonable and generally consistent with the Accounting Test; and

(b) Fortis used correct values with respect to WACC, I-X and Q factor assumptions.

However, because of the AUC Directions and Adjustments regarding the AESO Contributions Program, the AUC found that it could not make a determination in this proceeding as to whether all of Fortis' programs or projects included in the 2016 true-up satisfied the project assessment requirement of Criterion 1.

For the same reason, the AUC found that it could not determine whether all of Fortis' programs or projects included in the 2016 true-up satisfied the accounting test requirement of Criterion 1.

The AUC therefore directed Fortis, in its compliance filing, to revise its accounting test for 2016 and reassess whether the included capital tracker programs or projects satisfied the accounting test requirement of Criterion 1.

<u>AUC Findings re Criterion 2</u>

The AUC found that, because the driver or drivers (e.g., replacement of existing assets, external party, growth) for each of the projects included in Fortis' 2016 capital tracker true-up had not changed since the Commission originally approved those projects for capital tracker treatment, there was no need to reassess those programs or projects against the Criterion 2 requirements.

<u>AUC Findings re Criterion 3</u>

The AUC found that:

- Fortis interpreted and applied the Criterion 3 two-tiered materiality test properly for the purposes of its 2016 capital tracker true-up.
- However, because Fortis' accounting test for 2016 needed to be revised, the AUC could not determine in this proceeding whether any of Fortis' programs or projects included in the 2016 true-up satisfied the materiality test requirement of Criterion 3.

The AUC therefore directed Fortis, in its compliance filing, to reassess whether its programs or projects included in the 2016 true-up, satisfied the two-tiered materiality test requirement of Criterion 3.

Order

The AUC directed Fortis to file a compliance filing application in accordance with the AUC's directions contained in this decision.

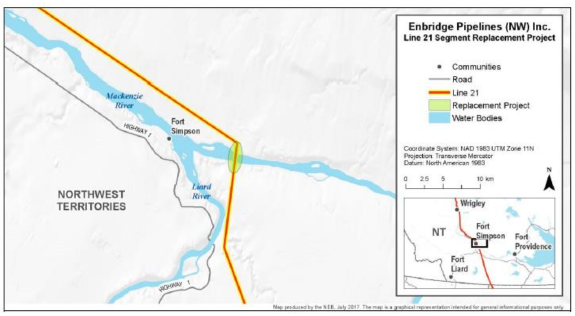
NATIONAL ENERGY BOARD

Enbridge Pipelines (NW) Inc. – Line 21 Segment Replacement Project Application (Decision MH-001-2017)
Pipeline Facility

Enbridge Pipelines (NW) Inc. ("Enbridge") applied to the NEB for an Order under Part III of the *National Energy Board Act* ("*NEB Act*") to build and operate up to 2.5 kilometres of new 323.9 mm (NPS 12) under the Mackenzie River (the "Application").

The figure below shows the location of the pipeline project (the "Project"):

Figure: Project Location Map



In the Application, Enbridge requested the NEB:

(a) Approve Enbridge's proposal to install the pipeline segment using a horizontal directional drilling ("HDD") trenchless crossing method; and

(b) Grant permission to leave the section of pipeline that was being replaced under the Mackenzie River.

Specifically, Enbridge requested that the Board grant the following relief:

(a) an Order pursuant to section 58 of the NEB Act, approving the construction and operation of the Project and exempting Enbridge from the provisions of paragraph 30(1)(b), subsections 31(c), 31(d) and section 33 of the *NEB Act*; and

(b) an Order pursuant to section 45.1 of the *National Energy Board Onshore Pipeline Regulations (*"OPR") to decommission the segment of the existing pipeline in state.

The NEB approved the Application, subject to conditions, based on the following findings:

(a) the general design of the Project was appropriate for its intended use and the Project would be constructed and operated in accordance with all applicable legislation and standards;

(b) Enbridge's approach to decommissioning was appropriate in the current circumstances, including its proposal to leave the existing Line 21 pipeline segment in place;

(c) with the implementation of Enbridge's environmental protection procedures and mitigation, as well as the Board's imposed conditions, the Project was not likely to cause significant adverse environmental effects;

(d) Enbridge's design and implementation of its Project-specific public and Indigenous engagement activities were appropriate for the scope and scale of the Project and all Indigenous peoples 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 Board; and

(e) The Project was economically feasibility.

The NEB concluded that the Project, inclusive of the terms and conditions set out in Order XO-E102-002-2018 and the conditions contained in Order MO-002-2018 was in the public interest.

Maritimes & Northeast Pipeline Management Ltd. – Application for Approval of MNLRS-IOL Service and Toll (Letter Decision RHW-001-2017)
Pipeline New Service and Toll – Load Retention Service

In this letter decision, the NEB considered Maritimes & Northeast Pipeline Management Ltd. ("M&NP") application for approval of a new load retention service and toll (the "Application").

In the Application, M&NP requested that the NEB approve a new load retention service (the "LRS") offering, including a new toll (the "LRS Toll").

The NEB found the LRS and LRS Toll Application to be a premature response that gave rise to significant concerns among affected parties.

The NEB denied the Application, but without making any determination as to whether the LRS Toll would be just and reasonable and not unjustly discriminatory under Part IV of the *NEB Act*.

<u>Proposed LRS and LRS Toll</u>

The proposed LRS and LRS Toll was for Irving Oil Commercial G.P. ("Irving Oil") for gas transmission service from the Canada-U.S. border to Irving Oil's

Refinery and cogeneration facility located in Saint John, New Brunswick. The LRS was negotiated between Irving Oil and M&NP and was intended to retain the Irving Oil load on the M&NP system. M&NP submitted that Irving Oil was considering alternative service for the Oil Refinery and Cogen load pursuant to a service offering from Emera Brunswick Pipeline Company Ltd. ("EBPC"), which the Board referred to as the "EBPC Alternative." M&NP stated that it offered Irving Oil the LRS in direct response to this competitive offer.

The NEB provided the following summary of the key terms and conditions of the LRS and LRS Toll:

- Firm service for a primary term of 13 years, estimated to commence on 1 December 2019.
- Contract quantity of 68,579 gigajoules per day (GJ/d).
- Primary receipt point at the M&NP interconnection with the M&NP U.S. system on the Canada-U.S. border at St. Stephen, New Brunswick and primary delivery point at the M&NP custody transfer station at the Irving Oil Refinery.
- LRS Toll of $0.2417 per GJ/d, only applicable at the designated primary receipt and delivery points.

<u>Legislative Scheme</u>

The NEB explained that Part IV of the *NEB Act* sets out the NEB's mandate in respect of traffic, tolls and tariff matters, including:

- Section 62 of the *NEB Act,* which provides that all tolls shall be just and reasonable and shall always, under substantially similar circumstances and conditions with respect to all traffic of the same description carried over the same route, be charged equally to all persons at the same rate.
- Section 67 of the *NEB Act,* which prohibits a company from making any unjust discrimination in tolls, service or facilities against any person or locality.
- Section 63 of the *NEB Act*, which provides that the NEB may determine as questions of fact whether or not traffic is or has been carried under substantially similar circumstances and conditions as referred to in section 62 or whether there is unjust discrimination within the meaning of section 67.

<u>NEB Reasons for Denying the Application</u>

Was the LRS required?

In assessing the Application, the NEB considered whether the LRS was required and whether the EBPC Alternative was well-founded. The NEB found that:

(a) the EBPC system had sufficient existing capacity to serve the Irving Oil load with small facility additions;

(b) the EBPC Alternative would provide comparable service quality as on M&NP; and

(c) Irving Oil would be expected to pursue the EBPC Alternative to meet its service needs if the Application were denied.

The NEB found that from this narrow perspective, the EBPC Alternative arguably represented a credible alternative to service of the Irving Oil load. The NEB agreed with M&NP that an alternative service option need not be fully mature to be considered a credible threat. However, the NEB did not accept M&NP's assertion that the necessary modifications to the EBPC system to accommodate the Irving Oil Load would require minimal Board regulatory review.

The NEB noted that as the hearing process and evidentiary record evolved, interveners raised significant broad concerns and uncertainties about the future of the natural gas market in the Maritimes and the impact on shippers, in particular, those captive to M&NP. The NEB noted such concerns raised, including current and future supply and markets of M&NP and EBPC; the respective roles of the two systems historically, currently and in the future; and the benefits and costs of inter-pipeline competition.

The NEB found that:

(a) Splitting the domestic market demand between the two pipelines post-2019 might challenge the viability of M&NP, which, as a result, could affect the Maritime natural gas market unfavourably;

(b) other load retention service applications to serve industrial loads in the Saint John raised further concerns about the long-term future of the natural gas market in the Maritimes and the potential impact of load retention services on M&NP's captive shippers; and

(c) in light of such broad concerns and uncertainties, not all parties with a potential interest in these broader matters – such as all potentially impacted local distribution companies, large industrial gas consumers, and pipelines in the Maritime natural gas market – participated or submitted evidence in this proceeding.

The NEB acknowledged that pipelines must adapt to changing conditions in their markets and that M&NP had proactively developed the LRS proposal to respond to the perceived competition from EBPC. However, the NEB found the LRS and LRS Toll Application to be a premature response that gave rise to significant concerns among affected parties.

Disposition

For the reasons set out above, the NEB denied the Application, but without making any determination as to whether the LRS Toll would be just and reasonable and not unjustly discriminatory under Part IV of the *NEB Act*.