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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 Vincent Light at Vincent.Light@RLChambers.ca.

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ALBERTA ENERGY REGULATOR

Release of the Integrated Compliance Assurance Framework and Manual 013: Compliance and Enforcement Program; Rescission of Directive 019: Compliance Assurance (Bulletin 2016-01)
Compliance Assurance – Enforcement – Bulletin

The AER released Bulletin 2016-01 announcing the harmonization of the AER's new compliance assurance requirements under "energy resource enactments" and "specified enactments" under the *Responsible Energy Development Act*. The following documents were released, effective immediately with Bulletin 2016-01:

- The *Integrated Compliance Assurance Framework* ("*ICAF*"); and
- *Manual 013: Compliance and Enforcement Program* ("Manual 013").

The AER described the key terms in the *ICAF* and Manual 013 as follows:

Key Items	Location in Manual 013
Compliance and Enforcement When considering how to respond to noncompliance, AER staff consider the factual circumstances of the noncompliance and the severity of its actual or potential impacts. The compliance history of the regulated party is taken into consideration, as well as how to achieve the best environmental, public safety, and operational outcomes.	Chapter 1
Voluntary Self-Disclosure Voluntary self-disclosure (VSD) is a regulated party's disclosure of a noncompliance that may qualify under the VSD process. When a regulated party identifies a noncompliance, the AER expects it to be corrected or addressed and reported to the AER in writing. The AER also expects the regulated party to act as if the AER had identified the noncompliance.	Chapter 3
Noncompliance Triage Assessment Tool The noncompliance triage assessment is a tool that helps to ensure a consistent approach to responding to noncompliance. AER staff are to use it when considering the context and specifics of individual cases of noncompliance.	Chapters 4 & 5
Investigation Process The goal of an investigation is to systematically collect information to verify that a noncompliance has occurred, identify its cause, and determine whether an enforcement response action is required.	Chapters 5 & 6
Notice of Noncompliance A notice of noncompliance notifies a regulated party in writing that it is in noncompliance with a specific regulatory requirement and often recommends a course of action that is expected to achieve compliance.	Chapter 7

Of note, the AER rescinded Directive 019: Compliance Assurance effective immediately, which is replaced with Manual 013. The AER noted that it plans to make consequential amendments to its directives, manuals, orders, approvals and other documents to update references to "Directive 019" to refer to "Manual 013".

A copy of the *ICAF* can be found here. A copy of Manual 013 can be found here.

ALBERTA UTILITIES COMMISSION

Finlay Group Complaint Regarding FortisAlberta Inc. Distribution Line Rebuild Project (Decision 20799-D01-2016)

Complaint – Distribution Facilities

A group of landowners located near a distribution line in the Red Deer area (the "Finlay Group") lodged a complaint with the AUC in respect of a proposed rebuild of the 25-kilovolt distribution line designated as Line 262, operated by FortisAlberta Inc. ("Fortis").

The Finlay Group expressed concerns regarding visual impacts and environmental degradation caused by the rebuild of the distribution line, and questioned whether Fortis adequately considered routing alternatives.

Fortis submitted that the proposed rebuild was slated for construction along its existing alignment, due primarily to load growth and customer commitments for new load in the Red Deer area. Fortis submitted that the construction method proposed was a "lean and rebuild" referring to a method by which the existing power line is excavated and leaned to allow a new power line to be set and strung in the same alignment. Fortis noted that the old line would lean toward property, and not the road, since leaning toward the road would reduce vertical clearance for traffic, which may raise safety concerns. Fortis submitted that the lean and rebuild method yielded the following advantages:

- System integrity remained intact during new construction, and customers are not affected by power interruptions;
- New construction can proceed outside of 'minimum approach distances' required by the *Alberta Electric Utility Code*; and
- The lean and rebuild method requires very little specialized equipment.

However, Fortis noted that in order to maintain safe clearance heights, that vegetation and some existing structures would need to be removed in order to safely lean the line.

The Finlay Group submitted its concerns with the removal of trees within the municipal reserve, since the line would be leaned onto the municipal reserve lands. The Finlay Group suggested two alternative methods for the rebuild:

- Leaning the existing power line towards the road, which would create outages for customers along the affected road and may require closing a portion of the road, but would not require the removal of any trees; or
- Using a sectional live-line approach along the road.

The Finlay Group noted that in an effort to save the trees, each of the customers along the section of the rebuild would accept power outages required for a live-line construction method.

Fortis replied that the alternative methods would negatively impact the safety, reliability and cost of the project. Fortis also stated that it examined providing separate generation to each resident during construction, but noted that the extra time and expense necessary was prohibitive.

The Finlay Group also proposed an alternative route for construction. Fortis originally proposed a double-circuit distribution line along the existing route of the single-circuit line. The Finlay Group proposed instead building an additional circuit along Township Road 380, located nearby, eliminating the need for a double-circuit distribution line, and improving system reliability.

Fortis replied that the single-circuit proposal would add one kilometer of length to the distribution line and would traverse wetlands, a railway crossing and a highway crossing. Fortis submitted that this alternative was more costly and did not consider it viable.

The AUC held that the scheme for the construction and operation of distribution lines was inherently different from those of transmission lines. Notably, under the *Hydro and Electric Energy Act*, AUC approval is required for new or amended transmission lines. However, due to the extensive nature of distribution lines, the AUC does not issue approvals for new or amended lines. Instead, the AUC held, it assigns and approves distribution areas to distribution service providers, which empowers each provider to determine where facilities are required.

Aside from resolutions of complaints or disputes, the AUC noted that it has no direct oversight or approval role for distribution lines. Therefore, the AUC considered that its role in deciding the complaint was to determine whether Fortis exercised its statutory duties under the *Electric Utilities Act* to maintain a safe, reliable, economic and efficient electric distribution system.

The AUC determined that the Finlay Group proposals to lean the power line toward the road or use a live-line method were inferior to the Fortis proposal on grounds of safety and economics. Accordingly, the AUC held that it was satisfied that none of the alternatives proposed by the Finlay Group were superior to Fortis' plan to rebuild the line.

However, the AUC encouraged Fortis to work with the Finlay Group to mitigate the impact of the project on trees in the municipal reserve area.

As a result of the above findings, the AUC dismissed the complaint by the Finlay Group, and stated that Fortis may proceed with the distribution line rebuild as planned.

EPCOR Distribution & Transmission Inc. 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast (204087-D01-2016)
Capital Tracker – True-Up – Rates

ECPOR Distribution & Transmission Inc. ("EDTI") applied for approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance-based regulation ("PBR"). EDTI requested that the revenue requirement associated with the applied-for capital trackers be included in the applicable year.

The 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 in 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 material exogenous 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:

- The project must be outside the normal course of on-going operations ("Criterion 1");
- 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
- The project must have a material effect on the company's finances ("Criterion 3").

In order to qualify under Criterion 1, the AUC noted that the increase in associated revenue provided by the PBR formula must be insufficient to recover the entire revenue requirement associated with the prudent capital expenditures for the program or project in question. This test is therefore considered by the AUC as more accounting oriented than engineering oriented, although such applications must generally be supported by an engineering study and business case to assess the reasonableness of the request.

With respect to Criterion 2, generally a growth related project which can demonstrate that customer contributions and incremental revenues are insufficient to offset the revenue requirements associated with a project for a given PBR year will satisfy the requirements.

The materiality threshold in Criterion 3 requires that each project must individually 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.

EDTI applied for capital tracker treatment for the following amounts:

- A reduction of $2.21 million for its 2014 K factor true-up;
- 2016 K factor amounts of 27.57 million, consisting of 24.52 million for previously approved projects, and 3.05 million for projects not previously approved.
- 2017 K factor amounts of 38.16 million, consisting of 28.65 million for previously approved projects, and 9.49 million for projects not previously approved.

EDTI applied for capital tracker treatment for the following projects and programs, in the following amounts:

($ million)	2014 variance	2016 forecast	2017 forecast
Third party Driven Relocations	(0.82)	3.40	4.09
Life Cycle Replacement and Extension of Underground Distribution	(0.29)	2.40	3.36

New 15- and 25-kV Circuit Additions	(0.06)	1.11	1.71
New Underground Cable and Aerial Line Configurations and Extensions to Meet Customer Growth	(0.29)	1.30	1.72
Distribution Pole and Aerial Line Life Cycle Replacements		0.33	0.54
Aerial and Underground Distribution Transformers – New Services and Life Cycle Replacement	(0.11)	0.71	1.00
Capitalized Underground System Damage	(0.11)	0.71	0.94
Vehicles – Growth and Life Cycle Replacements		-	-
New Underground and Aerial Service Connections for Commercial, Industrial, Multi-family and Misc. Customers	(0.16)	1.77	2.50
Underground Residential Distribution (URD) Servicing – Rebates, Acceptance Inspections & Terminations	(0.30)	4.30	5.51
Capital Tools and Instrument Purchases		0.19	0.22
Poundmaker Feeders	(0.04)	0.44	0.40
OMS/DMS Life Cycle Replacement		1.44	1.79
Capitalized Aerial System Damage	(0.03)	0.23	0.32
Underground Industrial Distribution (UID) Servicing – Rebates, Acceptance Inspections & Terminations	(0.03)	0.30	0.44
Replacement of Faulted Distribution PILC Cables	0.12	0.30	0.39
Neighbourhood Renewal Program	(0.01)	0.28	0.24
Customer Revenue Metering – Growth & Life Cycle Replacements	(0.02)	4.60	2.30
Life Cycle Replacement of Network Transformers		0.37	0.54
Life Cycle Replacement of PILC Cable Systems		0.34	0.54
Previously Approved Projects (subtotal)	**(2.21)**	**24.52**	**28.65**
Advanced Metering Infrastructure		2.12	5.89
Work Centre Redevelopment		0.59	2.49
IT Hardware Lifecycle Replacements and Additions		0.15	0.27
Rebuild and/or Replace Civil Work for Downtown Vualts and Manholes		0.19	0.27
Switching Cubicle Life Cycle Replacement		-	0.13
Network Reconfigurations		-	0.32
Street Light Service Connections and Security Lighting Addition and Capital Replacement		-	0.12
Not Previously Approved Projects (subtotal)	**-**	**3.05**	**9.49**
Total	**(2.21)**	**27.57**	**38.16**

In total, EDTI applied for capital tracker treatment of 27 separate capital projects or programs in the years 2016 and 2017, 20 of which were previously approved by the AUC in Decision 2013-435 or Decision 3100-D01-2015.

Project Grouping

EDTI submitted that it applied the same approach to grouping as it did in prior capital tracker applications, which was approved in Decision 2013-436 and Decision 3100-D01-2015 with certain exceptions.

The AUC noted that in Decision 3100-D01-2015, it found EDTI's general approach to grouping as reasonable, but questioned whether all of EDTI's life cycle replacement projects should be grouped together with the Neighbourhood Renewal Program for the purposes of the accounting test under Criterion 1. The AUC noted that all of these projects and programs had the key aim of replacing or renewing aging assets.

EDTI explained in this application that while such a grouping was "technically possible", it submitted that it would be impractical and very burdensome to complete.

Neither the Utilities Consumer Advocate ("UCA") nor the Consumers' Coalition of Alberta ("CCA") took issue with EDTI's proposed project groupings.

The AUC held that EDTI adequately responded to its directions from Decision 3100-D01-2015 in respect of grouping life cycle replacement programs with the Neighbourhood Renewal Program. The AUC held that, to the extent the project groupings for previously approved projects were the same as found in Decision 3100-D01-2015, it considered these groupings to be reasonable, and approved them as filed.

Grouping of New Capital Tracker Projects

EDTI submitted that it will be installing new Advanced Metering Infrastructure ("AMI") meters during 2016 and 2017, stating that it planned to replace customer meters with AMI meters, and that a number of meters are in need of replacement. EDTI stated that it would group AMI costs with growth and life cycle replacement projects, but would maintain tracking as a separate line item.

The AUC held that grouping AMI projects with other growth and life cycle replacement projects would have no effect on the total K factor over the forecast period, as both were net positive throughout 2016 and 2017. However, the AUC directed that EDTI group these projects together under the title "Customer Revenue Metering", while filing separate business cases for both.

EDTI also applied for a Work Centre Redevelopment project, which consisted of acquiring a new building and space at its north service centre, and redeveloping the north service centre and south service centre, along with consolidating EDTI employees at other locations to the north and south service centres, and transferring EDTI's training facilities to its Winterburn location. EDTI did not group the life cycle replacements for the north and south service centres with this project, submitting that the life cycle replacements were mainly repairs and capital maintenance.

The CCA opposed EDTI's grouping on the basis that EDTI was only able to distinguish these projects based on scope and scale, rather than separate drivers for the projects themselves.

The AUC held that while there were differences in timing and scope for the Work Centre Redevelopment and other building life cycle replacements, the projects were not sufficiently different to warrant separate groupings for capital tracker purposes. The AUC therefore directed EDTI to group the Work Centre Redevelopment project along with the other building life cycle replacement projects into a single grouping for its compliance filing.

EDTI submitted that its Civil Work for Downtown Vault and Manholes included repairing and replacing deteriorated vault or manhole structures in its network.

Neither the UCA nor the CCA raised any concerns with the Civil Work for Downtown Vault and Manholes project.

The AUC held that the Civil Work for Downtown Vault and Manholes Project was substantially similar in terms of scope and drivers to the Distribution Manhole Rebuilds (for which capital tracker treatment was not requested). The AUC therefore directed that EDTI group these projects together in its compliance filing.

Criterion 1 Assessment

EDTI submitted that it applied the following inflation factors for its 2016 and 2017 forecast costs:

- 4.0 percent salary escalation factor for non-union staff;
- 3.0 percent escalation for union staff;
- Employee fringe benefit rates of 43.65 percent to all salary and labour costs;
- Material cost inflators of 2.2. percent; and
- Contractor cost inflators of 3.1 percent and 3.2 percent for 2016 and 2017 respectively.

EDTI explained that it did not forecast costs related to specific capital cost categories for 2016 and 2017, since it is under PBR. EDTI instead applied a capital overhead amount to the cost of the projects using a capital overhead rate of 8.0 percent. The CCA argued that EDTI's forecast allocated overhead costs, for which EDTI claimed a 3.4 percent increase, should be reduced to the 2016 I factor of 2.06 percent. EDTI however, argued that the application of the I factor to the overhead cost of each capital project was not relevant to the calculation of overhead costs.

EDTI requested the inclusion of its short term incentive pay ("STIP") costs associated with staff that work on capital projects. EDTI submitted that it historically did not capitalize its STIP costs, but were instead allocated to the master overhead pool for operating cost categories. However, EDTI stated that the change is consistent with the remainder of the EPCOR corporate group, and that the costs should be capitalized as they are directly attributable to capital expenditures.

The CCA recommended that the AUC reject the inclusion of STIP costs for two reasons. First, that incentive pay costs were already included in EDTI's going-in rates for PBR, and so may be double counted. Second, EDTI was not proposing any changes to its I-X portion of rates as a result of its STIP calculation.

The AUC held, with respect to STIP costs, that EDTI was required to disclose the change in accounting methods as part of its attestation letter for the present application. However, the AUC found that because the capitalization policy for STIP had not been implemented until late 2014, EDTI could not have included this information in its application, which was filed on September 10, 2014.

The AUC also accepted the CCA's argument regarding STIP costs. The AUC found that double counting would occur if STIP costs are capitalized under capital tracker programs, since the I-X component of PBR rates already provide funding to account for those costs. The AUC therefore directed EDTI to remove any STIP costs from its compliance filing.

The AUC held that the evidence before it did not support a 4.0 percent salary increase for non-union labour, pointing to the evidence presented by EDTI that such labour escalators are trending downward. The AUC accordingly approved a non-union escalation rate of 3.0 percent for the 2016 and 2017 period, and directed EDTI to reflect these findings in its compliance filing.

The AUC held that it was not persuaded that EDTI's increases in capital overhead amounts were reasonable. Therefore, in the absence of evidence supporting such a requested increase, the AUC held that it would not approve overhead costs in excess of an amount adjusted by the I-X mechanism for the applicable year. The AUC approved the remainder of EDTI's input escalation rates as filed, finding them to be reasonable.

EDTI submitted that its Customer Revenue Metering – Growth & Life Cycle Replacements project was outside the normal course of business, owing to impacts in changes to Measurement Canada's meter testing requirements. EDTI also submitted that its Customer Revenue Metering – Growth & Life Cycle Replacements project was approved for capital tracker treatment in Decision 3100-D01-2015. EDTI submitted that all new meters installed would be AMI meters, which were obtained through a competitive bidding process.

The AUC held that the Customer Revenue Metering – Growth & Life Cycle Replacements project scope, level and timing of costs were reasonable. EDTI submitted that its Customer Revenue Metering – Growth & Life Cycle Replacements project was outside the normal course of business, owing to impacts in change to Measurement Canada's meter testing requirements. EDTI also submitted that its Customer Revenue Metering – Growth & Life Cycle Replacements project was approved for capital tracker treatment in Decision 3100-D01-2015. EDTI submitted that its 2014 actual costs for its AMI project, which formed part of the Customer Revenue Metering – Growth & Life Cycle Replacements project, were impacted by new requirements from Measurement Canada to test, and in some cases replace, existing meters on its system. EDTI noted that it was in the process of applying for a temporary dispensation from Measurement Canada to test its recently installed AMI meters. EDTI submitted that all new meters installed would be AMI meters, which were obtained through a competitive bidding process.

The AUC therefore directed EDTI to explain the impacts on its 2014 actual costs in its compliance filing. The AUC otherwise held the scope, level and timing of the Customer Revenue Metering – Growth & Life Cycle Replacements project to be reasonable for 2016 and 2017.

EDTI also requested accelerated depreciation expenses for the Customer Revenue Metering – Growth & Life Cycle Replacements project. The AUC held that allowing a company to file a depreciation study, or a depreciation technical update was inconsistent with the third PBR principle, namely that the PBR plan should be easy to understand, implement and administer. The AUC held that the introduction of a depreciation technical update, with the exception where a Z factor (a material exogenous event for which the company has no other cost recovery mechanism available) adjustment is warranted. The AUC denied the technical update for depreciation rates on the basis that such adjustments would not comport with the object of PBR to reduce the regulatory burden, and provide an established revenue framework during the PBR period. The AUC directed EDTI to remove the accelerated depreciation amounts from the K factor calculation in its compliance filing.

The AUC held that each of the remaining capital tracker projects and programs met the requirements for Criterion 1 and accordingly approved the need, scope, level and timing for each program, either on an actual basis for 2014, or on a forecast basis for 2016 and 2017.

However, since the AUC directed changes to EDTI's accounting test as it relates to the approved I-X index value and Q factor values for 2016, the AUC held that it was unable to make a determination as to whether the capital tracker projects met the accounting test under Criterion 1 in its entirety.

The AUC therefore directed EDTI to revise its accounting test in its compliance filing to reflect the approved I-X index value and Q factor values for 2016 and 2017.

<u>Criterion 2 Assessment</u>

EDTI confirmed that the drivers for each of its previously approved programs and projects have not changed, and that its programs and projects were each approved in Decision 3220-D01-2015 as having met the requirements of Criterion 2.

The AUC held that there was no need to undertake a reassessment of any of the projects or programs against the Criterion 2 requirements.

For the new capital tracker projects and programs, EDTI submitted that each met the requirements for Criterion 2. EDTI explained that although its AMI project was not required due to system growth or increase in load, it involved the replacement of existing capital assets.

The UCA submitted that the AMI project did not meet the requirements of Criterion 2, since it was not required for the replacement of aged infrastructure that has come to the end of its useful life, nor was it required by a third party.

The AUC held that although the conventional customer meters were capable of continuing to provide their respective metering functions, the least cost alternative for EDTI was to replace the assets with AMI meters. Accordingly, the AUC held that the AMI project was a replacement of existing infrastructure and met the requirements of Criterion 2.

The AUC held that all other new capital tracker projects and programs complied with the requirements of Criterion 2.

<u>Criterion 3 Assessment</u>

Criterion 3 is a two step materiality test which assesses the impact of capital tracker costs at four basis points of total revenue requirement for individual projects or programs, and 40 basis points of total revenue requirement for the total capital tracker costs not covered by the I-X mechanism for the applicable year.

For its 2014 capital tracker true-up, EDTI applied a four basis point threshold of $103,327 and a 40 basis point threshold of $1.033 million, which it submitted were previously approved in Decision 3100-D01-2015. EDTI also submitted that each 2014 capital tracker project or program satisfied both materiality requirements of Criterion 3.

For 2016-2017, EDTI submitted that it calculated the materiality thresholds consistent with the methodology set out in Decision 2013-435. However, since EDTI did not have approved inflation factors for 2016 or 2017, it used I-X index values of 0.42 percent for 2016 and negative 0.21 percent 2017 based on the approved X factor, and its own inflation forecasts. Accordingly, EDTI calculated its 2016 materiality thresholds as follows:

- Four basis point threshold: $105,307; and
- 40 basis point threshold: $1.053 million.

EDTI calculated its 2017 materiality thresholds as follows:

- Four basis point threshold: $105,086; and
- 40 basis point threshold: $1.051 million.

None of the interveners took issue with the 2014, 2016 or 2017 materiality thresholds.

The AUC held that EDTI's calculations and forecasting methods were reasonable. The AUC accordingly approved FAI's 2014 threshold values as filed, and confirmed that the 2014 true-up values met the materiality thresholds of Criterion 3 for capital tracker treatment. However, since the filing of EDTI's application, the AUC provided a final 2016 I-X value of 0.90 percent in Decision 20821-D01-2015. Therefore, the AUC directed FAI, in its compliance filing, to apply materiality thresholds for Criterion 3 using the approved 2016 I-X factor as a forecast value for both 2016 and 2017.

<u>2014 True-Up and 2016-2017 K Factor Calculations</u>

EDTI proposed to use its Rider DJ to collect or refund any approved 2014 K factor adjustment.

EDTI submitted that its final base rates and billing determinants are applied for as part of its annual PBR rate adjustment filings. EDTI would therefore provide calculations of its 2016 capital tracker allocator percentages and adjustments to rates with its 2016 annual PBR adjustment filing for 2016, and the subsequent 2017 values as part of its 2017 PBR adjustment filing for 2017.

The AUC held that while it confirmed the prudence of the actual capital additions associated with EDTI's projects and programs for 2014, due to the removal of the STIP amounts and other revisions, the AUC could not approve a final 2014 K factor true up adjustment.

Similarly, the AUC held that EDTI's forecast capital expenditures for 2016-2017 were generally reasonable, subject to the removal of the STIP amounts. However, due to the AUC's directions for EDTI to change its materiality test under Criterion 3, and to change the accounting test under Criterion 1, it could not approve the 2016 or 2017 K factor adjustments in this decision.

<u>Order</u>

The AUC directed EDTI to file a compliance filing in accordance with the directions in this decision on or before March 16, 2016.

TransAlta MidAmerican Partnership Sundance 7 Power Plant Time Extension (Decision 21062-D01-2016)

Time Extension – Facilities

TransAlta MidAmerican Partnership ("TAMA Power") filed an application with the AUC for approval of a time extension on its 856-megawatt Sundance 7 power plant, approved by Decision 3183-D01-2015. TAMA Power sought to extend the time for completion of Sundance 7 to December 31, 2022. TAMA Power's reasoning for the request was due to what it described as "the current regulatory uncertainty and economic volatility in Alberta."

TAMA Power also requested an extension of the requirement to submit progress reports every 3 months to every 6 months, until such time as construction begins. Upon commencement of construction, TAMA Power submitted that it planned on filing progress reports every 3 months.

The AUC held that TAMA Power provided information on the need, nature and duration of the time extension as being minor in nature. The AUC also held that the requested change to reporting intervals for pre-construction activities was reasonable, and granted TAMA Power's request.

EPCOR Energy Alberta GP Inc. 2014-2018 Energy Price Setting Plan Compliance Filing (Decision 20342-D02-2016)
Compliance Filing – Energy Price Setting Plan

EPCOR Energy Alberta GP Inc. ("EEA") filed a compliance filing for its energy price setting plan ("EPSP") in response to directions made by the AUC in Decision 2941-D01-2015.

Adjustment of after tax return margin

In Decision 2941-D01-2015 the AUC approved an all-in after-tax return margin of $2.51/megawatt-hour (MWh) for EEA. In this proceeding, EEA proposed to collect the $2.51/MWh charge as part of its energy rates effective March 1, 2016.

However, the AUC had previously approved a recovery of $1.99/MWh in the energy charge as a transitional measure as part of its findings in Decision 20342-D01-2015, with the balance being recovered through non-energy charges. The AUC later approved EEA's 2016 non-energy charges in Decision 20676-D01-2015, which did not include an amount for its all-in after tax return, leaving a $0.52/MWh amount to be trued-up.

As part of its application, EEA proposed to true up the collection of these amounts in its application for the months of January and February 2016.

The Utilities Consumer Advocate ("UCA") and Consumers' Coalition of Alberta ("CCA") expressed concerns only with respect to the true-up portion of the application, noting that section 3(2) of the *Regulated Rate Option Regulation* prohibits the use of true-ups, rate riders or other similar accounts or devices for energy-related costs.

Accordingly, the AUC did not accept EEA's proposal to true up the remaining $0.52/MWh charge, finding that it would violate section 3(2) of the *Regulated Rate Option Regulation*.

The AUC noted however that EEA may apply for the recovery of the true-up charges at the time EEA trues up its 2016 interim rates for its non-energy charge.

Adjustments to auction parameters

In Decision 2941-D01-2015, the AUC directed EEA to exclude any reference to a role for the Market Surveillance Administrator ("MSA") in its EPSP. EEA submitted that its auction parameters now no longer refer to the MSA. EEA noted that it procures its energy through an auction process on the Natural Gas Exchange ("NGX"). As part of its application, EEA requested the ability to adjust its approved parameters in order to maintain competitiveness in the marketplace. EEA noted three options to address the need for flexibility to adjust its approved auction parameters:

- Require EEA to seek AUC approval through a confidential and expedited process;
- Deny EEA the ability to implement any adjustments to its auction parameters; or
- Confirm EEA's understanding that it can make adjustments to its auction parameters, and file the adjustments with the AUC for acknowledgement.

The CCA argued that such unilateral discretion for EEA in the absence of any real oversight may lead to sub-optimal results for customer rates. The CCA submitted that EEA was instead required to demonstrate how any proposed adjustments actually resulted in EEA remaining competitive or becoming more competitive as a result.

The UCA, in contrast, acknowledged that an approved EPSP framework may require a number of amendments throughout its term to ensure that it continues to function effectively. However, the UCA voiced its concerns that EEA would be able to influence the base energy charge ("BEC") by manipulating the auction parameters. The UCA therefore argued that if auction parameter amendments were required, that EEA should apply to the AUC for approval of such amendments.

EEA submitted that it performs a thorough analysis prior to making any adjustments to its auction parameters, however, once the change is deemed necessary, EEA submitted that the change must be implemented quickly to mitigate any adverse effects caused by changing market conditions. EEA also submitted that its proposed level of discretion was limited, being restricted to small modifications that do not change the underlying nature of the auction process.

The AUC held that EEA complied with the direction to remove the references to the MSA in its EPSP.

With respect to the proposed modifications, the AUC held that it did not give specific direction on the adjustment of other parameters. The AUC agreed with EEA that a certain level of discretion was necessary to account for and respond to market developments that may materially affect the competitiveness of EEA's energy acquisition process for RRO customers. The AUC therefore held that the ex-post facto monitoring of rates relative to past raes, NGX market information and rates of other RRO providers were sufficient to determine whether the rates were just and reasonable. The AUC also directed EEA to file an acknowledgment letter with the AUC for any change in the auction parameters including the following information:

- An explanation of the market factors necessitating the change;
- A supporting analysis; and
- A schedule identifying the history of all changes to the individual parameters.

<u>Hedging</u>

In Decision 2941-D01-2015, the AUC directed EEA to set their final hedge targets at a level similar to the 75th percentile of the average hourly load during peak hours, and to produce an analysis demonstrating the effects on the BEC.

EEA submitted an analysis that reflected a hedging target based on the 60th percentile of the average hourly load during peak hours as having the lowest RRO energy charge, and submitted other information on a confidential basis.

The AUC approved EEA's application to hedge peak product to the 60th percentile, although its reasons for doing so were confidential.

<u>Backstop Mechanism</u>

The AUC directed EEA in Decision 2941-D01-2015 to include a backstop mechanism in its EPSP.

EEA provided a backstop mechanism that excluded a retainer fee with its backstop supplier. EEA's proposed backstop mechanism is a contract for supply to be executed following a request for proposal, and provided further information on a confidential basis.

The CCA submitted that the entire process in selecting a backstop supplier should be filed with the AUC on a monthly basis, and be fully transparent. The CCA also submitted that a formal backstop arrangement with a third party was not truly critical to procure its forecast hedges. Instead the CCA recommended that EEA should procure its backstop requirements through the over-the-counter market or the NGX screen.

The AUC echoed its concerns raised in Decision 2941-D01-2015 that EEA could not include an estimated cost of its proposed backstop arrangement. Accordingly, the AUC held that EEA did not provide sufficient information for the AUC to assess the cost of backstop procurement and therefore denied EEA's proposed backstop mechanism.

The AUC directed EEA to file an application to give effect to a new backstop supply mechanism. In the meantime, the AUC directed EEA to continue to maintain its current backstop mechanism.

<u>Commodity Risk Compensation Structure</u>

EEA submitted that, as part of its revised commodity risk compensation strategy, that it would transition its peak volume hedging from the 75th percentile to the 60th percentile. EEA explained that it would also calculate its variable risk compensation using the gains and losses for the preceding 12 months for which monthly settlements are available to determine the commodity risk compensation.

The AUC held that while EEA complied with the direction to revise its commodity risk compensation structure in Decision 2941-D01-2015, the AUC held that the calculation method using the prior 12 month period required "synthetic data", since 60th percentile hedging values were not available. As such, the AUC found that the commodity risk compensation structure was inconsistent with the direction provided in Decision 2941-D01-2015. Accordingly, the AUC directed EEA to revise its commodity risk compensation structure using actual historical commodity revenue for the prior 12 month period.

<u>Implementation</u>

EEA stated that after the AUC renders its decision on the EPSP compliance application, it would require five months to implement the EPSP. EEA offered the following reasons for its requested implementation period:

- EEA required four months' time to begin procuring under its new hedging percentile;

- EEA needed time to inform all potential block product suppliers of the changes, and needed to provide one month's notice prior to the first NGX auction using the new auction mechanism; and

- The reduced number of auctions required an elongated transition period, otherwise procurement would be skewed toward the beginning of the 120-day price setting period at the outset of the EPSP term.

The CCA submitted that EEA's proposal requesting five months was excessive, and recommended a one month transition period as of the date of the AUC's decision. The CCA submitted that there was no reason to believe that EEA's suppliers were not aware of the impending change, and that the extended notification period was not warranted. The UCA also supported a timely implementation of EEA's EPSP.

The AUC accepted EEA's argument that the change to its hedging strategy was the driver behind its implementation schedule, and found that such a quick change might cause a disproportionate amount of hedging volume to occur in the months prior to the transition. The AUC therefore held that one month for notice, and 120 days for procurement would result in a five month transition period, which it approved.

<u>Regulated Rates and Forecast Accuracy</u>

EEA stated that it would provide an illustrative forecast performance report showing the forecast variances due to weater, site counts and consumption levels on a monthly basis.

The CCA recommended that EEA should continue to provide peak data in the load forecast summary, as a reasonableness check for consumers. The CCA noted its concerns that EEA did not compare forecast peak percentage with the subsequent actual peak percentage. As a result, CCA recommended that the AUC order EEA to include the following in its monthly filings:

- the basis for determining the range of reasonableness in respect of the peak to base ratio, including historical data;

- the difference between forecast and actual peak to base ratio for the most recent month available;

- an assessment of the effect on rates as a result of the difference between forecast and actual peak to base percentages; and

- a description of any actions necessary for subsequent months.

The CCA also proposed, in the alternative, that the AUC undertake an audit using a list of specified parameters agreed to by EEA and consumer groups at regular intervals, in lieu of monthly filings.

EEA submitted that there was no evidence on the record of the proceeding that the additional information or process requested by the CCA would improve the operation of EEA's EPSP. EEA also submitted that the AUC previously held in Decision 2941-D01-2015 that the involvement of third parties in monthly filings was not needed, and that there was no evidence of negative consequences from their not participating in the monthly filing process.

The AUC held that the differences in views between the parties for monthly filings related only to the detail required to check the accuracy of the calculations and the scope of information to be provided. However, the AUC determined that the requests of the interveners were beyond what was required to review the ongoing operation of EEA's EPSP. Consequently, the AUC found that the monthly filings as proposed by EEA were sufficient to support the AUC's information requirements for monthly filings.

<u>Process for review of monthly filings</u>

The CCA requested a clarification on the timelines for reviewing monthly RRO filings, including access to confidential information. Given that the monthly rates are filed five days prior to the end of the month, the CCA recommended a process timeline for submitting clarification questions to EEA, as well as responses on a confidential basis.

EEA submitted that the timelines for filing are set by regulation, and argued that the CCA's proposal for the monthly filing process was reasonable or compatible with the *Regulation Rate Option Regulation*.

The AUC held that no further guidance was necessary on the process for monthly filings. However, the AUC noted it could establish further process if it considered it warranted based on an objection through the process already provided for in acknowledgement letters.

Forecasting Methodology

The UCA submitted evidence that EEA could manipulate the inputs to its load forecasts to achieve a desired expected volumetric position, equivalent to hedging beyond its approved target of the 60th percentile. The CCA raised concerns with the potential for manipulating forecasts toward the end of the EPSP term, on account of the 12 month lag in the risk cycle adder component of its EPSP.

EEA submitted that the forecast methodology was tested and approved by the AUC in Decision 2941-D01-2015. EEA also submitted that the forecast methodology itself was a purely mechanical exercise with no decision points or ability to manipulate forecasting techniques. EEA submitted that the only tool it has to manage forecasting risk is the accuracy of its forecasting.

The AUC dismissed the CCA's concerns with forecast manipulation, noting that EEA's forecast methodology was tested and approved, and in any event, contained no decision points.

Conclusion

The AUC approved EEA's compliance filing to Decision 2941-D01-2015 as filed, with the exception of the backstop supply mechanism, for which EEA was directed to file a new application in Proceeding 20342.

AltaGas Utilities Inc. Rule 004 Exemption Compliance Filing (Decision 21211-D01-2016)
Compliance Filing – Exemption – Tariff Billing – Rule 004

AltaGas Utilities Inc. ("AltaGas") filed its compliance application with the AUC pursuant to the directions made by the AUC in Decision 20428-D01-2015, concerning AltaGas' request for an exemption to section 3.2, Table 301, Ref ID 14 and 15, section 4.3.1(4) and 5.4.1(1) and 5.4.1(2) of Rule 004: *Alberta Tariff Billing Code Rules* ("Rule 004").

The AUC approved AltaGas' revised compliance plan as filed, to be effective on December 31, 2018, the same date that the exemptions expire. AltaGas' compliance plan is posted on the AUC's website, and can be found here.

ATCO Gas 2016 Transmission Service Charge (Rider T) (Decision 21248-D01-2016)
Rate Rider – Tariff

ATCO Gas, a division of ATCO Gas and Pipelines Ltd. ("ATCO") applied for approval of its 2016 transmission service charge ("Rider T"), to be effective on March 1, 2016 as follows:

	Existing Transmission Service Charge ($)	Proposed New Transmission Service Charge ($)
Low (per gigajoule (GJ))	0.738	0.814
Mid (per GJ)	0.703	0.760
High (per day of GJ demand)	0.208	0.226

ATCO submitted that NOVA Gas Transmission Ltd. ("NGTL") received approval for the interim rates, tolls and charges for the Alberta system from the National Energy Board in November 2015. The FT-D3 (intra-Alberta delivery) rate increased to $6.09 per GJ/month, from $5.46 per GJ/month, while the abandonment surcharge was decreased from $0.33 per GJ/month to $0.32 per GJ/month.

ATCO submitted that it calculated the 2016 Rider T amount as the FT-D3 rate charged to ATCO by NGTL, multiplied by the contract demand ("CD") quantity, and the NGTL abandonment surcharge amount, multiplied by the CD quantity. ATCO also included amounts to true-up the amount of 2015 revenue collected and revenues collected for Rider T in January and February 2016.

The AUC noted that prior to Decision 2014-062 dealing with Rider T, separate rates were ordered for north and south service areas in Alberta. In Decision 2014-062, the AUC found that the level of cross-subsidization between customer bases was immaterial, at less than $2 per customer on an annual basis. The AUC ordered ATCO to provide an analysis of whether to continue the practice of levying separate Rider T rates to the north and south service areas in ATCO's next application for Rider T.

ATCO submitted that, if north and south Rider T rates were calculated separates, customers in northern Alberta would see an increase of $3.92 per year on a typical bill, while southern Alberta customers would see a $4.16 decrease in the per year on a typical bill.

The AUC found that the level of cross subsidization, being a $3.92 subsidy from customers in the north, offset by a $4.16 cost to customers in the south, was not material, and approved the Rider T charges as filed.

The AUC found that the proposed province-wide Rider T rates would provide lower costs for northern Alberta users than if Rider T was calculated separately. The AUC also made note that this was the third year in which a province wide Rider T was applied, and also the third year in which southern service area customers have subsidized the costs of northern service area customers. The AUC further noted that the level of cross-subsidization has increased with each subsequent year.

Given the ongoing cross-subsidization, the AUC directed ATCO to track the level of cross-subsidization and present that information with its next Rider T application.

The AUC determined that, if in ATCO's next Rider T application, the subsidy from southern service area customers to northern service area customers exceeds the $4.16 annual amount approved in this decision, ATCO must provide a detailed analysis of how each of the billing determinants contributes to the level of cross-subsidization, and to investigate any other potential causes of cross-subsidization. Accordingly, the AUC also directed ATCO to explain, in its next Rider T application, to explain why the continued use of a province-wide rate would or would not be in the public interest.

AltaGas Holdings Inc. Time Extension to Power Plant Approval 3547-D02-2015 (Decision 21307-D01-2016)
Time Extension – Facilities

AltaGas Holdings Inc. ("AltaGas") submitted an application to the AUC for a time extension to construct the AltaGas Kent Energy Plant, a 95-megawatt natural gas fired power plant, with a 13.8/144-kilovolt step-up substation (the "Project"), located near Cold Lake, Alberta.

AltaGas originally received approval to construct the Project with a deadline of May 31, 2016 to complete construction. AltaGas requested a two-year time extension, arising from its extended discussions and consultations with the Cold Lake First Nations, and cited uncertainty related to the Government of Alberta's Climate Leadership Plan. AltaGas noted that it would need additional time to evaluate potential impacts and reassess its investment decision in relation to the Project.

The AUC held that AltaGas has provided information on the need and duration for the extension and approved AltaGas' request as filed.

FortisAlberta Inc. 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast (Decision 20497-D01-2016)
Capital Tracker – True-Up – Rates

FortisAlberta Inc. ("FAI") applied for approval of its 2014 capital tracker true-up and 2016-2017 capital tracker forecast under performance based regulation ("PBR"). Fortis applied for the revenue requirement associated with its capital trackers to be included in the K factor component of the PBR formula for the applicable year.

The 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 in 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 material exogenous 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.

In order to receive capital tracker treatment under PBR, a capital project or program must meet the following three criteria established in Decision 2012-237:

- The project must be outside of the normal course of the company's ongoing operations ("Criterion 1");
- 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
- The project must have a material effect on the company's finances ("Criterion 3").

FAI applied for capital tracker treatment for the following amounts:

- An additional $0.3 million in K factor revenue from its compliance filing provided for in Decision 3220-D01-2015 (being FAI's last capital tracker approval from the AUC);
- A reduction of $4.2 million to its 2014 K factor revenue, taking into account actual capital additions and related costs, updated debt rates and weighted average cost of capital

assumptions, as well as amounts provided for in Decision 3220-D01-2015; and

- Forecast K factor revenue of $71.5 million for 2016 and $89.9 million for 2017.

FAI's 2013 and 2014 capital tracker true-up amounts that are the subject of this decision were applied for as follows:

($ million)	2013 Prior	2013 Current	2014 Prior	2014 Current
Customer Growth	5.5	5.6	17.5	13.6
AESO Contributions	6.7	6.7	11.7	10.4
Substation Associated Upgrades	1.6	1.7	3.6	3.9
Distribution Line Moves	0.8	0.8	2.1	1.3
Urgent Repairs	0.5	0.5	1.4	1.1
Distribution Capacity Increases	-	-	-	-
Metering Unmetered Oilfield Service	0.5	0.5	0.4	0.4
Worst Performing Feeders	-	-	0.4	0.4
Pole Management	0.6	0.8	1.7	1.7
Compliance, Safety, Aging Facilities, and Reliability	0.5	0.5	1.0	0.7
Cable Management	-	-	0.4	0.4
Distribution Control/SCADA	0.8	0.8	2.0	4.0
Total	**17.4**	**17.7**	**42.2**	**38.0**

FAI's applied-for capital projects and programs for the 2016-2017 forecast period were all previously approved for capital tracker treatment in Decision 2013-435, Decision 3220-2015 or in Decision 201351-D01-2015.

FAI applied for the following amounts for the 2016-2017 forecast period:

($ million)	2016 forecast	2017 forecast
Customer Growth	28.0	32.5
AESO Contributions	14.9	20.9
Substation Associated Upgrades	6.1	7.9
Distribution Line Moves	3.5	4.0
Urgent Repairs	2.6	3.1
Distribution Capacity Increases	0.9	1.4
Metering Unmetered Oilfield Service	1.6	2.5
Worst Performing Feeders	1.1	1.4
Pole Management	7.1	9.1
Compliance, Safety, Aging Facilities, and Reliability	1.8	2.3
Cable Management	1.4	2.0
Distribution Control/SCADA	2.4	2.7
Total	**71.5**	**89.9**

Project Groupings

The AUC, in Decision 2013-435 and Decision 3220-D01-2015 approved a number of FAI's project groupings. The AUC noted that where such groupings persist in this decision, they were not considered further and were approved as filed. Therefore the AUC considered only the project and program groupings for Distribution Capacity Increases, Metering Unmetered Oilfield Services, and the Compliance, Safety, Aging Facilities and Reliability

("CSAR"), the Worst Performing Feeders, and Urgent Repairs.

Distribution Capacity Increase projects are comprised of capacity increases, system improvements, system neutrals and line loss reduction. FAI submitted that the grouping was appropriate to avoid duplication in mitigating load growth issues. FAI noted for example that increasing conductor size to mitigate overloading also reduces line losses.

The Consumers' Coalition of Alberta ("CCA") argued that the programs have little to do with one another, based on nomenclature alone, and recommended that the projects be split into four separate categories.

The AUC held that project grouping was essentially an account exercise, and that the optimal manner by which a group of projects is managed is not a valid reason to group projects for capital tracker treatment. As such, the AUC did not accept FAI's Distribution Capacity Increases grouping on the basis that the grouping avoids duplication of effort. However, as the historical cost breakdowns were not available, the AUC approved the grouping for the purposes of the PBR term.

With respect to Metering Unmetered Oilfield Services, FAI submitted that it included conversion from three-wire to four-wire services within the program, since it allows for efficiencies in design and construction, and required only one contractor site visit to achieve both installations.

Similar to the reasoning for Distribution Capacity Increases, the AUC also did not accept FAI's explanation regarding efficiencies for grouping projects under the Metering Unmetered Oilfield Services umbrella of work. However, citing a lack of separate financial tracking for the individual project components, the AUC approved the grouping for the purposes of the PBR term. The AUC directed FAI to track all projects concerning the repair, replacement and installation of meters in a single grouping going forward.

The CCA submitted that the Urgent Repairs, Worst Performing Feeders and CSAR, were essentially all maintenance driven programs, with the only distinction between the three being timing of execution. Therefore the CCA recommended that the AUC order FAI to group the Urgent Repairs, Worst Performing Feeders and CSAR into a single program.

The AUC agreed with the CCA's submissions regarding Urgent Repairs, Worst Performing Feeders and CSAR, finding that the programs share a common requirement for capital investment. The AUC directed FAI to group the Urgent Repairs, Worst Performing Feeders and CSAR programs together in its compliance filing and future capital tracker applications.

Criterion 1 Assessment

FAI provided business cases and engineering studies for each of the projects or programs applied for, consistent with the minimum filing requirements set out in Decision 2013-435 and Decision 3558-D01-2015.

The AUC approved all of the forecast business cases and engineering studies as applied for, finding that the proposed scope, level, timing and forecast costs for the programs applied for continued to be reasonable. The AUC also held that the amounts included by FAI were prudent, subject to certain adjustments made elsewhere in this decision.

FAI applied the following inputs in its forecasts for 2016 and 2017:

- Consumer Price Index ("CPI") Alberta - 2.2%
- Gross Domestic Product growth - 1.7 %
- Housing Starts - 32,017

FAI confirmed that it applied the same forecasting methods as approved in Decision 3220-D01-2015.

The AUC found that FAI's forecasting methods were the same as those approved in Decision 3220-D01-2015. The AUC held FAI's forecast values for CPI, GDP and housing starts, to be reasonable and approved them as filed.

FAI applied for a technical update to its depreciation figures based on actual capital additions in the period since its last capital tracker approval. However, the AUC held that allowing a company to file a depreciation study, or a depreciation technical update was inconsistent with the third PBR principle, namely that the PBR plan should be easy to understand, implement and administer. The AUC held that the introduction of a depreciation technical update was not warranted in this case. The AUC noted that the only circumstance in which it would accept a depreciation technical update was for a Z factor adjustment (a material exogenous event for which the company has no other cost recover mechanism available). The AUC denied the technical update for depreciation rates on the basis that such adjustments would not comport with the object of PBR to reduce the regulatory burden, and provide an established revenue framework during the PBR period. The AUC directed FAI to remove the updated depreciation amounts from the K factor calculation in its compliance filing.

The AUC generally approved of all of FAI's proposed capital tracker projects and programs. However, the AUC held that because the adjustments to the I-X mechanism and depreciation amounts affected the program costs for 2016 and 2017, it was unable to make a final determination as to whether FAI's programs or projects met the assessment requirements for Criterion 1. The AUC therefore directed FAI to update its accounting test parameters for its applied for projects and programs in its compliance filings to reflect the AUC's findings in this decision.

Criterion 2 Assessment

FAI confirmed that the drivers for each of its previously approved programs and projects have not changed, and that its programs and projects were each approved in Decision 3220-D01-2015 as having met the requirements of Criterion 2.

The AUC held that there was no need to undertake a reassessment of any of the projects or programs against the Criterion 2 requirements.

Criterion 3 Assessment

Criterion 3 is a two step materiality test which assesses the impact of capital tracker costs at four basis points of total revenue requirement for individual projects or programs, and 40 basis points of total revenue requirement for the total capital tracker costs not covered by the I-X mechanism for the applicable year.

For its 2014 capital tracker true-up, FAI applied a four basis point threshold of $0.341 million and a 40 basis point threshold of $3.409 million, which it submitted were previously approved in Decision 3220-D01-2015. FAI also submitted that each 2014 capital tracker project or program satisfied both materiality requirements of Criterion 3.

For 2016-2017, FAI submitted that it calculated the materiality thresholds consistent with the methodology set out in Decision 2013-435. However, since FAI did not have approved inflation factors for 2016 or 2017, it used the approved 2015 inflation factor of 1.49 percent for both 2016 and 2017. Accordingly, FAI calculated its 2016 materiality thresholds as follows:

- Four basis point threshold: $0.351 million; and
- 40 basis point threshold: $3.512 million.

FAI calculated its 2017 materiality thresholds as follows:

- Four basis point threshold: $0.356 million; and
- 40 basis point threshold: $3.564 million.

None of the interveners to the proceeding took issue with FAI's calculations.

The AUC held that FAI's calculations and forecasting methods were reasonable. The AUC accordingly approved FAI's 2014 threshold values as filed, and confirmed that the 2014 true-up values met the materiality thresholds of Criterion 3 for capital tracker treatment. However, since the filing of FAI's application, the AUC provided a final 2016 I-X value of 0.90 percent in Decision 20818-D01-2015. Therefore, the AUC directed FAI, in its compliance filing, to apply materiality thresholds for Criterion 3 using the approved 2016 I-X factor as a forecast value for both 2016 and 2017.

Order

The AUC directed FAI to file a compliance filing for its 2014 PBR Capital Tracker True-Up and 2016-2017 PBR Capital Tracker Forecast in accordance with the findings in this decision on April 1, 2016.

ATCO Pipelines 2015-2016 General Rate Application (Decision 3577-D01-2016)
Tariff – Rates – Revenue Requirement

ATCO Pipelines, a division of ATCO Gas and Pipelines Ltd. ("ATCO") applied for approval for its forecast revenues of $214,728,000 for 2015 and $250,362,000 for 2016. ATCO later updated its applied-for revenue requirements as follows:

- $210,233,000 for 2015; and
- $245,472,000 for 2016.

ATCO's previously approved interim revenue requirement was $17,157,800 per month, or $205,893,600 per year, representing 60 percent of ATCO's requested increase for its 2015 revenue requirement.

The updated applied for revenue requirement represented an overall reduction of $9,385,000 over the test period applied for, resulting primarily from the following factors:

- Decision 2191-D01-2015, being the generic cost of capital proceeding, which reduced ATCO's equity ratio from 38 to 37 percent, and reduced the return on equity to 8.30 percent from 8.75 percent for 2015;
- Decision 19756-D01-2015, which denied the House Mountain project.
- Reductions to ATCO's forecast Urban Pipeline Replacement ("UPR") program; and

- Other reductions and adjustments to rate base and expenses, largely as a result of when certain projects went into service, and subsequent depreciation revisions.

ATCO explained that the revenue requirement would be collected from NOVA Gas Transmission Ltd. ("NGTL") according to the terms of the integration between the two pipeline systems owned by NGTL and ATCO.

ATCO also sought approval from the AUC for:

- Forecast opening balances for plant, property and equipment ("PP&E") as at January 1, 2015;
- Continued use of deferral accounts and placeholders;
- Proposed depreciation rate changes; and
- Proposed settlement of certain regulatory deferral accounts.

Rate Base

ATCO's requested rate base was applied for as follows:

($000)	2013 actual	2014 estimate	2015 forecast	2016 forecast
Mid-year plant in service	$843,187	$946,052	$1,116,419	$1,375,186
Necessary working capital	$28,006	$25,421	$27,443	$29,385
Rate Base	**$871,193**	**$971,473**	**$1,143,862**	**$1,404,571**

The AUC held that ATCO's requested rate base was reasonably calculated. However, the AUC found that, in reviewing ATCO's revised revenue requirement, some financial schedules did not align with the initial applied for amounts. The AUC therefore directed ATCO, in its compliance filing, to provide a confirmation to the AUC that the financial schedules were consistent with the revised information.

Capital Expenditures

ATCO included the following figures for its forecast capital expenditures over 2015 and 2016, as well as actuals and estimates for 2013 and 2014 as follows:

(All figures $000)	2013 actual	2014 estimate	2015 forecast	2016 forecast
Total Capital Expenditures	145,890	182,297	309,994	249,748
Contributions	24,906	14,976	1,200	1,120

ATCO noted that the growth in capital expenditures were largely driven by growth in NGTL's FT-D2 delivery service, largely in the Alberta industrial heartland, and FT-D3 utility delivery service for companies in ATCO's service area.

Interveners, including the Consumers' Coalition of Alberta ("CCA") and Utilities Consumer Advocate ("UCA") expressed concerns with the quality of ATCO's business cases. The CCA and UCA noted deficiencies in the business cases, such as a lack of explanations of need, timing, and a lack of a cost-benefit analysis.

The UCA recommended that ATCO should demonstrate a case for the following three criteria, in submitting capital costs for inclusion in rates:

- that, in the absence of the capital expenditure, service quality and safety would deteriorate;
- why the project timing is optimal, and that the project could not be deferred; and
- a comparison of the project costs of similar projects over the last five year period for each project.

ATCO argued that the interveners placed undue reliance on the requirement for a quantitative cost-benefit analysis. ATCO also submitted that the UCA improperly proposed the application of entirely new business criteria, giving the appearance that the traditional business case criteria were inadequate.

ATCO submitted that its business cases continued to comply with the AUC's directives in Decision 2000-9, which required the following information for major capital projects:

- A detailed justification, including demand, energy and supply information;
- A breakdown of the proposed cost;
- Options considered and their economics; and
- The need for the project.

The City of Calgary argued that ATCO Pipelines had not followed previous business case directives from the AUC in Decision 2000-9, and did not discharge its onus to show that the expenditures were necessary. Accordingly, the City of Calgary recommended that the AUC disallow ATCO's requested costs for project which did not meet these requirements.

ATCO also pointed to Decision 3539-D01-2015, wherein the AUC held that the exact criteria proposed by the UCA were rejected, noting the further volume and complexity that would be added to rate proceedings.

The AUC held that the additional criteria proposed by the UCA were similar to performance-based regulation criteria, and should not apply to the cost-of-service regulation context, consistent with Decision 3539-D01-2015.

The AUC, in providing its findings on this point, expanded on the four criteria set out in Decision 2000-9 as follows:

- The detailed justification should include an overall requirement for the project, how the project fits into the existing infrastructure, and any drivers of the project;
- The breakdown of costs should also include an estimation of new operational expenses as a result of the capital cost expense, if the project is put into rate base before the end of the test period;
- The options considered should include a discussion to support a cost-benefit analysis for the preferred alternative, and provide a clear rationale for the preferred alternative; and
- The need for the project should include the rational of need for the project as outlined under Rule 020: Rules Respecting Gas Utility Pipelines, including information as to the growth, replacement, improvement, safety, quality of service, or some combination thereof, as well as an estimate of timing for the project.

The AUC held that ATCO's business cases lacked relevant information, including the costs for project alternatives and impacts on operating costs. Despite this finding, the AUC held that it was not prepared to apply a general reduction to ATCO's forecast, citing its findings related to specific capital projects, and capital expenditure forecasting accuracy in this decision.

<u>Capital forecasting accuracy</u>

The Canadian Association of Petroleum Producers ("CAPP") argued that ATCO had not demonstrated the ability to accurately forecast capital expenditures, noting prior variances of \$1.2 million and \$47.4 million for 2013 and 2014 respectively. CAPP noted that ATCO significantly over-forecasted capital expenditures over the last four year period, creating excess rates of return on equity for actual capital expenditures. CAPP submitted that since 2010, ATCO's actual return on equity has been between 1.08 to 2.78 percent above the approved ROE, due in part to over-forecasted capital expenditures. CAPP proposed that the capital expenditures be treated on an "actual" or annual deferral account basis. The UCA made similar submissions supportive of CAPP's general position on this issue.

ATCO argued that it was on target with its necessary applied-for capital work for the 2013-2014 test period, based on its most recent figures. ATCO disagreed that any capital reduction, let alone an arbitrary general reduction was warranted, submitting that ATCO had a good record of forecasting capital expenditures and improving trends in this regard.

The AUC held that the evidence demonstrated ATCO having a history of over-forecasting capital expenditures and capital additions. Therefore an adjustment to forecast capital expenditures was reasonable in the circumstances for certain categories of capital expense.

For replacement and improvement capital expenditures, the AUC directed ATCO to reduce its forecast by 10 percent, given the historical information on forecast variances.

The AUC rejected CAPP's proposal for deferral treatment, however holding that capital expenditures are best examined on a forecast, prospective basis. The AUC noted that, if capital expenditures were subject to deferral accounts, no incentive would exist for ATCO to manage its forecast capital costs.

The AUC held that no adjustments were necessary for ATCO's UPR program or any NGTL directed growth capital expenditures. The AUC did however voice its concern with the lack of transparency and confidential nature of NGTL's approval for UPR projects, calling it a serious concern. The AUC therefore directed ATCO to provide more detailed information to support the hydraulic analysis, technical and financial justification for its pipeline projects, including NGTL's rationale for its approvals.

However, due to a number of re-bids on UPR projects, and noting a number of reductions, ATCO also proposed a deferral account to provide benefits to customers from future tenders below the original forecast.

Both the UCA and CAPP supported the use of a deferral account for UPR projects.

The AUC approved the use of the deferral account for UPR projects, and directed ATCO to provide an update on its efforts to reduce UPR capital costs in its compliance filings, as well as the actual costs for projects in the 2015 test year.

Any forecast capital expenditures not specifically noted by the AUC were approved as filed.

UPR Procurement Process

The AUC noted that the UPR capital forecast costs increased from approximately $369 million to $600 million over a three year period. The UCA submitted that the competitive bid process did not result in competitive pricing, despite flat labour and material costs, since the bid process times were shortened, and that the tendering process was confusing.

ATCO proposed its above noted deferral account to remedy the UCA's concerns. ATCO also argued that the bid process was robust, with good depth of qualified bidders.

The AUC held that ATCO's bid process was reasonably competitive, and had a sufficient number of bidders. However, the AUC agreed with the UCA, finding that the cost increases were significant and material to customers. Therefore the AUC reiterated its finding approving the deferral account treatment to UPR capital expenditures in the test period, which will afford parties an opportunity to provide submissions on the costs to be recovered related to the procurement process.

Inland Looping Project

ATCO proposed the construction of the Inland Looping Project, which is approximately 26.7 kilometers of 508 millimeter pipeline, looping the Inland transmission system from the western end of the Norma transmission to the junction of the Inland Wye system. ATCO estimated the cost at approximately $52 million with an in-service date of November 2016.

However, ATCO, in response to an information request, noted that NGTL no longer supported the full Inland Looping Project, but only 18 kilometers of the project, at a reduced cost of $40 million due to changes in forecast supply and demand on the Alberta system.

None of the interveners opposed the inclusion of the Inland Looping Project.

The AUC held that the Inland Looping Project was approved for inclusion in the NGTL directed growth capital deferral account.

H2S Warning Lights at 45 stations

ATCO applied for inclusion of $685,000 in forecast costs for installation of a standard hydrogen sulfide ("H2S") warning light and horn system at 45 stations that may receive gas containing H2S.

The CCA submitted that ATCO's business case had not confirmed the contractual status of any of the 45 stations, and incorrectly included eight stations that were the subject of an asset swap with NGTL.

The AUC held that ATCO's business case was acceptable, but did not directly address the CCA's concerns. ATCO's testimony revealed that there was doubt as to whether there was a need to upgrade all of the stations in the test years. The AUC accordingly reduced the forecast estimate by the average station cost for eight stations, resulting in a disallowance of $180,444 split between the two test years. The AUC directed ATCO to reflect this reduction in its compliance filing.

Edmonton Office Expansion

ATCO proposed to construct an expansion to its existing ATCO Pipelines Edmonton Centre ("APEC"), adding 75 workstations to accommodate the increased number of permanent office employees in Edmonton, at a cost of $8.5 million.

ATCO argued that the 40-year cumulative net present value cost of service alternative for a lease was calculated at $12,743,000 for similar service.

The CCA disagreed with ATCO's projections, noting that a 40 year period was too long to predict the need for staff. The CCA therefore requested an updated forecast of office space needs for expected full-time equivalents in its compliance filing.

The AUC accepted ATCO's argument that the construction of new space would provide a lower cost of service than leasing new space. However, in light of recent announcements of staffing reductions, ATCO was directed to file an update to its APEC business case in its compliance filing.

Asset Management Projects

ATCO filed for inclusion of the following asset management program costs in the test period:

- Maximo Phase 2;
- Hyperion; and

- Enchancements to Geographic Information System ("GIS"), Pipelines Integrity Management System ("PIMS") and Maintenance Management System ("MMS").

ATCO stated that the Maximo software is intended to automate time entry, and become a central repository for pipeline and facility maintenance data. The total cost of Maximo Phase 2 was estimated at $1,250,000. The Hyperion budgeting and planning system would support budgeting and forecasting, the development of regulatory applications and modelling and simulation abilities. The total cost of Hyperion implementation was estimated at $1,600,000 with $150,000 in annual costs.

ATCO submitted that the GIS, PIMS and MMS projects did not exceed the $500,000 threshold for business cases, and therefore provided detail as requested through the information request process. ATCO noted that the forecast expenditure for GIS, PIMS and MMS over the forecast period was equal to approximately $3.35 million.

The City of Calgary submitted that ATCO's asset management expenditures were approximately $5.0 million, and were not supported by a quantification of benefits to consumers. Calgary therefore recommended that the AUC disallow $4.95 million in forecast asset management capital costs, as follows:

- Maximo Phase 2 – $0.75 million;
- GIS, PIMS, MMS enhancements – $2.6 million; and
- Hyperion – $1.6 million.

The CCA took issue with ATCO's subdivision of projects into smaller pieces for what it referred to as avoiding their consideration in a larger business case. Accordingly, the CCA requested that the smaller projects be excluded from rate base as a result of ATCO not properly documenting the need for these projects.

The AUC held that the GIS, PIMS and MMS enhancements, while below the $500,000 threshold, represented significant amounts over the test period, when considered in aggregate. The AUC also agreed with the City of Calgary that ATCO failed to provide a cost-benefit analysis related to its Maximo Phase 2 and Hyperiod projects. The AUC denied ATCO's costs for these three asset management projects, and directed ATCO to remove $4.95 million worth of capital expenditures from the test years.

<u>NGTL Asset Transfer</u>

The AUC noted that ATCO had entered into an agreement with NGTL to transfer approximately 393 pipeline segments totalling 1,249 km in length to NGTL, and to receive approximately 171 pipeline segments totalling 1,440 km in length from NGTL, as well as approximately 85 meter stations and one compressor station. ATCO submitted that the net effect of the asset swap would be a cumulative savings of approximately $34 million, including operations and maintenance costs over the test period. However, ATCO noted that these amounts would be offset by NGTL savings, resulting in a minimal net effect on the Alberta system cost of service. ATCO submitted that any true-up would be captured through the NGTL integration deferral account. In all, ATCO submitted that the impact of the asset swap would be a net cost of $2.2 million to ATCO due to higher land rights payments being transferred, as well as the cost of the additional metering stations.

The AUC held that the one-time capital, one-time operations and maintenance costs, and annual operations and maintenance costs were reasonable. The AUC stated it was cognizant that some one-time costs are necessary for asset transfers, and approved each set of costs as filed. The AUC also approved a placeholder amount of zero, noting that any true up would be captured under the NGTL integration deferral account in a future proceeding.

<u>Necessary working capital</u>

ATCO did not propose any material changes to the lead-lag days approved in its previous 2013-2014 general rate application. However, ATCO did request that the AUC approve the removal of deferral account balances from the calculation of necessary working capital, and instead allow the accrual of carrying costs on approved deferral accounts on a monthly basis.

The UCA recommended an adjustment to the necessary working capital for ATCO to reflect ATCO's practice of capitalizing capital additions well after mid-year. The UCA explained that capital additions are assumed to occur regularly when capitalized at mid-year, although ATCO often reaches 50 percent capitalization of its capital expenditure in October of each year. That presumption, according to the UCA, underpins a number of rate base calculations used to calculate the utility's return. Accordingly, the UCA requested that the AUC adjust ATCO's applied for necessary working capital by $2.8 million in 2015 and $2.9 million in 2016.

ATCO submitted that the UCA's proposal was not appropriate, and would deviate from the mid-year convention of capitalizing costs.

The AUC determined that the UCA's proposal was not meant to deviate from the mid-year convention, but would instead adjust the lead-lag study to account for lag days in capital additions owing to the fact that ATCO's capital additions routinely fall after the mid-year. However, the AUC was not persuaded to revise its calculation of necessary working capital, given the AUC's recent findings in Decision 3539-D01-2015, where it found that mid-year capitalization is a long-standing convention. In that decision, the AUC also found that additional tracking of lag days would add unnecessary complexity to the calculations.

The AUC therefore approved ATCO's necessary working capital calculations as filed. However, the AUC directed ATCO to provide a further explanation of why its capital additions lag the mid-year convention, and whether it is appropriate to include the capital additions or other capital related items in the necessary working capital.

Operating costs

ATCO's forecast operating costs were stated as follows for the test period:

	2015 forecast ($million)	**2016 forecast ($ million)**
Operations and Maintenance	34.4	38.5
Administration and General	32.3	33.5
Less disallowed operating costs	(2.0)	(2.0)
Total	**64.7**	**70.1**

Each year's costs, according to ATCO represented 31 and 28 percent of forecast revenue requirement, respectively. ATCO noted that it included a reduction of $2.0 million in each year for costs previously disallowed by the AUC, notably the pension cost of living allowance, and incentive program costs.

ATCO's operating costs decreased by 31 percent from 2010 to 2014. However, ATCO noted that the requested operating costs for the test period increased in 2015 from 2014 actual values by $6.0 million, or 21 percent. In 2016, the figures increased over 2015 values by $4.2 million, or 12.4 percent.

None of the interveners submitted views on the overall forecast operating costs.

The AUC approved ATCO's requested operating costs as filed, except where specifically excluded elsewhere in the decision.

Salary Escalators

The CCA submitted that the current Alberta labour market, given the market conditions, did not support ATCO's requested escalation of 3.5 percent per year for 2015 and 2016 for its unionized labour. ATCO's current labour agreements include a salary escalator of 3.5 percent for 2014 and 2015, but no agreement has been reached for 2016.

The CCA submitted that the AUC limit labour inflation rates to zero percent for any labour contracts not settled at the time of the hearing. CAPP submitted that any incomplete salary escalators for the test period be subject to deferral account treatment.

The UCA argued that it was disingenuous for ATCO to cut labour costs for the account of its shareholders in claiming a surfeit of labour talent, while simultaneously asking the AUC to approve labour cost increases paid by constumers to retain and attract talent.

ATCO submitted that CAPP's proposal would not materially affect rates, noting that a one percent adjustment to in-scope salaries would amount to approximately $92,000. ATCO also argued that the UCA was "completely off the mark" with its allegations of disingenuous conduct, as any cost savings from labour costs would be for the account of ratepayers, not shareholders.

The AUC held that a deferral account for 2016 labour escalators was not necessary, finding that any adjustments would not likely meet the materiality criteria for deferral treatment.

However, the AUC reduced ATCO's requested salary escalator for 2016 from 3.5 percent to 3.0 percent, based on the evidence provided by ATCO respecting current labour market conditions.

For non-union employees, ATCO requested salary escalators of 4.2 percent for 2015 and 2016, based on forecast labour market data. However, during the hearing, ATCO updated these figures to reflect changes in the market. Accordingly, ATCO updated its labour market data for non-union salary escalators to 3.0 percent for 2015 and 2016, but left its requested increase at 4.2 percent. ATCO maintained its requested increase, pointing to the fact that its overall compensation lags the market by 15 percent.

CAPP disagreed with ATCO's requested non-union labour increases, as CAPP argued that ATCO's inflation factors were based on unrepresentative averages needed to compensate employees at a competitive level.

The UCA agreed with ATCO's updated submission on salary escalators, and recommended an increase of 3.0 percent for 2015 and 2016.

The AUC held that the evidence before it did not support a 4.2 percent salary increase for non-union labour, pointing to the evidence presented by ATCO that such labour escalators are trending downward.

The AUC further did not accept ATCO's rationale that it lagged the market by 15 percent. The AUC noted that, when looking at base salary, ATCO was on average 2 percent above the 50^{th} percentile, and it was not reaonsable to escalate base salaries to balance out its total compensation. The AUC held that there were other means at ATCO's disposal to manage its total compensation.

The AUC therefore approved a 3.0 percent salary escalation factor for 2015 and 2016 for non-unionized labour, and directed ATCO to reflect this finding in its compliance filing.

Variable Pay Program

ATCO submitted that it implemented a new variable pay program ("VPP") pursuant to an approval in AUC Decision 2013-430. The VPP, in ATCO's submission, was based on individual performance and the performance of the employee's department. ATCO did not forecast an extension of the VPP through 2015-2016, but would continue to monitor and evaluate the need to adjust the VPP as the market dictated.

The CCA argued that there was no VPP paid out in 2014, and consequently requested that the AUC deny ATCO's forecast VPP amounts for 2015 and 2016.

ATCO replied that it must retain the ability to react to the marketplace to attract and retain employees.

The AUC noted that ATCO acknowledged that any VPP amounts not paid out will be refunded to consumers. Accordingly, the AUC held that the forecast VPP amounts of $2.628 million in 2015 and $2.766 million in 2016 for VPP were reasonable, as any unpaid amounts would be refunded through a variable pay deferral account, which it also approved.

FTE Forecasts

ATCO forecasted an additional 36 FTEs in 2015 and an additional 10 FTEs in 2016. ATCO submitted that total FTEs would be 470 at year end 2015, and 480 at year end 2016.

CAPP requested that any forecast positions currently unfilled be disallowed, and any positions not filled in a timely manner be removed from the forecast FTEs in the test period.

The CCA took issue with ATCO's announcement in late 2015 that it would be reducing staff, but not placed on the record by ATCO. The CCA submitted that the compliance filing must include information on the effects of restructuring within ATCO.

The AUC directed ATCO to clearly identify the impact of announced employee reductions on forecast FTEs and revenue requirement. Accordingly, the AUC approved the FTE costs on a placeholder basis until the impact of the reductions is tested in the compliance filing.

Return on Rate Base

ATCO requested a return on equity of 8.30 percent for 2015, with a capital structure of 37 percent equity and 63 percent debt for 2015. ATCO requested that the same return on equity and capital structure be approved on a placeholder basis for 2016, since the AUC's most recent generic cost of capital decision 2191-D01-2015 applies only to the 2015 test year.

The AUC approved ATCO's requested return on equity and capital structure as filed, noting that the figures were compliant with Decision 2191-D01-2015.

Debt Rate

ATCO requested a cost of debt equal to 4.00 percent for 2015 and 4.65 percent for 2016.

The CCA recommended that the AUC apply ATCO's most recently obtained rate for a debenture offering, at 3.964 percent, and further recommended a 2016 forecast debt rate of 3.99 percent, based on 10-30 year bond differentials, ATCO's credit spread, and the consensus forecast for 10 year bond rates.

The AUC approved ATCO's 2015 debt rate at 3.964 percent holding that, since the actual cost of debt for 2015 was known, it would apply actual data where available over forecast data.

For ATCO's 2016 debt rate, the AUC approved a debt rate of 4.29 percent. The 10-30 year bond differential raised by the CCA created an "implied long Canada bond rate" of 2.49 percent, which was 0.66 percent lower than ATCO's forecast long Canada bond rate of 3.15 percent, which was offset by ATCO's updated credit spread of 180 basis points. Accordingly, the AUC approved the 4.29 percent debt rate for 2016 on a final basis.

Deferral Accounts

ATCO requested that the AUC approve the following deferral accounts for the test period:

Deferral Account Name	2014 closing balance ($)	Settlement amount ($)
Deduction of Deferrals for tax purposes	591,000	591,000
NGTL Integration	346,000	0
NGTL Directed Growth Capital Deferral	183,000	183,000
Salt Cavern Working Gas	(175,000)	0
Reserve for Injuries and Damages	(175,000)	0
Regulatory Expenses	(715,000)	0
VPP	(848,000)	(848,000)
2013-2014 pension funding	(1,322,000)	0
UPR	(730,000)	(730,000)
Negotiated Settlement Pension Funding	(309,000)	(309,000)
Total Recovery	**(2,553,000)**	**(512,000)**

The AUC approved the amounts in the table above, as filed, with the exception of regulatory expenses and regulatory or legislative changes.

CAPP recommended that, for the regulatory expenses deferral account, that ATCO's hearing costs and AUC operating costs be settled simultaneously when combining both categories of expenses.

The AUC agreed, holding that settling both cost categories would assist the AUC in tracking costs included in the deferral account on a go-forward basis.

ATCO requested the continued use of its regulatory or legislative changes deferral account to provide protection from the impact of changes to legislation that may arise during the test period.

The AUC denied ATCO's request, holding that there was no evidence with regard to a forecast amount expected during the test period, nor was there any evidence addressing the uncertainty or inability to forecast the amounts needed. While the AUC noted that such changes are beyond the control of ATCO, the AUC held that such changes are typically made with advance consultation with stakeholders, and that changes typically take time to implement.

Depreciation

ATCO included a technical update to its last depreciation study in the application. ATCO provide updated depreciation rates for 2015 and 2016 test years based on plant in service balances, as of December 31, 2013. ATCO submitted the effect of the updated amortization was an increase in depreciation expense at $1.39 million.

The AUC accepted ATCO's evidence, and approved the updated forecast depreciation rates as reasonable.

Order

The AUC directed ATCO to submit a compliance filing no later than April 14, 2016.

NATIONAL ENERGY BOARD

Board Directions – Energy East Pipeline Ltd. Application for the Energy East Project and Asset Transfer – Status of the Application (February 3, 2016)
Refiling –Facilities Application

The NEB sent a letter to Energy East Pipeline Ltd. ("Energy East") on February 3, 2016 regarding the status of the application for the Energy East Pipeline.

In the letter, the NEB noted that the application was initially filed 15 months prior, with five supplemental reports, five project updates, five documents with errata and replacement pages, and the amendment to the application submitted in December 2015.

The NEB referenced its Information Request No. 3, stating that it expects clear, relevant and timely information to be provided to all potentially affected persons or groups; and that the information be accessible and inclusive.

In consideration of the volume and complexity of the application materials, the NEB found that the application was difficult, even for experts, to navigate. As such, the NEB expressed its concerns about how that may impact the fairness and efficiency of the hearing process.

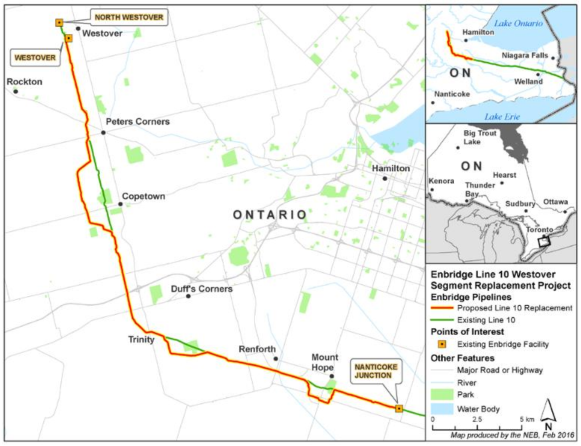
The NEB therefore directed that the application should be revised and consolidated in an updated filing to assist parties to assess the application, and in both official languages. The NEB also requested a list of outdated or superseded documents as part of the updated filing.

Prior to filing the consolidated application, however, the NEB directed Energy East to file, for approval, a detailed table of contents for the application by no later than February 17, 2016.

Enbridge Line 10 Westover Segment Replacement Hearing Order OH-001-2016 (February 17, 2016)
Pipeline Replacement – Hearing Order

The NEB released a hearing order for Enbridge's application to replace the Westover Segment of its line 10 pipeline, which consists of replacing 32 kilometers of existing 12 inch diameter pipeline with approximately 35 kilometers of new 20 inch diameter pipeline from Enbridge's Westover Terminal to its Nanticoke Junction facility in Hamilton, Ontario (the "Application").

The NEB provided a map of the facilities affected by the Application:



The NEB determined that the following issues would be considered in the course of the hearing considering the Application:

- The need for the Application;
- The economic feasibility of the Application;
- Potential commercial impacts of the Application, including supply and market issues;
- The potential environmental and socio-economic effects of the Application;
- The appropriateness of the general route and land requirements for the Application;
- The engineering design and integrity of the Application;
- The potential impacts of the Application on Indigenous interests;
- The potential impacts of the Application on directly affected landowners;
- Contingency plans for spills, accidents or malfunctions during construction and operation of the Application; and

- The terms and conditions to be included in any approval the NEB may issue for the Application.

Information regarding the Application can be found here on the NEB's website. A copy of the hearing order itself can be found here.

Parties who wish to register for the hearing have until March 14, 2016 to apply to participate.

National Energy Board Pipeline Condition Compliance Tracker Released (February 22, 2016)
Pipeline Conditions –Compliance

The NEB, following up on the Commissioner of the Environment and Sustainable Development's ("CESD") recommendation that the NEB improve public access to information about company compliance with approval conditions, released information that allows the public to track company compliance with pipeline approval conditions.

More information regarding the NEB's pipeline approval compliance tracking tool can be found here.

Energy Safety and Security Act Entered Into Force (February 26, 2016)
Legislation – Amendment

The *Energy Safety and Security Act* ("*ESSA*") came into force on February 26, 2016. The *ESSA* amends the *Canada Oil and Gas Operations Act* ("*COGOA*") to provide the NEB with new tools to regulate northern oil and gas activities. The NEB provided the following summary of the key components affecting the *COGOA*:

- $1 billion absolute liability limit in the offshore and new obligations related to "financial responsibility" (i.e. readily accessible funds) and "financial resources" (i.e. overall financial capacity); operators continue to have unlimited liability when they are at fault or negligent.

- Improved transparency through new Board authority to hold public hearings, make some information public, and provide participant funding in relation to certain projects under *COGOA*.

- Once the NEB determines an application for a *COGOA* Authorization is complete, the NEB has 18 months to complete its review.

- Providing the NEB with the authority to establish an administrative monetary penalty ("AMP") regime under *COGOA*.

The *ESSA* also amended the *COGOA* to include two new regulations:

- *Canada Oil and Gas Operations Financial Requirements Regulations*; and

- *Canada Oil and Gas Administrative Monetary Penalty Regulations*.

A full text copy of the *ESSA* can be found here.

Copies of the *Canada Oil and Gas Operations Financial Requirements Regulations and the Canada Oil and Gas Administrative Monetary Penalty Regulations* can be found here.