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DECISIONS

REGULATORY
LAW CHAMBERS

ENERGY REGULATORY REPORT

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

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ALBERTA ENERGY REGULATOR

Observed Seismicity and Oil and Gas Operations: Operators' Responsibilities (Bulletin 2015-03)
Bulletin – Seismicity – Licensee Responsibilities

On February 3, 2015, the AER released Bulletin 2015-03 confirming a seismic event that took place on January 22, 2015 in the vicinity of Fox Creek, Alberta. The seismic event, measuring 4.4 on the Richter scale, was part of a sequence of lower level seismic events near Crooked Lake. The bulletin notes that there were no impacts to the public or the environment.

The bulletin reminds licensees of their responsibility to ensure well control and subsurface integrity in accordance with AER Directive 083: *Hydraulic Fracturing – Subsurface Integrity*, for all stages of drilling, completions, and injection operations.

Joint Operating Procedures for First Nations Consultation on Energy Resource Activities, Including New Application Requirements (Bulletin 2015-04 and Bulletin 2015-10)
Bulletin – First Nations Consultation – Application Requirements

On February 4, 2015, the AER announced the release of the Joint Operating Procedures for First Nations Consultation on Energy Resource Activities, including new application requirements arising from two ministerial orders on aboriginal consultation from the Minister of Energy and the Minister of Environment and Sustainable Resource Development. These new procedures affect requirements for applications under specified enactments (including the *Mines and Minerals Act*, Part 8; the *Water Act*, and the *Environmental Protection and Enhancement Act*).

Although the AER originally planned for these changes to come into effect on March 2, 2015, the AER released Bulletin 2015-10 on February 26, 2015, indicating that implementation of the declaration requirement and the application requirements would be delayed until further notice.

The new procedures expand upon *The Government of Alberta's Guidelines on Consultation with First Nations on Land and Natural Resource Management*, by describing four internal Aboriginal Consultation Office ("ACO") and AER procedures based on AER application type and ACO consultation requirements.

Bulletin 2015-04 provides the following highlights of the new procedures:

(a) The ACO's determination of consultation adequacy is required before the AER can make a final decision under the specified enactments.

(b) The ACO may provide advice to the AER in cases where the ACO believes impacts to Treaty rights and traditional uses need to be considered by the AER.

(c) For an application for which the ACO has determined no consultation was required, the applicant must submit a copy of the pre-consultation assessment with its application to the AER. The AER will process the application after confirming that consultation was not required. (Pre-consultation assessments are submitted in the same manner as the First Nations Consultation Declaration (see next section).)

(d) For an application requiring First Nations consultation, the applicant must submit a First Nations impacts and mitigation table to the AER. (This table is to be included in the First Nations Consultation Declaration (see next section).) The table is to contain information about any potential adverse impacts of the proposed energy resource activity on existing rights of aboriginal peoples as recognized and affirmed under Part II of the *Constitution Act*, 1982, and on traditional uses as defined in *The Government of Alberta's Policy on Consultation with First Nations on Land and Natural Resource Management*, 2013. The information in the table will come from the consultation records already required and verified by the ACO. No new information is required.

(e) For Enhanced Approval Process ("EAP") applications under the *Public Lands Act*, the applicant conducts consultation and seeks an adequacy assessment from the ACO before applying to the AER. Statements of concern received by the AER from a First Nation or other aboriginal group are provided to the ACO.

(f) For non-EAP applications under the *Public Lands Act*, and applications under the *Water Act* and the *Environmental Protection and Enhancement Act*, the AER receives the application and begins its technical review while consultation is ongoing. Statements of concern received by the AER from a First Nation or other aboriginal group are provided to the ACO. The AER will make its final decision on the application after the ACO has assessed consultation adequacy and has possibly provided advice on mitigating impacts to Treaty rights and traditional uses.

(g) For applications requiring extensive consultation, the ACO and AER will ensure that the period for consultation and the period for submitting a statement of concern, end at the same time so that all input can be assessed and considered in the AER's regulatory decision. The ACO will provide the AER with a report that provides the ACO's assessment of consultation adequacy and that may contain advice to the AER on mitigating impacts to Treaty rights and traditional uses.

(h) If the AER holds a hearing on an application, the ACO may observe and may provide a hearing report to the AER containing advice on any impacts to Treaty rights and traditional uses that were raised during the hearing and not previously addressed by the consultation process.

A copy of the joint operating procedures can be found here, on the AER's website.

Oil and Gas Conservation Rules Change Introducing Subsurface Orders (Bulletin 2015-05)
Bulletin – Subsurface Orders – Oil and Gas Conservation Rules

The AER announced an amendment to the *Oil and Gas Conservation Rules* ("*OGCR*"), which now allow for the AER to make subsurface orders. The nature of such new orders is set out in the newly enacted section 11.104 of the *OGCR*:

> 11.104 Notwithstanding sections 3.050, 3.051, 3.060, 4.021, 4.030, 4.040, 7.025, 10.060, 11.010, 11.102 and 11.145, if the Regulator is satisfied that it is appropriate to do so, the Regulator may, on its own motion, issue a subsurface order that
>
> > (a) designates a zone in a specific geographic area, and
> >
> > (b) prescribes requirements pertaining to spacing, target areas, multi-zone wells, allowables, production rates and other subsurface matters within that zone,
>
> in which case if there is a conflict or inconsistency between the subsurface order and any of the sections referred to above, the subsurface order prevails to the extent of the conflict or inconsistency.

Bulletin 2015-05 explains that:

(a) The AER's assessment process will include an evaluation of risks to resource recovery and reservoir equity;

(b) The AER will assess trends in down-spacing and other resource applications to identify potential opportunities for subsurface orders;

(c) Subsurface orders will be announced via bulletin;

(d) Subsurface orders will not alter mineral rights, tenure, or royalty matters; and

(e) Subsurface orders will only address regulatory matters under the AER's jurisdiction, and will not predetermine regulatory approval of any other facilities or activities associated with the development of the resources identified in the subsurface order.

The *OGCR* remains otherwise unchanged from its previous iteration.

Issuance of Subsurface Order No. 1 Regarding the Montney-Lower Doig (Bulletin 2015-06)
Bulletin – Subsurface Order

Pursuant to changes to the *Oil and Gas Conservation Rules* announced in AER Bulletin 2015-05, the AER released Subsurface Order No. 1 effective March 1, 2015 for the Montney-Lower Doig zone (the "SO1").

Subsurface Order No. 1 establishes the following rules in the prescribed area:

(a) There are no well density restrictions for both oil and gas drilling and spacing unites ("DSUs");

(b) The target area for wells drilled within the standard drilling spacing unit for a gas or oil well must be the central area within the drilling spacing unit having sides 100 metres (m) from the sides of the drilling spacing unit and parallel to them, and wells may be drilled across the boundaries of contiguous DSUs of common ownership;

(c) Defined pools within the SO1 area will be subject to good production practice as reflected in the AER's current maximum rate limitation (MRL) order, provided that optimal depletion strategies are employed and wasteful operations are avoided;

(d) Initial pressure tests, in accordance with Directive 040: *Pressure and Deliverability Testing Oil and Gas Wells* ("*Directive 040*"), are required to be taken at a minimum of one well per three section by three section area (square nine section area) measured from the wellhead location;

(e) Annual pressure tests in accordance with *Directive 040* are not required;

(f) Initial deliverability testing in accordance with *Directive 040* is not required; and

(g) Drill cutting samples within the target zone may be taken every 10 m, beginning 30 m above the target zone in horizontal wells.

Bulletin 2015-06 notes that a Subsurface Order does not affect or alter mineral rights, tenure rules, or royalty matters. The bulletin further provides that where a Subsurface Order conflicts with a term or condition in a licence or approval, the terms and conditions found in the licence or approval will prevail.

In order to assess performance and monitor activity within the prescribed area, the AER may require the submission of resource management performance reports, including performance presentations and meetings with participating operators.

A map of the area affected by Subsurface Order No. 1 is provided here, on the AER's website.

Subsurface Order No. 2: Monitoring and Reporting of Seismicity in the Vicinity of Hydraulic Fracturing Operations in the Duvernay Zone, Fox Creek, Alberta (Bulletin 2015-07)
Bulletin – Subsurface Order

The AER released Subsurface Order No. 2 regarding monitoring and reporting of seismicity in the vicinity of hydraulic fracturing operations in the Duvernay Zone in the Fox Creek area of Alberta.

The bulletin notes that during the drilling seasons of 2013/14 and 2014/15, the AER and the Alberta Geological Survey ("AGS") observed unexpected persistent patterns of seismic events above the background levels near Fox Creek, Alberta. On January 14 and 23, 2015, the AER and AGS observed events exceeding a local magnitude (ML) of greater than 4.0.

The bulletin provides that, until the AER and AGS can further study the seismic events and their connection to subsurface completion operations, the AER is imposing new seismic monitoring and reporting requirements for hydraulic fracturing in the Duvernay Zone in the Fox Creek area. As part of the monitoring and reporting requirements, licensees in the prescribed area must assess the potential for induced seismicity and develop a response plan to address potential seismic events.

The AER is also imposing a "traffic light" system in the prescribed area, whereby:

(a) Operations can proceed as per the AER's normal requirements if no events are detected;

(b) Observed seismic events of 2.0 ML or greater in the vicinity of operations require a licensee to immediately report the events to the AER and invoke its response plan; and

(c) Observed seismic events of 4.0 ML or greater in the vicinity of operations requires the licensee to cease hydraulic fracturing operations altogether, and will not be permitted to resume operations without the AER's consent.

A map of the area affected by Subsurface Order No. 2 is provided here, on the AER's website.

2015 Orphan Fund Levy (Bulletin 2015-09)
Bulletin – Orphan Fund Levy

The AER announced an orphan fund levy for 2015 in the amount of $15 million, in accordance with the *Oil and Gas Conservation Act*. Each licensee's proportionate share of the levy will be allocated according to:

(a) The Licensee Liability Rating Program contained in Directive 006: *Licensee Liability Rating (LLR) Program and Licence Transfer Process* and Directive 011: *Licensee Liability Rating (LLR) Program – Updated Industry Parameters and Liability Costs*; and

(b) The Oilfield Waste Liability Programs contained in Directive 075: *Oilfield Waste Liability (OWL) Program*.

Bulletin 2015-09 indicated that invoices will be mailed out no later than March 3, 2015, and must be paid no later than April 7, 2015.

ALBERTA UTILITIES COMMISSION

Revision of AUC Rule 027: Specified Penalties for Contravention of Reliability Standards (Bulletin 2015-04)
Bulletin – Rule Revision

The AUC approved amendments to AUC Rule 027: *Specified Penalties for Contravention of Reliability Standards*, effective March 1, 2015. The revised rule can be found here.

ATCO Utilities (ATCO Gas, ATCO Pipelines and ATCO Electric Ltd.) Application for Review of AUC Decision 2014-169 (Decision 3372-D01-2015)
Review Application – Rule 016

ATCO Gas, ATCO Pipelines and ATCO Electric Ltd. (collectively, the "ATCO Utilities") applied for a review of Decision 2014-169: *2010 Evergreen Proceeding for Provision of Information Technology and Customer Care and Billing Services Post 2009 (2010 Evergreen Application)* ("*Decision 2014-169*") pursuant to AUC Rule 016: *Review of Commission Decisions* ("*Rule 016*") (the "Review Application"). *Decision 2014-169* assessed, in part, the prudency of Master Services Agreements that governed the provision of Information Technology services by ATCO I-Tek.

The ATCO Utilities submitted that the hearing panel erred in rendering Decision 2014-169 insofar as:

(a) Failing to consider or give any weight to the totality of the evidence, and ignored uncontroverted evidence without providing reasons for doing so; and

(b) Misapprehended the facts, and committed an error of law, jurisdiction, or both by failing to order production of, potentially, a relevant benchmarking study that it knew to exist at the time of the hearing, but was not tendered by the applicants.

The AUC noted that the ATCO Utilities, in the Review Application, were not alleging that they have recently become apprised of facts that were unknown to them at the time of the original proceeding, nor any other material change that could lead the AUC to materially vary or rescind *Decision 2014-169*.

With respect to the first ground advanced, the AUC rejected the ATCO Utilities' submission that the hearing panel failed to consider the evidence, noting that the hearing panel did assess the evidence, but decided to assign that evidence no weight, which it held was not an error of law. In arriving at this conclusion, the AUC cited *Epcor Generation Inc. v Alberta (Energy and Utilities Board)* for the proposition that "[the tribunal] is free to accept or reject evidence presented by the parties and, as an expert tribunal, it is entitled to use its expertise to arrive at different conclusions than the parties".

With respect to the second ground of review advanced by the ATCO Utilities, the AUC held that the hearing panel did commit an error in stating that no benchmarking study was available. However, the AUC found that the hearing panel's reasons associated with rejecting the benchmarking study was due to the benchmarking consultants' confidentiality concerns, which precluded any examination of such data.

Accordingly, the AUC held that although there was an error of fact, the ATCO Utilities failed to demonstrate a reasonable possibility that could lead the AUC to materially vary or rescind *Decision 2014-169*.

Therefore, the AUC determined that the ATCO Utilities failed to discharge their onus in section 6 of *Rule 016*. For the reasons noted above, the AUC declined to grant the ATCO Utilities' review request in respect of *Decision 2014-169*.

Distribution Performance Based - Regulation Commission - Initiated Review of Assumptions Used in the Accounting Test for Capital Trackers (Decision 3434-D01-2015)
Commission Initiated Review – Test for Capital Tracker - Assumptions

The AUC initiated a proceeding to achieve consistency in the methods and assumptions used by AltaGas Utilities Inc. ("AltaGas"), ATCO Electric Ltd. ("ATCO Electric"), ATCO Gas and Pipelines Ltd. ("ATCO Gas"), EPCOR Distribution & Transmission Inc. ("EPCOR") and FortisAlberta Inc. ("Fortis") in performing accounting test requirements for capital tracker forecast applications. The AUC noted that the scope of the proceeding would examine the possible use of a consistent set of assumptions comprising each company's respective weighted average cost of capital ("WACC") rate, including:

(a) Debt rates;

(a) Return on equity ("ROE") rates; and

(b) Capital structure.

The capital tracker mechanism has three general criteria in order for supplemental capital funding to flow through the "K Factor" under a performance-based regulation ("PBR") plan:

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

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

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

In the PBR mechanism, figures used to determine rate base are escalated by the I-X mechanism, (which is the rate of inflation, less a productivity factor). Programs and projects under a PBR plan are assessed on a project net cost approach to demonstrate that a project is outside the normal course of ongoing operations. The accounting test used to assess the impacts of proposed capital tracker programs occurs in two components. The first component is the revenue provided under the I-X mechanism for a project or program proposed for capital tracker treatment. The second component is the forecasted cost impacts based on actual capital additions for that PBR year.

The AUC noted that all companies had used the WACC assumptions to determine their rates that were approved in their respective general tariff applications in the first component of the accounting test, but noted that some companies used different assumptions for WACC in the second component of the accounting test, such as actual rates or capital tracker forecast amounts.

The AUC held that the purpose of the first component of the accounting test in *Decision 2013-435* was to determine the revenue available through going in rates associated with a project or program under the I-X mechanism.

Therefore, the AUC held that the going-in rates and inputs for WACC in the first component of the accounting test continue to be appropriate.

With respect to the second component of the accounting test, the AUC held that it was strictly based on the company's actual costs and funding requirements with no application of any PBR factors. Therefore, the AUC held it was necessary to update the WACC assumptions for ROE and capital structure in the second component of the accounting test with the most recently approved figures.

However, for matters related to cost of debt and preferred shares, the AUC took a different approach. The AUC held that since the capital tracker amounts are regulated on a cost of service basis, they are calculated outside the I-X mechanism. Accordingly, the AUC found that the I factor would therefore not update the cost of debt for capital tracker amounts.

Therefore the AUC directed the companies to adjust the revenue requirement amount for approved capital tracker costs to reflect the actual cost of embedded debt and actual cost of preferred shares incurred. The AUC also directed companies to use debt forecasts based on the best information available, including updated information from their respective most recent actual debt and preferred share issuances.

With respect to WACC forecast rate true-ups, the AUC held that the purpose of the true-up process was to provide companies with the ability to recover prudently incurred actual costs for capital tracker programs on a more traditional cost of service basis. With this purpose in mind, the AUC held that while companies must use forecast debt using the best information available, any true-ups for these forecasts should match the actual cost of embedded debt incurred by the company in the year for which the project in question was approved.

Therefore, the AUC directed that, in all capital tracker true-up applications, a company's WACC used in the second component of the accounting test must reflect the embedded debt rate based on actual debt issues, and the ROE and capital structure for that year as determined by the AUC in any generic cost of capital proceeding.

The AUC inquired as to whether there were any compelling reasons to use different approaches to calculate WACC rates used in the various components for capital tracker applications. Each of the companies stated that there were no such compelling reasons. Accordingly, the AUC determined that the findings in this decision would apply as a common approach for all companies.

The AUC ordered AltaGas, ATCO Electric, ATCO Gas, EPCOR and Fortis to incorporate the findings of this decision into their compliance filings for their 2013 true-up and 2014-2015 forecast capital tracker applications, as well as all future capital tracker applications.

Maxim Power Corporation 86-MW Cogeneration Power Plant at Milner Site (Decision 3420-D01-2015)
Power Plant Application – Cogeneration

Maxim Power Corporation ("Maxim") applied for approval of an 86-megawatt (MW) cogeneration plant located at its existing HR Milner site, approximately 20 km north of Grande Cache, Alberta (the "M3 Project"). The M3 Project would consist of two 43-MW General Electric LM6000 aero-derivative gas turbine generators with heat recovery steam generators. Milner proposed to cool the M3 Project with water withdrawn from the Smoky River, via a water intake.

Maxim indicated that no changes would be necessary to its conservation and reclamation plans, as Milner proposed to construct the M3 Project entirely within the existing HR Milner site. Therefore, no siting or land use issues would arise for the M3 Project.

Maxim submitted that new federal greenhouse gas regulations require coal-fired generators to meet a performance standard of 420 tonnes of carbon dioxide per gigawatt hour by July 1, 2015. Maxim submitted that its existing coal-fired M1 unit, located at the HR Milner site, would be required to cease its base load operation by

December 31, 2019, and could only operate thereafter as a standby unit. To meet these requirements, Maxim proposed to build the M3 Project, and to reduce the greenhouse gas emissions and increase power output from the HR Milner site by using the steam generated from the M3 Project in the existing M1 unit.

Milner indicated that the construction and operation of the M3 Project would be significantly lower than air emissions from the existing M1 unit for nitrogen oxides, sulphur dioxide and primary particulate matter. Milner noted an increase in carbon monoxide relative to current emissions, but that the concentrations were predicted to be below the Alberta Ambient Air Quality Objectives. Overall, Milner submitted that the M3 Project would have a beneficial effect on regional air quality.

Milner submitted that a noise impact assessment for normal and maximum operating conditions anticipated a predicted sound level contribution of less than one dBA higher than the values for previous noise impact assessments. Milner noted that it modelled impacts at locations 1,500 metres from the M3 Project, despite the nearest residence being approximately 4,000 metres away. The noise impact assessment concluded that predicted cumulative sound levels of the M3 Project would be in compliance with AUC Rule 012: *Noise Control* ("Rule 012") under all operating scenarios.

The AUC found that the impacts of the proposed M3 Project were acceptable and was in the public interest, finding that the environmental impacts would be minimal because the M3 Project would be constructed within the existing site.

The AUC accordingly approved the application on the following conditions:

(a) In the event of a noise complaint, Maxim must conduct a comprehensive sound level survey in accordance with *Rule 012*;

(b) The new water intake will be designed constructed and operated to the satisfaction of Alberta Environment and Sustainable Resource Development and the federal Department of Fisheries and Oceans;

(c) Maxim shall, to the satisfaction of Alberta Environment and Sustainable Resource Development, manage, monitor and report on air emissions, water emissions, and waste generation from plant operations; and

(d) Maxim shall, to the satisfaction of Alberta Environment and Sustainable Resource Development, as applicable, manage, monitor and report the effects of plant operations on ambient air quality, soil, vegetation, surface water, sediment, groundwater, wildlife and fish.

EPCOR Distribution & Transmission Inc. 2013-2014 Transmission Facility Owner Tariff Compliance Filing (Decision 3474-D01-2015)

Compliance Filing – TFO Tariff

Pursuant to AUC *Decision 2014-269*, EPCOR Distribution & Transmission Inc. ("EDTI") filed its 2013-2014 Transmission Facility Owner ("TFO") Tariff compliance filing, requesting approval of its:

(a) Transmission facility revenue requirement for 2013 and 2014;

(b) Transmission rates for 2013 and 2014; and

(c) TFO terms and conditions.

EDTI requested adjusted revenue requirements for 2013 of $75,347,943 and 2014 of $90,105,635. The adjustments represent reductions in revenue requirement of $1.24 million for 2013 and $1.69 million for 2014.

Direction 21 of *Decision 2014-269*, directed EDTI to identify any changes in its physical security requirements from 2012 to 2013 at its Genesee facility, among other filing requirements. Despite the Office of the Utilities Consumer Advocate's ("UCA") objections to EDTI's response to this direction the AUC held that the costs of security for the facility were reasonable, given that such security monitoring is necessary. The AUC also noted that EDTI provided the information requested, and that EDTI explained the basis for such costs sufficiently.

In *Decision 2014-269*, the AUC also directed EDTI to use a three-year average of 2010 to 2012 actual revenue from transmission work for others in its 2013 and 2014 forecasts. The UCA argued that EDTI had not complied with this direction, choosing instead to generate costs based on a combination of historical trends and discussion with parties, and not a strict three-year historical average.

The AUC held that although EDTI did not employ a strict three-year average of 2010 to 2012 actual revenue from transmission work for others, the AUC found that EDTI's methodology reflects the link between costs and revenue from transmission work for others and was therefore a reasonable approach. The AUC approved the forecast revenues of $0.24 million in 2013 and $0.25 million in 2014 for transmission work for others.

The AUC approved the revenue requirements for 2013 and 2014 as filed, the transmission rates requested, and the proposed TFO terms and conditions as filed.

EPCOR Distribution & Transmission Inc. Disposition of Substation Property (Decision 3206-D01-2015)
Disposition of Substation Property Application – Outside Ordinary Course of Business – Public Utilities Act

EPCOR Distribution & Transmission Inc. ("EDTI") requested approval to dispose of a distribution substation and property known as Substation 250 in Edmonton, Alberta (the "Substation"). The Substation consists of the land, transformers, distribution electrical switchgear, protective relaying, and communications and supervisory control and data acquisition equipment (collectively, the "Substation Property"). EDTI requested to dispose of the Substation Property as outside the ordinary course of business, and therefore requested approval pursuant to section 101(2)(d) of the *Public Utilities Act*.

EDTI submitted that the Substation, which was originally built in 1957, was retired from service in 2012, due to the Substations' 5 kV equipment no longer being useful (as this equipment had been replaced with a newer 15 kV circuit), rendering the substation redundant. EDTI explained that the entire Substation was not decommissioned immediately due to timing constraints with higher priority work. EDTI submitted that the equipment was no longer required to provide service to customers and should be removed from rate base. EDTI confirmed that the equipment was still energized, and has not been decommissioned.

EDTI estimated the following:

(a) Decommissioning costs to be approximately $125,000, which would be an operating cost to EDTI and not paid by ratepayers;

(b) That the sale of the property would receive a purchase price of approximately $365,000 to $400,000, conditional upon an environmental assessment; and

(c) The salvage of equipment would net approximately $2,750.

EDTI submitted that all of the Substation Property had been fully depreciated, with the exception of the land and the building itself.

EDTI proposed to remove the Substation Property from rate base, resulting in reductions of $1,492 for the remaining book value of the land, and $103,092 for the remaining book value of the substation building.

EDTI submitted that there would be no harm to ratepayers, as the service provided would not be impacted. EDTI also noted that there would be a slight savings for ratepayers, since EDTI proposed to pay the transaction costs arising from the disposition, including the $125,000 in operating costs to decommission the Substation.

The AUC indicated that it was concerned about the timing of the disposition process for the Substation Property, given that the five-kilovolt equipment ceased to provide service in 2012, and the application to dispose of the assets was brought in May 2014. The AUC held that once an asset is no longer required for utility purposes, the utility must act expeditiously in taking prudent steps to salvage or to sell the asset in order to mitigate further depreciation costs to the ratepayers. Failure to do so may result in the disallowance of depreciation costs.

The AUC, however, accepted EDTI's explanation for not immediately decommissioning the assets given the circumstances, noting that the delay did not impact the quality or quantity of service, and the impact of depreciation costs were minimal.

The Consumers' Coalition of Alberta ("CCA") submitted that the disposition should be considered as part of the ordinary course of business, due to the lack of materiality in the transaction at approximately $400,000. The CCA argued that a pro-rata adjustment of materiality threshold set down by the AUC in *Decision 2011-450* should apply.

With respect to the materiality of the proposed transaction, the AUC determined that no materiality threshold should apply in this particular application, given the range of transaction values previously approved as outside the ordinary course of business. The AUC also held that the infrequency of transactions such as the sale of the Substation Property further suggested that the proposed disposition is outside the ordinary course of business.

Having found that the proposed transaction was outside the normal course of business, and required the AUC's consent, the AUC turned to the "no harm" test in assessing whether the disposition will negatively affect service quality or quantity, or rates.

The AUC held that the transaction would not adversely affect rates or the quantity or quality of service, noting that the Substation Property was no longer required for service, and therefore would not have an impact on service. The AUC also held that the impact on the revenue requirement associated with the substation assets would be negligible, and therefore would not create any adverse financial impact.

Therefore, the AUC approved the proposed sale of the Substation Property and directed EDTI to:

(a) File the details of the disposition, including net proceeds from the sale of the Substation Property in its next revenue requirement application; and

(b) Remove the Substation Property from its distribution rate base at the end of its performance-based regulation term in 2018.

Various AUC NID and Facility Applications

Needs Identification Document - Facility Application

The AUC approved the following need applications and related facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary complies with *AUC Rule 012*;
- There was no evidence that the AESO need assessment is technically deficient;
- The facility proposed satisfies the need identified;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*;
- Considering the social, economic and environmental impacts, the project is in the public interest; and
- The project is in accordance with any applicable regional plan.

Decision	Party	Application
3570-D01-2015	Alberta Electric System Operator	Strachan 263S Substation Upgrade NID
	AltaLink Management Ltd.	Strachan 263S Substation Upgrade Facility Application
3453-D01-2015	Alberta Electric System Operator	Cochrane 291S Substation NID
	AltaLink Management Ltd.	Cochrane 291S Substation Alteration Facility Application
3573-D01-2015	Alberta Electric System Operator	Scotford 409S Substation Upgrade NID
	AltaLink Management Ltd.	Scotford 409S Substation Upgrade Facility Application
3527-D01-2015	Alberta Electric System Operator	Norcen 812S Substation Upgrade NID
	ATCO Electric Ltd.	Norcen 812S Substation Upgrade Facility Application
3431-D01-2015	Alberta Electric System Operator	Hayter 277S Substation Upgrade NID
	AltaLink Management Ltd.	Hayter 277S Substation Upgrade Facility Application
3476-D01-2015	Alberta Electric System Operator	Yeo 2015S Substation NID
	ATCO Electric Ltd.	Yeo Substation Project Facility Application

The AUC approved the following facility applications upon finding that:

- The public consultation complies with *AUC Rule 007*;
- The noise impact assessment summary will comply with *AUC Rule 012*;
- Technical, siting and environmental aspects of the facilities comply with *AUC Rule 007*; and
- Considering the social, economic and environmental impacts, the project is in the public interest.

Decision	Party	Application
3498-D01-2015	City of Medicine Hat	Construct and operate 43-MW Gas-fired Generator and Two-MW Diesel Black Start Unit
3194-D01-2015	Imperial Oil Limited	43-MW Cogeneration Power Plant at Strathcona Refinery
3569-D01-2015	AltaLink Management Ltd.	Calder 9037R Radio Site Telecommunications Tower Replacement
3480-D01-2015	AltaLink Management Ltd.	High River 65S Substation Alteration
3572-D01-2015	TransCanada Energy Ltd.	Bear Creek Power Plant Alteration
3478-D01-2015	EPCOR Distribution & Transmission Inc.	Victoria E511S Substation Expansion
3604-D01-2015	AltaLink Management Ltd.	Wetaskiwin 40S Substation Alteration
3571-D01-2015	AltaLink Management Ltd.	Deerland 13S Substation Telecommunications Upgrade

NATIONAL ENERGY BOARD

Enbridge Pipelines Inc. - Edmonton to Hardisty Pipeline Project - Certificate OC-062 - Application for a Variance of the Certificate to Allow for Modifications to the Project Specifications (Safety and Environmental Compliance – 23 January 2015)
Certificate Variance Application

The NEB, by way of letter decision, allowed a variance application by Enbridge Pipelines Inc ("Enbridge") to modify the specifications for its Edmonton to Hardisty Pipeline Project (the "Pipeline"). The NEB held that the modifications to the wall thickness and maximum operating pressure of the Pipeline were in the public interest. However, the NEB noted that approval from the Governor in Council was still required for the approval to take effect.

The NEB also noted that, while it did accept the engineering basis for the changes sought, the timing of the application raised compliance concerns. Specifically, Enbridge acknowledged its non-compliance with condition 2 of Certificate OC-62, as the Pipeline was not being constructed in accordance with the specifications, standards and other information in the application for the Pipeline, with respect to the wall thickness and maximum operating pressure. The NEB noted that the compliance aspect of the matter had been referred for a separate review.

Enbridge Pipelines Inc. Line 9B Reversal and Line 9 Capacity Expansion Project (Letter and Order MO-001-2015)
Valve Placement – Watercourse Crossing

By letter decision, the NEB released Order MO-001-2015 (the "2015 Order") related to Enbridge Pipelines Inc.'s ("Enbridge") filings on conditions 16 and 18 in Order XO-E101-003-2014 (the "2014 Order").

Condition 16 of the 2014 Order related to valve placement by Enbridge on Line 9 and 9B. While the NEB noted that increased valve spacing can be an effective tool to minimize the consequences of pipeline failures, it also held that sectionalizing valves does not always lessen the size of a given release due to increases in pump capacity. The NEB also noted that valve placement can alter the risk to the environment, especially near water crossings or other environmentally sensitive areas. As a result, the NEB imposed additional prevention measures to address the impact of increased pump capacity.

Enbridge's filing proposed to add several additional valves using its Intelligent Valve Placement ("IVP") methodology. Enbridge submitted that it took a conservative approach in its IVP methodology, by treating all water crossings equally in terms of impacts and valve placement.

The NEB found the IVP methodology to be reasonable, noting the large number of high consequence areas near Line 9B. As a result, the NEB approved Enbridge's submission on condition 16 of the 2014 Order, but noted that it would impose ongoing analysis and assessment requirements for valve placement throughout the lifecycle of the pipeline.

The NEB imposed condition 18 of the 2014 Order for the purpose of establishing a new baseline condition assessment of major watercourse crossings through the submission of a Watercourse Crossing Management Plan ("WCMP"). Enbridge submitted an updated WCMP which, the NEB held, demonstrated how Enbridge will proactively manage numerous watercourse crossings along the existing lines.

The NEB held that Enbridge met the requirements of condition 18 of the 2014 Order, and held that the information gathered in the course of the update of the WCMP can inform the analysis used under the IVP methodology.

The NEB noted that prior to operating the pipeline, Enbridge must still apply for and be granted leave to open, and must comply with all post construction conditions set out in the 2014 Order.

The NEB therefore issued the 2015 Order requiring further review and analysis of water crossings, valve locations and associated risks in accordance with Enbridge's IVP methodology.