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Assessment of AESO Transmission Cost of Service Analysis

Prepared for:

Alberta Electric System Operator (AESO)

NERA

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EXECUTIVE SUMMARY

The Alberta Electric System Operator (AESO) is in the process of updating its cost-of-service methods and transmission rate structure to reflect the current industry structure and evolving system conditions. In carrying out its cost-of-service and transmission rate design responsibilities, AESO sub-functionalizes and classifies the transmission revenue requirements of the four Transmission Facility Owners (TFOs) plus AESO, and suggests the billing factors that should be used to recover these costs. Some aspects of AESO's analysis have proved controversial. Of particular concern is AESO's finding that peak loadings on the various transmission lines in the Alberta system are not well correlated with system peak demand and, therefore, that coincident peak billing is not appropriate for the Alberta system.

AESO retained NERA to review the latest AESO transmission cost-of-service studies, presented in the reports *Wires Only-Cost Causation Study*¹ of January 25, 2005 ("AESO Study") and *2006 Transmission Cost Causation Update* of September 15, 2006 ("AESO Update"), to analyze stakeholder comments on particular issues in those studies, and to provide recommendations on Bulk and Local transmission wires cost sub-functionalization, classification and cost recovery. NERA was also asked to provide information on methods used to functionalize, classify and recover transmission wires costs in other jurisdictions, including regions with transmission systems similar to those in Alberta. (See the Appendix for a summary of methods used elsewhere.)

Based on our review of the materials provided by AESO and discussions with AESO staff, we identified six key questions regarding functionalization, classification and recovery of Bulk wires costs. Our answers for each question are summarized below. On the whole we find AESO's proposed approach reasonable, although we do offer suggestions for a few refinements.

1. Should the factors affecting the original investment or the nature of current use of the transmission facilities be used as the basis for sub-functionalization, classification and rate design?

The EUB considers the provision of appropriate price signals that reflect all costs and benefits of the service to be a key objective of AESO's transmission rates. These price signals influence current and future electricity use by consumers. We are not aware of any North American jurisdiction that functionalizes or subfunctionalizes transmission costs based on the circumstances at the time the investment was made, when the current function of the equipment has changed. We are also not aware of any jurisdiction in North America that classifies and allocates costs based on the factors that affected historical system

¹ Both studies were done by PS Technologies Inc. on behalf of AESO.

expansion decisions. For example, it would not be reasonable to charge for transmission service on the basis of winter coincident peaks in a system that has shifted from winter peaking to summer peaking. Even embedded cost of service studies and rate designs must reflect current (and near-term) system conditions. We believe that AESO's functionalization, classification and rate design methods do that.

2. Is there sufficient rationale for separating Bulk and Local wires costs for purposes of rate design?

Standard industry practice is to combine bulk and local costs unless there are separate rates for customers who use only the Bulk system. Most AESO customers use both the Bulk and Local systems² and AESO's charges do not differentiate by interconnection voltage. Underlying the AESO proposal to combine Bulk and Local costs is the assumption that bulk facilities tend to evolve into local facilities over time and in areas experiencing load growth. Any line drawn between the two will be highly uncertain, which is just what the study indicates. Furthermore, AESO's detailed analysis suggests that although Bulk and Local planning differs in many respects, for both the Bulk and Local systems planning is fundamentally a matter of providing sufficient capacity to accommodate loads under adverse conditions. A variety of factors contribute to "Maximum Stress" on both bulk and local line segments, and the timing of maximum stress can vary widely. In addition, AESO's classification of Bulk and Local costs results in very similar energy- and demand-related percentages. Finally, with the proposed non-coincident peak (NCP) charging mechanism (discussed below) for Bulk demand-related costs, the Bulk and Local costs could logically be merged in the cost-of-service analysis and rate structure.

3. Is the use of a minimum system approach to identify demand and energy components of Bulk lines appropriate?

Classification of a portion of transmission costs to energy is a standard industry practice, although less common than treating all transmission as demand-related.³ AESO used a minimum system approach to identify the portion of Bulk costs incurred without regard to losses (the demand-related portion), with the remaining costs assumed to be incurred to reduce losses (the energy-related portion). We believe that the minimum system analysis of the Bulk costs is a reasonable way to identify the share of costs spent to reduce losses. This

² Some AESO customers are connected at 240 kV, which implies use of the bulk system only. However, these connections usually reflect system expansion considerations rather than customer load requirements. Furthermore, the AESO Study found that some 240-kV facilities are part of the Local system.

³ In some cases selected transmission lines are *functionalized* to generation (e.g., because they connect a remote generator to the main transmission grid) and are therefore classified to energy and demand with other generation costs.

approach is consistent with one of the rationales for energy classification mentioned in the NARUC Cost Allocation Manual.⁴

4. Is the partial recovery of demand-related Bulk costs on an energy basis appropriate?

In the rate design step, AESO made a further adjustment to the classification of Bulk costs. The AESO Update identified the time of each Bulk line's individual peak and the Alberta Internal Load (AIL) at that time, and divided that AIL by the annual peak AIL. It then calculated a length-weighted average of these ratios across all Bulk lines. The resulting percentage (about 80 percent) was multiplied by the demand-related share of Bulk costs to yield the amount to be recovered on a demand basis. AESO's stated reason for shifting some demand-related Bulk costs to the energy rate component is that the Bulk system is built with diversity of customer NCPs in mind. We do not think that this justifies the adjustment. The diversity of customer NCPs is taken into account when the demand charges are calculated; the Bulk costs defined as demand-related are divided by the NCP billing determinants, which reflect diversity.

The AESO Update established that the timing of the AIL peak is not what drives the need for transmission capacity. Therefore, using AIL ratios to adjust the amount of revenue to be recovered on a demand-related basis is not consistent with AESO's conceptual approach. Furthermore, this adjustment introduces a distortion in rate design compared to the results of the classification step. If AESO believes that some costs classified to demand should be recovered on an energy basis, it should specify the reason, and develop a non-arbitrary method for doing so in the allocation/rate design step. For example, a version of the average and excess (A&E) method could be used to separate demand-related Bulk costs into amounts to be recovered on an energy basis and amounts to be recovered on some measure of NCP.⁵

5. Is Customer NCP an appropriate cost recovery method for demand-related Bulk system costs?

Given (1) the diverse loading patterns on AESO's Bulk system (both in terms of location and timing), (2) the difficulty of predicting when and where system stress will appear, and (3) the requirement that rates not be location-differentiated, Alberta transmission system users should face incentives to carefully control loads in all hours. AESO's proposal to recover a significant portion of demand-related Bulk system costs on the basis of NCP will provide a very strong incentive to engage in this beneficial behaviour whenever there is any

⁴ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (Jan 1992).

⁵ The standard A&E demand allocator is the difference between NCP and average energy. Because this ratio might be difficult to use as a billing factor, some modification would probably be required.

likelihood of the customer's setting a new peak. In addition, the NCP approach treats each hour as potentially an hour of system stress, which is consistent with system characteristics.

Billing factors based on measures of coincident peak (CP) such as 12 CP or 2 CP, focus customer attention on a few hours of the year, leaving many more system stress hours with essentially a zero price. Billing for demand-related Bulk system costs on an energy-only basis would have a different disadvantage; the cost of using additional transmission service in every hour would be very small.

Use of NCP for demand-related transmission cost allocation is not common, but Nova Scotia Power uses a combination of NCP and CP for this purpose.

6. Does AESO's proposed billing determinant dampen important customer incentives for efficiency that would be present in an alternative approach?

A disadvantage of the AESO proposal to use ratcheted NCP to recover demand-related Bulk system costs is that the incentive to control load will be reduced in hours unlikely to set the billing capacity, although those may be hours when the lines affected by the customer's load are stressed. Other definitions of billing capacity might achieve a better balance of the need for customers to recognize the long-term implications of their loads and the need to give incentives to control loads every month. For example, reducing the 90-percent factor applied to contract capacity and the highest demand in the past 24 months could make NCPs in more months potential factors in the billing capacity calculation.

I. INTRODUCTION

In carrying out its cost-of-service and transmission rate design responsibilities, the Alberta Electric System Operator (AESO) sub-functionalizes and classifies the transmission revenue requirements of the four Transmission Facility Owners (TFOs) plus AESO, and suggests the billing factors that should be used to recover these costs. Some aspects of AESO's analysis have proved controversial. Of particular concern is AESO's finding that peak loadings on the various transmission lines in the Alberta system are not well correlated with system peak demand and, therefore, that coincident peak billing is not appropriate for the Alberta system.

AESO retained NERA to review the latest AESO transmission cost-of-service studies, presented in the reports *Wires Only-Cost Causation Study*⁶ of January 25, 2005 ("AESO Study") and *2006 Transmission Cost Causation Update* of September 15, 2006 ("AESO Update"), to analyze stakeholder comments on particular issues in those studies, and to provide recommendations on Bulk and Local transmission wires cost sub-functionalization, classification and cost recovery. NERA was also asked to provide information on methods used to functionalize, classify and recover transmission wires costs in other jurisdictions, including regions with transmission systems similar to those in Alberta.

This report is structured as follows.

- In Section II, to provide the context for our report, we highlight the objectives of the AESO COS study as well as the overall AESO policy goals.
- In Section III we summarize the methods and steps followed in the AESO Study and AESO Update and identify changes from previous COS methods in Alberta and from the approaches adopted by the Alberta Energy and Utilities Board (EUB) in its August 2006 decision.
- In Section IV we assess the criticisms of the AESO Study by stakeholders and provide recommendations to improve the methods where appropriate. Our assessment includes lessons from experience in other jurisdictions.
- In Section V we summarize our recommendations.

The Appendix to this report summarizes methods adopted for transmission COS studies in selected jurisdictions.

⁶ Both studies were done by PS Technologies Inc. on behalf of AESO.

II. EUB TRANSMISSION RATE OBJECTIVES

In the 2005/06 General Tariff Decision, the EUB agreed with AESO on the following goals of rate design:⁷

- (1) Recovery of the total revenue requirement;
- (2) Provision of appropriate price signals that reflect all costs and benefits, including in comparison with alternative sources of service;
- (3) Fairness, objectivity, and equity that avoids undue discrimination and minimizes inter-customer subsidies;
- (4) Stability and predictability of rates and revenue; and
- (5) Practicality, such that rates are simple, convenient, understandable, acceptable and billable.

In the same decision, the Board stated that the cost causation principle should be given priority:

*“...with regard to the rate design principles discussed above, the Board considers that cost causation must be afforded the most weight in attempting to balance these sometimes competing principles when evaluating a proposed rate design... The principle of rate shock, which can conflict with this cost causation principle, must take a secondary consideration to cost causation in arriving at an appropriate rate design.”*⁸

The AESO Study and AESO Update were intended to identify the cost causation of the several elements of the transmission system. However, in using the study’s results for rate design, AESO recognized that its proposal departed from cost causation. AESO’s specific billing determinant proposals as well as the proposals’ consistency with the methods used in the AESO study are discussed in Sections III and IV below.

⁷ 2005/06 General Tariff Application, page 15.

⁸ 2005/06 General Tariff Application, page 17.

III. SUMMARY OF AESO's COST STUDY AND RATE DESIGN PROPOSALS

The AESO Study sub-functionalizes transmission net plant value in three different categories:

- Bulk System, which includes most 240-kV and all 500-kV lines, plus switching stations and substations;
- Local System, which delivers energy from the bulk system to local points of delivery and includes some 240-kV lines as well as 38/144-kV and 69/72-kV and lower-voltage looped transmission lines; and
- Point of Delivery (POD), which normally provides service to one customer (a distribution utility, or a transmission-connected industrial customer). It includes POD substations and the radial transmission lines exclusively used by those substations. PODs are sized based on the demand of individual customers.

As part of this assignment, NERA was asked to focus on the Bulk System analysis (and, to the extent necessary, the Local System analysis in its differentiation from the Bulk System).

A. Sub-Functionalization Approach

According to AESO,⁹ the distinction between the Bulk and Local systems in AESO's cost-of-service studies and rate structures stems from past EUB directives to differentiate between "deep system" and "shallow system" connection costs because of differences in the way AESO plans these facilities. The higher voltage bulk lines are designed to carry large amounts of power over long distances and are the primary instrument to import and export energy from a region.¹⁰ Local facilities are designed (sized) to meet the loads of several customers.

The AESO Study considered three ways to functionalize wires between Bulk and Local:

- (1) By Voltage Level, with 500-kV and 240-kV investment identified as Bulk, and the rest as Local.
- (2) Using an "Economics" approach, that calculates and graphs the cost of hypothetical lines and associated 25-MW substations of different voltages serving different numbers

⁹ Source: John Martin in an email to Amparo Nieto, September 11, 2006.

¹⁰ See Wires Only-Cost Causation Study, January 25 2005. Section 4.1.

of PODs. Two cross-over points are used to divide 240-kV Bulk from Local, and 138-kV Bulk from Local.^{11,12}

- (3) Using the MW-km method. This method weights by 2004/2005 winter peak hour loadings the length of almost 900 line segments covering the four transmission voltages: 69/72-kV, 138/144-kV, 240-kV, and 500-kV. The method then uses expert judgment to identify a threshold MW-km that separates the Bulk and Local functions. Lines of 138-kV and below were considered to be providing Local function, and all 500-kV lines were considered Bulk. The 240-kV lines were split between Bulk and Local function, using 3000 MW-kM as the threshold.

The AESO Study recommended averaging the results of the three sub-functionalization methods. Following this approach, the Bulk System costs represent about 42 percent of the total wires costs, Local System costs represents 17 percent, and POD costs about 41 percent.

B. Classification of Bulk and Local Costs and Billing Method

Prior to restructuring of the Alberta electricity industry in 1996, transmission costs were entirely classified as demand-related. In the AESO Study, Bulk and Local transmission were classified on a “minimum system” basis. The demand-related costs were defined as those associated with a hypothetical line with a minimum sized conductor. The energy-related costs were defined as those associated with upgrading the line to an optimal configuration that minimizes costs, including losses. A similar calculation was done for bulk substations using basic and high efficiency transformers. The preliminary classification resulting from this analysis in the AESO Study was as follows:

- Bulk costs: 81.5 percent classified as demand-related. The remaining 18.5 percent classified as energy-related.
- Local costs: 82.5 percent demand-related, 17.5 percent energy-related.

The allocation/recovery of Bulk demand-related costs proposed in the AESO Study and AESO Update differs from previous COS studies in Alberta, in part because the single transmission load rate class makes allocation and rate design a single step. Prior to 1996, this was a two-step process; all transmission (including Bulk) costs were allocated to **rate classes** (not customers)

¹¹ The two smaller utilities lacked the data to functionalize on this basis.

¹² The rationale for this approach is that, over time, higher voltage higher capacity facilities are added to the system to perform the Bulk function, with the components that previously served that function now serving the Local function. As there are fringe areas where lower voltage facilities continue to provide the Bulk supply function, there is not one voltage that provides pure Bulk transmission, with all lower voltage lines performing the Local transmission function.

using coincident peak (CP)- based factors,¹³ and billed to customers based on NCP and energy billing determinants. The 2006 DTS rate charges for demand-related use of the Bulk system on a monthly CP basis.¹⁴

The AESO Study and AESO Update explained that transmission demand-related costs are associated with the “Coincident Load at the time of Maximum Stress” (CLMS), and provided evidence that CLMS is not closely related to the peak Alberta Internal Load (AIL).¹⁵ Stress can result from violating (a) thermal capacity, (b) voltage, or/and (c) stability limits. Maximum stress is driven by a number of variables, including location of generation, dispatch, imports and exports. Because the timing of peak stress varies at different points in the system and cannot be accurately predicted, the AESO Report stated that CLMS is not a practical billing determinant, and proposed that charges should instead be based on individual customer non-coincident peak demand (NCP).¹⁶

In conjunction with the proposed switch to NCP billing, AESO proposed redefining a portion of the demand-related Bulk cost as energy-related. AESO computed the ratio of AIL in the hour of peak load on a given Bulk line to annual AIL peak, weighted these ratios by line length, and averaged the weighted ratios over all Bulk lines. This factor (approximately 80 percent), was multiplied by the share of transmission cost originally defined as demand related to determine the share of costs to be recovered on a demand basis.

AESO's rationale for the reduction in Bulk system demand charges (and corresponding increase in Bulk system energy charges) resulting from this adjustment is to reflect the diversity of POD loads and the lack of coincidence of individual POD loads with maximum stress on the Bulk system components.

¹³ Either 1-Coincident Peak (CP), or 3-Winter-CPs / 9-Non-Winter CPs. The latter method weights the average of the three Winter CPs equally with the average of the nine Non-Winter CPs.

¹⁴ EUB Order U2005-464 (December 20, 2005), effective January 1, 2006.

¹⁵ The original report looked at two paths (NOC and SOK) and found the CLMS falling in the early morning of July for NOC and early morning of September for SOK, times that did not coincide with AIL peak. The AESO Update provided detailed qualitative and quantitative results on correlation between bulk transmission loads and the Alberta Internal Load (AIL). The qualitative results consist of information on the constraining factors and timing for 12 crucial paths or transmission facilities, collected in interviews with transmission planners. They indicated that only some Northern Alberta transmission additions were driven by conditions that coincided with peak AIL. The quantitative results consist of correlations between loads on 79 240-kV lines and the AIL. This analysis found that about one third of the lines were negatively correlated with AIL, and correlation of the remainder fell between 0.1 and 0.4. The results generally support the position that the peak AIL is not a cost driver for bulk transmission.

¹⁶ Greatest of the highest 15-minute metered demand in the billing period, 90 percent of contract capacity, or 90 percent of the peak demand in the prior 24 months.

SUMMARY OF AESO's COST STUDY AND RATE DESIGN PROPOSALS

The EUB agreed with AESO's proposal to moderate the demand-related portion of the Bulk System rates (compared to using the results of the minimum system analysis). As a result, the classification factors for Bulk costs in the 2007 DRAFT GTA (July 2006) were: 66 percent demand-related (\$95.4 million), 34 percent energy-related.

IV. ASSESSMENT OF AESO COSTING METHODS AND RATE PROPOSALS

We identified six key issues regarding functionalization, classification and recovery of Bulk wires costs: (1) Should the factors affecting the original investment or the nature of current use of the transmission facilities be used as the basis for sub-functionalization, classification and rate design? (2) Is there sufficient rationale for separating Bulk and Local wires costs for purposes of rate design? (3) Is the use of a minimum system approach to identify demand and energy components of Bulk lines appropriate? (4) Is the partial recovery of demand-related Bulk costs on an energy basis appropriate? (5) Is customer NCP an appropriate cost recovery method for demand-related Bulk system costs? (6) Does AESO's proposed billing determinant dampen important customer incentives for efficiency that would be present in an alternative approach?

In this section we summarize industry practice regarding the key issues, assess related main stakeholder criticisms of the AESO Study and AESO Update, and provide our views of, and suggestions for refinements to, the methods used.

A. Industry Practice

To identify how these key issues are addressed elsewhere in the industry, we reviewed the National Association of Regulatory Utility Commissioners (NARUC) Electric Utility Cost Allocation Manual (Manual), policies of the US Federal Energy Regulatory Commission (FERC), and practice at selected utilities and Independent System Operators (ISOs) in North America.

1. NARUC Manual

a. Functionalization

According to the most recent edition (1992) of the NARUC Manual,¹⁷ there are two functionalization methods for transmission. The first recognizes only one cost group. Radial transmission lines are normally excluded from the transmission function since they serve only specific customers. In some cases however, radial lines can be included when they are a short-term strategy to maximize system efficiency by phasing-in expansions.

The second method sub-functionalizes transmission, differentiating among:

¹⁷ National Association of Regulatory Utility Commissioners, *Electric Utility Cost Allocation Manual* (Jan 1992).

- Backbone and inter-tie facilities.
- Generation step-up substations, which are an extension of generation plants and are typically treated accordingly, particularly to avoid charging wheeling customers for generation plant they do not use.
- Subtransmission used to transfer energy from the backbone system to the distribution system. Cost responsibility is usually assigned only to those loads directly served at that voltage level and the distribution loads fed through it.
- Radial facilities or facilities not networked with other transmission facilities. Costs may be directly allocated to directly connected customers.

The purpose of this sub-functionalization is primarily to avoid charging customers connected at high voltages for the costs of facilities at lower voltages.

b. Classification

The NARUC manual indicates that transmission costs are typically classified in two categories: demand-related and energy-related. While transmission costs are generally considered fixed costs that do not vary with energy transmitted, and are therefore 100-percent demand-related, “to the extent that transmission investment enables a utility to avoid line losses, some portion of transmission may be classified as energy-related” and allocated to classes on the basis of annual energy use.¹⁸ This language suggests that it is appropriate to employ current use of the system, rather than historical factors, to make the determination regarding the energy- and demand-related portions of transmission investment.

Another view noted in the NARUC manual is that, since transmission is designed with redundancy to provide reliable service even under adverse conditions, there is an energy-delivery system component, allocable on an energy basis, and a reliability component, allocable on some measure of demand. This method is not in common usage.¹⁹

c. Rate Design

According to the NARUC manual, demand-related transmission costs that are not directly assigned can be allocated to classes (and/or recovered from customers) using one of the following methods or a combination of them:

- Single CP assumes that the single highest peak drives power supply cost decisions.

¹⁸ NARUC Manual, p. 21.

¹⁹ NARUC Manual, p. 75.

- Average seasonal CP is used when utilities experience comparable peak demands during several months of the peak season.
- 12 CP (average contribution to the 12 monthly system peaks) recognizes the idea that utilities install transmission facilities to keep a constant level of reliability throughout the year.
- NCP recognizes the maximum demand placed during the year by all customers individually.
- Average and Excess divides transmission costs into energy and demand components based on the system load factor and recovers the energy-related costs on the basis of average annual energy use and the demand-related portion on the basis of the difference between customers' annual NCP and average energy use. This method is typically used for transmission when it is also applied to generation costs.

2. FERC Policy

FERC's standard method is to classify all fixed transmission costs as demand-related and allocate using 12 CP because it believes that the majority of utilities plan their transmission systems to meet their twelve monthly peaks. However, FERC has indicated in a number of filings that utilities could use another method if they demonstrate that it reflects their transmission system planning.²⁰

3. Cost-of-Service Methods in North America

NERA has reviewed embedded transmission COS studies in jurisdictions in North America to determine how they deal with the key issues addressed in this report.

a. Sub-functionalization of Transmission

In our survey we did not find any jurisdiction that splits Bulk and looped Local transmission costs. FERC requires US utilities to define facilities as transmission or local distribution on a case by case basis,²¹ but in AESO's case, the separation of distribution from transmission is not an issue.

²⁰ FERC Docket Nos. RM95-8-001 and RM94-7-002; Order No. 888-A.

²¹ Order 888 outlined several indicators to help determining whether particular facilities are transmission or distribution: (1) Local distribution facilities are normally in close proximity to retail customers; (2) Local distribution facilities are primarily radial in character; (3) Power flows into local distribution systems; it rarely, if ever, flows out; (4) When power enters a local distribution system, it is not transported on to some other market; (5) Power entering a local distribution system is consumed in a comparatively restricted geographical

b. Classification and Recovery of Transmission Costs

In most of the North American utilities surveyed, transmission is classified entirely as demand-related and allocated using 12 CP (FERC's standard method) or another measure of coincident peak. However, we did find variations on this method. In those cases, the cost-of-service methods and rate designs are not exclusively focused on the historical factors driving transmission investment but rather on the current use of the system. Examples of utilities or independent system operators that classify some transmission as energy-related are described below.

- Nova Scotia Power (NSP) – NSP has indicated that its system use is somewhat different from typical transmission networks, as flows on the backbone transmission system do not vary in direct proportion to peak load. In the embedded cost for its native load, transmission costs were classified using system load factor, which resulted in about 62 percent of the costs being treated as energy-related and 38 percent as demand-related.²² The demand-related costs were then allocated using the average of three CPs (December, January and February). For purposes of setting NSP's wholesale transmission tariff, however, transmission is classified as demand-related and recovered on the basis of monthly NCP demand. The use of NCP is justified on the basis that NSP's backbone transmission load does not vary in direct proportion to peak load.²³
- Puget Sound Energy – At Puget Sound Energy the costs of bulk and sub-transmission, as well as transmission used to integrate remote generation, are functionalized, classified, and allocated in the same manner as production costs – using the peak credit method. This method estimates the demand-related portion of transmission plant as the cost of a proxy generation capacity resource and treats the remaining share as energy-related. The demand-related costs are allocated based on class contribution to the load during the system's 200 coincident peak hours.
- PacifiCorp classifies transmission as 75 percent demand-related and 25 energy-related, following the same classification as generation. The demand-related portion is allocated on a 12-CP basis. According to the utility, demand costs are allocated in this manner because capacity is important to the company for meeting peak loads, load following and plant maintenance each month.

area; (6)Meters are based at the transmission/local distribution interface to measure flows into the local distribution system; (7)Local distribution facilities are of reduced voltage. Note that these rules for functionalization apply to current use of facilities, not to historical factors.

²² Environmental costs are extracted up front and classified directly to energy on a 100% basis.

²³ March 24, 2005 technical response to IR-5 referenced in the direct Testimony of Robert M. Fagan before the Nova Scotia Utility and Review Board, April 5, 2005.

- The New York Independent System Operator charges a Transmission Service Cost (TSC) rate to serve load within the New York control area. The TSC is intended to recover the total transmission owners' revenue requirement classified as energy and allocated on the basis of annual MWh.
- The California Independent System Operator classifies transmission costs as energy and allocates these costs to transmission users on the basis of energy taken off the grid.

B. NERA Assessment

1. Sub-Functionalization of Transmission Costs

According to AESO, the split between Bulk and Local costs in Alberta was driven by the 'deep' versus 'shallow' distinction in the calculation of connection costs. Underlying the study is the assumption that Bulk facilities tend to evolve into Local facilities over time and in areas experiencing load growth. Any separation between Bulk and Local transmission will naturally be uncertain, which is just what the study indicates. AESO's transmission planners view the Bulk and Local system differently; i.e., stability problems do not occur on the Local System but they do on the Bulk System. Furthermore, the AESO Study identified the differences in planning for the two categories. However, AESO's detailed analysis suggests that planning for both Bulk and Local system additions is fundamentally a matter of providing sufficient capacity to accommodate loads under adverse conditions. In both cases a variety of factors contribute to "Maximum Stress" on a line segment, and the timing of maximum stress can vary widely. In addition, AESO's classification of both Bulk and Local costs results in very similar energy- and demand-related percentages. Most AESO customers use both the Bulk and Local systems²⁴ and AESO's charges do not differentiate by interconnection voltage. Finally, our endorsement of the proposed NCP charging mechanism for both Bulk and Local demand-related costs (discussed below) means that the Bulk and Local costs could logically be merged in the cost-of-service analysis and rate structure.

2. Classification of Bulk-Power Costs

AESO used a minimum system approach to identify the portion of Bulk costs incurred without regard to losses (the demand-related portion), with the remaining actual costs assumed to be incurred to reduce losses (the energy-related portion). AESO explained that it does take losses into consideration in planning and constructing the Alberta system. Moreover the Public Utility Board agrees with this, as noted in the 2005 EUB Decision which states that "... embedded

²⁴ Some AESO customers are connected at 240 kV, which implies use of the bulk system only. However, these connections usually reflect system expansion considerations rather than customer load requirements. Furthermore, the AESO Study shows that some 240-kV facilities are part of the Local system.

costs are incurred to optimize losses, and...the board is prepared to accept that some portion of embedded wires costs are energy related.”²⁵ The fact that transmission investment is lumpy and that there may be excess capacity from time-to-time does not distort the results of the minimum system analysis, because the analysis used a hypothetical facility without excess capacity. We believe that the minimum system analysis of the Bulk costs is a reasonable way to identify the share of costs spent to reduce losses.²⁶

As described above, in the rate design stage AESO made a further adjustment to the classification of Bulk costs. The AESO Update identified the time of each Bulk line’s individual peak and the Alberta Internal Load (AIL) at that time, and divided that AIL by the annual peak AIL. It then calculated a length-weighted average of these ratios across all Bulk lines. The resulting percentage (about 80 percent) was multiplied by the demand-related share of Bulk costs to yield the adjusted share to be recovered in demand charges. AESO’s stated reason for the adjustment – that the Bulk system is built with diversity of customer NCPs in mind – does not justify the adjustment. The diversity of customer NCPs is taken into account when the demand charges are calculated; the defined demand-related Bulk costs are divided by the NCP billing determinants, which reflect diversity. In addition, the AESO Update established that the timing of coincident AIL peak is not what drives the need for transmission capacity. Therefore, using these AIL ratios to adjust the demand-related costs for purposes of rate design is not consistent with AESO’s conceptual approach. This adjustment introduces a distortion in rate design compared to the results from the classification step. The minimum system approach applies the same demand/energy factors to every asset in the system, regardless of whether the asset was built to meet demand or energy needs. As mentioned above, we believe this is a reasonable approach. If AESO believes that this classification approach results in some costs classified to demand that should be recovered on an energy basis, it should explicitly identify the reason, and develop a non-arbitrary method for doing so in the allocation/rate design step.

For example, AESO could apply a version of the average and excess (A&E) method to the Bulk costs classified to demand. This approach would use the system load factor to identify the percentage of demand-related Bulk costs to be recovered on an energy basis, and one minus the system load factor to determine the share to be recovered on the basis of some measure of NCP.²⁷

²⁵ EUB Decision 2005-096 (August 28, 2005), pages 23 and 24.

²⁶ There may be other energy-related transmission investment, such as lines built primarily (or made larger) to import cheap energy or facilitate exports. However, such facilities are a substitute for generation and, in the context of AESO’s cost-of-service and rate design, their energy-related aspects should probably be ignored.

²⁷ The standard A&E demand allocator is the difference between NCP and average energy. Because this ratio might be difficult to use as a billing factor, some modification would probably be required.

3. Locational Differences and Reflection of Historical or Current Cost Causation

Expansion of the Alberta electricity transmission system is driven by different factors and load growth at different times of the day or year, depending on location. In southern Alberta, expansion has been driven primarily by thermal capacity constraints in the summer. In the future, transmission expansion in the south will be driven by the addition of wind generation. Some transmission expansion in northern Alberta is driven by load-related concerns that occur in the winter and are coincident with the Alberta peak load.

A transmission cost study could reflect these locational differences. A geographic probability of peak analysis would estimate the relative probability that an increment of load in a given hour and in a given part of the system would contribute to the need for investment in that region. However, given legislative restrictions on locational transmission charges,²⁸ the limited usability of such a probability analysis would probably not justify the effort.

One stakeholder believes that, although current stress on the transmission system occur in hours other than the hours of peak AIL and can occur at different times in different parts of the system, Bulk transmission costs should be classified and allocated on the basis of the factors that drove system expansion in the past, i.e., the system peak demand. One response to this point is cited in the EUB 2005 Decision: “However, Mr. Reimer described (T0834) the difficulty in recreating history to determine precisely what embedded costs would have been associated with energy efficiency. Given these challenges, a simplified approach was taken in the TCCS...”²⁹ This indicates that basing the study on the history of transmission expansion planning, is impractical.

More important is the effect that such a backward-looking approach would have on price signals. The EUB considers the provision of appropriate price signals reflecting all costs and benefits of the service to be a key objective of AESO’s transmission rates. We are not aware of any North American jurisdiction that functionalizes or subfunctionalizes transmission costs based on the circumstances at the time the investment was made, when the current function of the equipment has changed. We are also not aware of any jurisdiction in North America that classifies and allocates costs based on the factors that affected historical system expansion decisions without regard to the current use of the system. Would it be reasonable to charge for transmission service on the basis of winter coincident peaks in a system that has shifted from

²⁸ In Alberta, the primary arrangements to solve transmission congestion (other than building more wires) are various forms of “Transmission Must Run” (TMR) contracts. There are also constraints management protocols which may also be used to limit loads to contract levels in constrained areas. The only locational differences in market prices are the location-specific loss factors attributable to generators. Any other locational differences are prevented by legislation.

²⁹ EUB Decision 2005-096 (August 28, 2005), pages 23.

winter peaking to summer peaking? Clearly, it would not. Even an embedded cost of service study and rate design must reflect current (and near-term) system conditions. We believe that AESO's classification and allocation methods do that.

4. Implications of Using NCP Approach versus CP methods

One stakeholder has argued that use of NCP for recovery of Bulk demand-related costs will remove any customer incentives for "beneficial behaviour." The stakeholder also complained that AESO did not provide any statistical support that use of NCP would more accurately assign the costs of bulk transmission line costs to customers than would the 12-CP method or a broader definition of an on-peak allocation method.

Given (1) the diverse loading patterns on AESO's Bulk system, both in terms of location and timing, (2) the difficulty of predicting when and where system stress will appear, and (3) the requirement for rates that are not location-differentiated, Alberta transmission system users should face incentives to carefully control loads in all hours. AESO's proposal to recover demand-related Bulk system costs on the basis of NCP will provide a very strong incentive to engage in this beneficial behaviour whenever there is any likelihood of the customer's setting a new peak. In addition, the NCP approach treats each hour as potentially an hour of system stress, which is consistent with system characteristics.

Billing factors such as 12 CP (or other measures of coincident demand) focus customer attention on a few hours of the year, leaving many more system stress hours with essentially a zero price. Billing for demand-related Bulk system costs on an energy-only basis would have a different disadvantage; the cost of using additional transmission service in every hour would be very small.

A disadvantage of the AESO proposal is that the incentive to control load will be reduced in hours unlikely to set the customer's billing capacity, although those may be hours when the lines serving the customer are stressed. We understand that the rationale for using 90 percent of contract capacity in the calculation of billing capacity reflects the need to make long-term investments based on expected customer loads. However, other definitions of billing capacity might achieve a better balance of the need for customers to recognize the long-term implications of their loads and the need to give incentives to control loads every month. For example, reducing the 90-percent factor applied to contract capacity and the highest demand in the past 24 months could make NCPs in more months potential factors in the billing capacity calculation. Choosing the appropriate definition of billing capacity is a balancing act that requires consideration of many factors, including (1) the utility's ability to bear (and compensation for bearing) risk of revenue undercollection, (2) the degree to which revenue shortfalls can be subsequently passed on to customers, (3) the need to send efficient price

signals to customers, and (4) the perceived fairness of shifting costs of investments made with particular large customers' loads in mind to other customers if the large load does not persist.

V. CONCLUSIONS

AESO is in the process of updating its cost-of-service methods and transmission rate structure to reflect the current industry structure and evolving system conditions. Based on our review of the materials provided by AESO and discussions with AESO staff, we identified six key questions regarding functionalization, classification and recovery of Bulk wires costs. Our answers are summarized below. On the whole we find AESO's proposed approach reasonable, although we do offer suggestions for a few refinements.

1. Should the factors affecting the original investment or the nature of current use of the transmission facilities be used as the basis for sub-functionalization, classification and rate design?

For consistency with industry standards and the EUB's goal of providing appropriate price signals that reflect costs and benefits, functionalization, classification and rate design methods should reflect current system conditions and use rather than the factors affecting the original investment decisions. We believe that AESO's functionalization, classification and rate design methods do that.

2. Is there sufficient rationale for separating Bulk and Local wires costs for purposes of rate design?

No. Standard industry practice is to combine bulk and local costs unless there are separate rates for customers who use only the Bulk system. Most AESO customers use both the Bulk and Local systems and AESO's charges do not differentiate by interconnection voltage.

Furthermore, AESO's detailed analysis suggests that planning for both Bulk and Local system additions is fundamentally a matter of providing sufficient capacity to accommodate loads under adverse conditions, and that the critical periods occur at different times on different segments of both the Bulk and Local systems. In addition, AESO's classification of Bulk and Local costs results in very similar energy- and demand-related percentages. Finally, with the proposed non-coincident peak (NCP) charging mechanism for Bulk demand-related costs, the Bulk and Local costs could logically be merged in the cost-of-service analysis and rate structure.

3. Is the use of a minimum system approach to identify demand and energy components of Bulk lines appropriate?

Yes. Classification of a portion of transmission costs to energy is a standard industry practice, although less common than treating all transmission as demand-related. We

believe that AESO's minimum system analysis of the Bulk costs is a reasonable way to identify the share of costs spent to reduce losses. This approach is consistent with one of the rationales for energy classification mentioned in the NARUC Manual.

4. Is the partial recovery of demand-related Bulk costs on an energy basis appropriate?

AESO has not provided a convincing rationale for recovering a portion of the Bulk costs identified as demand-related on an energy basis. Furthermore the adjustment mechanism, applied for this purpose to the costs classified as demand related, is inconsistent with AESO's conceptual approach to the cost-of-service analysis. If AESO believes that some portion of the costs classified to demand should be recovered on an energy basis, it should provide a rationale for this position and develop a non-arbitrary method for doing so. For example, AESO could use a version of the "Average and Excess" (A&E) allocation method, which uses the system load factor to define the percentage of costs to be allocated on the basis of energy, and one minus the system load factor to define the portion to be allocated using NCP.

5. Is Customer NCP an appropriate cost recovery method for demand-related Bulk system costs?

Yes. Given (1) the diverse loading patterns on AESO's Bulk system (both in terms of location and timing), (2) the difficulty of predicting when and where system stress will appear, and (3) the requirement that rates not be location-differentiated, Alberta transmission system users should face incentives to carefully control loads in all hours. AESO's proposal to recover demand-related Bulk system costs on the basis of NCP will provide a very strong incentive to engage in this beneficial behaviour whenever there is any likelihood of the customer's setting a new peak. In addition, the NCP approach treats each hour as potentially an hour of system stress, which is consistent with system characteristics.

6. Does AESO's proposed billing determinant dampen important customer incentives for efficiency that would be present in an alternative approach?

Yes. A disadvantage of the AESO proposal to use ratcheted NCP to recover demand-related Bulk system costs is that the incentive to control load will be reduced in hours unlikely to set the billing capacity, although those may be hours when the lines serving the customer are stressed. Other definitions of billing capacity might achieve a better balance of the need for customers to recognize the long-term implications of their loads and the need to give incentives to control loads every month. For example, reducing the 90-percent factor applied to contract capacity and the highest demand in the past 24 months could make NCPs in more months potential factors in the billing capacity calculation.

APPENDIX

METHODS USED IN SELECTED JURISDICTIONS

CANADA

Utilities

Hydro One, Ontario

Hydro One has just completed a transmission cost of service for the 2007 and 2008 transmission revenue requirements which will be submitted for approval to its regulator, the Ontario Energy Board. (The information that follows was obtained from the company's web site and it is not part of the official submission.) In the 2007-2008 cost of service study Hydro One functionalized their transmission system as follows:

- Network: Transmission assets serving all customers, Inter-area transmission between sources of generation & load, Network portion of Dual Function Lines- All customers pay;
- Line Connection: Lines and related functions dedicated to one or few customers, Includes connection portion of Dual Function Lines (customers using "regulated" transmission lines to connect to Network Stations pay);
- Transformation Connection: Transmission assets that step-down from above 50kV to below 50kV -- Customers using "regulated" transformation pay; and
- Transmission Meter Pool-Paid by customers for whom Hydro One provides regulated meter service

In the study, Network charges are allocated based on the higher of CP or 85% NCP (7am-7pm), Line Connection and transformation connection costs are allocated based on NCP, Transmission Meter costs are allocated based on the number of meter points.

Manitoba Hydro, Manitoba

Manitoba Hydro's 2005 Cost of Service study functionalized transmission lines and related facilities based on an analysis of voltage level, current use and function. The Transmission function is separated into facilities used solely by domestic consumers and into facilities used to interconnect Manitoba Hydro's central transmission grid with neighboring utilities. The Subtransmission Function includes non grid/radial transmission lines (greater than 100 kV), lower voltage (66 kV and 33 kV) subtransmission lines, the low voltage portion of the

substations and a share of communication equipment, administration buildings, general equipment and substation transformers in stock. These facilities are required to bring the power from the common bus network to the districts and local town. All transmission costs are considered demand-related and allocated using a 2 CP method calculating average summer and winter peaks (based on top 50 hours). Subtransmission is allocated based on NCP.

Newfoundland and Labrador Hydro, Newfoundland and Labrador

Newfoundland and Labrador Hydro (NLH) performs a COS study for each of the five geographic areas it serves. Their latest cost studies were done in 2003. The transmission function includes lines and terminal stations. The lines and terminal stations that integrate the source of power with the backbone transmission system have been assigned to the generation function. Transmission costs are classified as 100% demand-related and allocated on the basis of 1 CP.

Nova Scotia Power, Nova Scotia

Nova Scotia Power (NSP) classifies its transmission costs as demand-related and uses a 12 CP mechanism to split the revenue requirement between network and point-to-point uses of the transmission system. Transmission costs for bundled retail customers are classified between energy and demand based on the system load factor. The demand-related costs are allocated on the sum of 3 CP for the peak winter period. Network allocation in combination with NCP load determines the OATT network service rate.

Saskpower, Saskatchewan

Saskpower classifies its transmission costs as demand-related and uses system winter coincident peak (1 CP) to allocate costs to each class. Customer transformers costs are allocated on the basis of class maximum demand.

Transenergie, Quebec

Transenergie classifies its transmission costs as demand-related and uses a 12 CP basis for calculating monthly, weekly, daily and hourly rates for Point-to-Point service. However, it uses 1 CP to calculate the annual services (Network Integration and long term Point-to-Point).

UNITED STATES

In the US, depending on the specific arrangements in place, the Open Access Transmission Tariff (OATT) is either developed from estimates of region-wide transmission revenue requirements (in the case of ‘postage-stamp’ rates), or from local transmission owners’ revenue requirements, based on the control area where power is taken off the grid (‘license plate’ rates).

Independent System Operators

PJM

PJM's zonal Network Integration Transmission Service (NITS) charges are calculated by PJM for each network customer (including the transmission operators), for the zone in which the load of the customer is located. A transmission customer's daily NITS requirement is based on its load in the hour of the PJM peak load (1 CP) for the twelve consecutive months ending on October 31 of the year prior to the calendar year. The annual transmission revenue requirement is the total annual cost to support capital and O&M expenses for the transmission system for NITS.

New York Independent System Operator (NYISO)

Each transmission owner calculates its wholesale transmission revenue requirement (or Transmission Service Cost - TSC) to serve load within the New York control area, and recovers it on the basis of annual MWh.

Independent System Operator- New England (ISO-NE)

The Pool Transmission Facility (PTF) rate is equal to the sum of the annual transmission revenue requirements for all participating transmission owners (PTOs) divided by the sum of the coincident monthly peaks of all local networks. The monthly local network load is the coincident aggregate load of all network customers served in each local network in the hour in which the coincident local network load is at its maximum for the month.

California Independent System Operator (CAISO)

The transmission access charge (TAC) is allocated on a gross load basis. Gross load is defined as the energy (adjusted for losses) delivered to end-use customer loads directly connected to the system and located in a participating transmission owner's (PTO) service territory. It excludes load subject to wheeling access charges. The TAC is currently in a 10-year transition period (that started in 01/2001), in which it will go from utility-specific TAC to a single system, grid-wide rate. Currently, TAC-area rates are based on the transmission revenue requirement of the PTO. An increasing percentage of the total revenue requirement for all participants is divided by the ISO-wide load, while the remaining share is PTO-specific.

High Voltage Access Charges and Low Voltage Access Charges each comprise two components: the revenue requirement associated with the transmission facilities and the Transmission Revenue Balancing Account (TRBA), designed to flow through to the PTO Transmission Revenue Credits, which together are designed to recover each PTO's HV and LV

transmission revenue requirement.³⁰ After the completion of the transition period, the HV Access Charge will equal to the sum of the HV transmission revenue requirements of all PTO, divided by the sum of the gross loads of all PTOs.

Midwest Independent System Operator (MISO)

The zonal Network Integration Transmission rate in MISO is calculated based on the transmission owner's revenue requirement divided by the average of 12 coincident system peaks.

Utilities

Bonneville Power Administration

BPA's 2002 Wholesale Power Rate Development Study contains BPA's latest embedded COS study.³¹ BPA assigns its transmission facilities and corresponding costs to various "segments" according to the types of services they provide. Various technical sources, such as one-line diagrams and plans of service and the existing contracts provide a basis for classification. Currently, these segments include:

- **Generation Integration:** includes all facilities that connect the generating plants to the integrated transmission network. This segment is assigned to generation.
- **Network:** consists of the transmission facilities that transfer bulk power.
- **Utility Delivery:** consists primarily of substation facilities required to step down from transmission voltages to voltages below 34.5kV for delivery to the transmission customer's distribution system.
- **Industry Delivery:** consists of substations facilities required to deliver power to direct service industrial customers at voltages below 34.5-kV.
- **Southern Intertie:** a system of transmission lines that interconnect the Pacific North West to California power systems at the Oregon border.
- **Eastern Intertie:** the Garrison-Townsend 500 kV line and the associated substation facilities at Garrison.
- **Ancillary Services**

³⁰ Facilities and equipment at or above 200 kV are allocated to the HV and the revenue requirement for facilities and equipment below 200 kV are allocated to the LV revenue requirement.

³¹ 2002 Final Power Rate Proposal Wholesale Power Rate Development Study (WP-02-FS-BPA-05), May 2000.

Transmission costs are classified 100% as demand-related. In 2002 the company analyzed the possibility of using 12 CP consistent with FERC standard method. However, it was determined that considerable cost shifts among the network services would have resulted, and the company proposed a 1 CP allocation. The 2002 final rates were therefore based on a negotiated settlement that specified rate levels.

PacifiCorp

PacifiCorp's transmission function includes the costs associated with the high voltage system utilized for the bulk transmission of power from generation sources and interconnected utilities to the load centers. Classification of transmission costs follows arbitrary percentages: 75% Demand and 25% energy. Demand-related transmission and generation costs are allocated using class contribution to the 12 monthly system firm peaks. According to the utility, demand costs are allocated in this manner because capacity is important to the company for meeting peak loads, load following and plant maintenance each month. PacifiCorp's summer and winter peaks are very similar. The spring and fall monthly peaks are somewhat lower, with PacifiCorp's lowest monthly peak generally around 80% of the annual maximum. Meeting peak load requirements, however, is also critical during the spring and fall months because that is when plants are taken out of service for maintenance. For these reasons, PacifiCorp supports the use of all 12 monthly peaks as the capacity allocation factor. The energy portion is allocated using class MWh adjusted for losses to generation level.

Puget Sound Energy

At Puget Sound Energy the costs of bulk and sub-transmission, as well as transmission used to integrate remote generation, are functionalized, classified, and allocated in the same manner as production costs – using the peak credit method. This method estimates the demand-related portion of transmission plant as the cost of a proxy generation capacity resource and treats the remaining share as energy-related. The demand-related costs are allocated based on class contribution to the load during the system's 200 coincident peak hours.

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Saskpower Cost of Service & Rate Design Methodology

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