Attachment to AUC-AESO-005
Tariff Extracts and Decisions

Tariff Extracts
- 2001 Terms and Conditions, Decision 2000-57, August 8, 2000, effective January 1, 2001

Decisions
- Alberta Power Limited, Phase II General Rate Application, Decision E95102, October 20, 1995
- 2001 General Rate Application Part D, Decision 2001-6, February 2, 2001
- 2010 ISO Tariff Application, Decision 2010-606, December 22, 2010
Definition of Accredited Generating Units for Generation Pool Access Service

To qualify as an accredited generating unit for transmission service, there must be a net power flow into the transmission system (and therefore into the Pool) at the point of interconnection with the generator.

Where a customer with load has on-site generation (both the load and generation are "inside the fence"), the Transmission Administrator may treat the generation in one of two basic ways, and will require a long term contractual agreement with the accredited generating unit and/or the distributor, depending on whether there is a net power flow into or out of the system. The two basic configurations are:

1) The on-site generator is assumed to directly supply the load, and the net power flow will be treated as one service by the Transmission Administrator. If there is a net physical flow of power into the pool, the Transmission Administrator will require a long term agreement with the generator under Rate Schedule GPA. If there is a net physical take of power, the Transmission Administrator will require a long term agreement with the distributor under Rate Schedule GIS and GSS, or GOS.

2) The on-site generation is segregated from the load, and there are two physical points of interconnection with the transmission system, which are metered and contracted for separately. The load will be served by the Transmission Administrator via a contract with the appropriate distributor under Rate Schedule GIS and GSS, or GOS, and the generator will be required to contract with GridCo under Rate Schedule GPA.

Modifications to these two basic configurations may be made, whereby a portion of the output of the on-site generation may be separately interconnected and treated as a generator under Rate Schedule GPA. The remaining generator output may serve the load (or part of the load), and the net load is contracted for under Rate Schedule GIS and GSS, or GOS.

Transmission Grid Investment Policy

Investments will be made in transmission grid facilities (as defined by the Electric Utilities Act) required to serve new distributor load, or to improve or maintain the standard of service, and such costs will be rolled into the transmission grid rates as follows:

1) All "system" additions, reinforcements or upgrades required to serve the new load or improve the standard of service. "System" is defined as any part of the transmission grid network not defined as "distributor related".

Although the Transmission Administrator will invest in 100% of "system" addition.
costs, distributors will be required to contract for a minimum GSS demand level at
the respective point or points of delivery, equivalent to the area system load forecast
that motivates the need for the system addition or improvement.

GSS charges will be based on the higher of the sum of the individual actual GSS
demands (calculated as the GIS Billing Demand multiplied by the On-Peak Load
Factor) in the area or the minimum contracted GSS demand level of the area for
which the system addition is being built. Where the minimum contracted GSS
demand is used, the charge will be prorated among the applicable points of delivery
on the basis of their actual GSS demands.

2) Any "distributor related" additions, reinforcements or upgrades required to serve the
new load up to the maximum distributor investment level. "distributor related" is
defined as any radial facility "downstream" of the network branch closest to the new
distributor load, that would be salvaged if the new distributor load were to disappear.

The maximum amount that the Transmission Administrator will invest in the
distributor level will be established as a function of the contract MW supplied, and
contract length or exit provision, such that distributor related investments are rate
neutral in the long run. The following table shows the level of investment in relation
to contract term:

<table>
<thead>
<tr>
<th>Investment Level</th>
<th>Contract Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>$115/kW</td>
<td>5 years</td>
</tr>
<tr>
<td>$200/kW</td>
<td>10 years</td>
</tr>
<tr>
<td>$265/kW</td>
<td>15 years</td>
</tr>
<tr>
<td>$310/kW</td>
<td>20 years</td>
</tr>
</tbody>
</table>

There will be no payment or equivalent rate discount to any distributor if the
distributor's new load can be served without exhausting the maximum distributor
investment.

All transmission grid additions or expansions will be based on good, least cost
engineering solutions. (For example, this could include underground cables where
the cost of aerial wires would be prohibitive or publicly unacceptable such as a
major metropolitan area or a national park.)

1) No investments will be made in any facilities required to accommodate any
generation, energy imports, or exports.
ARTICLE 9
CUSTOMER CONTRIBUTION POLICY

9.1 In considering requests for service at a new POD or POS or to increase the capacity of, or improve the existing standard of service at an existing POD or POS, the Transmission Administrator will determine the appropriate means of delivering the requested service. The Transmission Administrator will also determine the system-related costs, the Customer-related costs and the Customer contribution subject to this Article 9.

9.2 Any cost of providing new or increased levels of service associated with non-radial elements of the System as it exists, or as it is planned, will be classified as system related costs and rolled into the Tariff. All radial costs will be classified as customer related costs.

9.3 The amount to be paid as the Customer contribution portion of customer related costs for a new or expanded service will be calculated as follows:

(a) Customer contribution = customer related costs minus the Roll-in Ceiling.
(b) Roll-in Ceiling = Commitment Term Amount plus the Revenue Related Amount.
(c) Commitment Term Amount = $2 million dollars for every five (5) year commitment term after the first five year commitment term. A commitment term is a five year period within which the Customer commits to maintain its Contract Capacity at or above its initial Contract Capacity.
(d) Revenue Related Amount = three times the incremental annual revenue from the new or expanded service.

The maximum number of commitment terms is four, resulting in a maximum commitment amount of $6 million. If the result of the Customer contribution calculation is negative, no payment will be made to the Customer.

9.4 If the Transmission Administrator determines that a request for service would be more economically satisfied by a distribution level extension, by isolated generation, or primarily represents a shift of demand from an existing POD, then the Roll-in Ceiling will be zero.

9.5 The Roll-in Ceiling for Customers requiring service under Rate Schedules STS, DOS, Import Service and Export Service is zero.

9.6 If a Customer, who has benefited from a Roll-in of Customer related costs, reduces its Contract Capacity before the completion of its commitment terms, the Transmission Administrator shall recalculate the Customer contribution based on the revised commitment terms and revised Revenue Related Amount. The Customer shall pay the Transmission Administrator the difference between the original Customer contribution and the revised Customer contribution plus an interest payment at a rate of twelve percent (12%) per year for the number of years between the date of the original Customer contribution and the revised Customer contribution.

Schedule “B”
9.7 Any Customer contribution that is required to be paid to the Transmission Administrator must be paid prior to the Transmission Administrator initiating procurement of the required facilities, unless other credit arrangements acceptable to the Transmission Administrator are made.

9.8 The cost estimate used in the calculation of Customer-related costs will be based upon assumptions with respect to the method of construction and the routing of the facilities, including but not limited to, approvals and rights of way required to serve the Customer in accordance with the Customer's requests.

In the sole opinion of the Transmission Administrator, where a request for service is changed by a Customer, or the assumed timing, method of construction, or routing of facilities, are changed for reasons beyond the reasonable control of the Transmission Administrator, or the TFO and the variance in the cost of the required facilities over the original estimate results, then:

(a) Subject to (b), where there is an increase in the Customer Contributions this amount is immediately payable to the Transmission Administrator, or

(b) Where feasible, the Customer or the Transmission Administrator may modify the terms of the contract to adjust Contract Capacity or the term of the contract.

9.9 The Customer shall, in such case as contemplated under Paragraph 9.8, have the right to cancel the request for service by paying to the Transmission Administrator, and or the TFO, all costs then incurred or required to be incurred to discharge the Transmission Administrator, and or TFO, of all obligations and satisfactorily cancel the request for System Access Service.

9.10 If the Transmission Administrator installs facilities to provide System Access Service to a Customer who was assessed a Customer contribution, then uses the same facilities within ten (10) years of energization of the original Customer to serve other Customers, the Transmission Administrator will adjust the original Customer's contribution and assess the new Customers contribution on the basis of:

(a) the commitment term of the original and new Customers;

(b) the Revenue Related Amount of the original and new Customers;

(c) the extent of shared facilities;

(d) Contract Capacity of the original and new Customers; and

(e) The time interval between the energization of the original and the new Customers.

If the interval described in (e) exceeds five years, then the adjustment to the original Customer's contribution will be determined on a declining balance basis with the balance being zero in the tenth (10th) year. An adjustment as described above will also apply to situations where the Transmission Administrator subsequently deems
that all or part of an original Customer's interconnection facilities have become system related.

9.11 Where relocation of transmission facilities is required, the Transmission Administrator will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

9.12 Where new facilities between the adjacent Control Areas are required, the costs of such facilities will be shared equally between the Transmission Administrator and the party responsible for costs in the other Control Area.
ARTICLE 9
CUSTOMER AND SYSTEM CONTRIBUTION POLICY

9.1 Service Requirements
In considering requests to provide service to a new POC, or to increase the capacity of or improve the service to an existing POC, the AESO will determine the appropriate means of delivering the requested service.
(a) If the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension (“the project”)
(b) If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then the customer will pay the difference in cost between the most economic option and the transmission upgrade or extension in addition to any customer contribution required under Articles 9.3 through 9.6.
Otherwise:
(c) for a Point of Delivery Customer, the Customer’s contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and
(d) for a Point of Supply Customer, the Customer’s contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and the Customer’s System Contribution will be determined in accordance with Article 9.11.

9.2 Payment of Contributions
All Customer Contributions and System Contributions required under this Article 9 must be paid by the Customer before the start of construction of transmission facilities to provide the requested service. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.

9.3 Classification of System and Customer-Related Costs
The AESO will classify project costs as either system-related costs or Customer-related costs, as follows.
(a) For a Point of Delivery Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions and enhancements at existing adjacent substations. Such costs will normally include the point of interconnection, new transmission line, communication at the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer’s interconnection.
(b) For a Point of Supply Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions. Such costs will normally include the point of interconnection, new transmission line, communications at the point of interconnection back to the existing system, and a new breaker at an existing substation if required.
(c) System-related costs are those project costs associated with:
(i) looped transmission facilities;
Radial transmission extensions if the transmission development plan (as that plan exists on the date the project is Commissioned) proposes that the Radial transmission extension becomes Looped within five years. The Customer will pay the cost of advancing that part of the project from the date established in the transmission development plan, calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.14; and

Where, in the sole opinion of the AESO, economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed, then the AESO will classify that portion of the project deemed to be in excess of the Customer’s needs as system-related costs. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer’s requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer’s requirements.

Where the Customer requests an interconnection configuration that, in the sole opinion of the AESO, exceeds AESO Standard Facilities, the Customer must pay all customer and system costs in excess of AESO Standard Facilities.

Prepaid Operations and Maintenance

For customers taking service under Rate DTS, a prepaid operations and maintenance charge of 12% will be added separately to the costs of:

(a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and

(b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

Determination of Supply-Related and Demand-Related Costs

Customer-related costs will be classified as either supply-related costs or demand-related costs, as follows:

(a) The fraction of Customer-related costs classified as supply-related shall be STS/(STS+DTS), where STS and DTS are the STS and DTS Contract Capacities, respectively, at the POC. All supply related costs shall be paid by the Customer.

(b) The Customer-related costs not classified as supply-related costs shall be classified as demand-related costs. The Customer’s contribution to demand-related costs shall be in accordance with Article 9.6.

Determination of Customer Contribution

Customers may be required to contribute toward demand-related costs. The Customer’s contribution to demand-related costs will be determined in accordance with this Article 9.6. Otherwise, the Customer must pay all demand-related costs.
The Customer's contribution to the demand-related costs will be calculated as follows:

Customer Contribution = Demand-related costs less the Local Investment

Where:
(a) for a Customer taking service under Rate DTS:
   (i) the maximum Local Investment =
       • $125,000/year of DTS contract term for new PODs; plus
       • $5,000/MW of DTS Contract Capacity/year of DTS contract term
         for both new PODs and increases in capacity of or improvements
         to the service to an existing POD;
   (ii) the Local Investment will not exceed the demand-related costs
         determined in Article 9.5(b) or, if applicable, the cost of the most
         economic option determined in Article 9.1(b); and
   (iii) the DTS contract term = 5 to 20 years, as determined by the
         Customer;

and
(b) for a Customer taking service under any other rate, the maximum Local Investment = $0.

9.7 Staged Loads
(a) Local investment for projects with expected material increases or decreases
    in contract load will be determined at the start of the project by taking the
    present value of the local investment in the incremental load for the remaining
    contract term.
(b) If the material increases or decreases in contract load do not occur as
    expected an adjusted customer contribution may be recalculated in
    accordance with Article 9.9.
(c) The discount rate used in the present value calculation of Article 9.7(a) shall
    be determined in accordance with Article 9.14.

9.8 Changes to Project Costs
The cost estimate used in the calculation of project costs will be based on certain
assumptions including, but not limited to, assumptions about the method of
construction, the routing of facilities, and the approvals and rights of way required to
serve the Customer in accordance with the Customer's requests. In the sole opinion
of the AESO, where a request for service is changed by a Customer or any
assumptions are changed for reasons beyond the reasonable control of the AESO or
the TFO, and a variance in the cost of the required facilities over the original estimate
results, then:
(a) subject to (b), where there is an increase in the Customer Contribution, this
    amount is immediately payable to the AESO, or
(b) if feasible, the Customer and the AESO may modify the DTS System Access
    Service Agreement to adjust the contract term and/or the Contract Capacity,
    or
(c) the Customer will have the right to cancel the request for service by paying to
    the AESO, and/or the TFO, all costs then incurred or required to be incurred
to discharge the AESO, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.9 Changes to Customer Contribution

Certain material events may, in the AESO's sole opinion, result in an adjusted Customer Contribution and as appropriate, payments by the AESO to the Customer or by the Customer to the AESO. Either the Customer or the AESO may initiate a recalculation of the Customer Contribution at any time prior to the expiration of the twenty year refund period as set out in Article 9.10. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) a Customer materially increases or decreases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement;

(b) the actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;

(c) a facility that had been classified as system-related under Article 9.3(c) is reclassified as Customer-related due to load growth or the addition of a new POC;

(d) a material error is detected in the original calculation;

(e) there is a material difference between the estimated costs of the project and the actual costs of the project;

(f) the AESO subsequently deems that all or part of a Customer's Facilities have subsequently become system-related; or

(g) the period of advancement as set out in Article 9.3(c) is materially reduced.

9.10 Shared Facilities

(a) If the AESO installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the AESO will adjust the original Customer’s contribution and assess each of the new Customers a contribution, as follows:

(i) the DTS contract terms of the original and new Customers;

(ii) the Contract Capacities of the original and new Customers;

(iii) the extent of shared facilities; and

(iv) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(iv) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11 any project whose remaining contribution adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, and no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the AESO subsequently deems that all or part of an original Customer’s facilities have become system-related.

9.11 Determination of System Contribution
(a) In addition to the Customer Contribution determined in Articles 9.3 through 9.6, a Customer taking service under Rate STS is required to pay a System Contribution for:

(i) new STS Capacity requirements at a new Point of Supply, and
(ii) new STS Capacity requirements at an existing Point of Supply where such additional requirements are the result of the addition of a new Generating Unit.

(b) The System Contribution is the sum of the following:

(i) $10,000/MW multiplied by the amount of new STS Contract Capacity, plus
(ii) $40,000/MW multiplied by the amount of new STS Contract Capacity multiplied by the Customer’s System Contribution Factor. System Contribution Factors will be determined by the AESO for areas of the transmission system where generation exceeds load in accordance with Section 17 of the Transmission Regulation, and will be made publicly available by the AESO in advance of their effective dates.

(c) System Contributions are not required for STS Capacity requirements for which a System Access Service Agreement was signed before January 1, 2006.

9.12 Refund of System Contribution

(a) A Customer’s System Contribution will be refunded to the Customer if the Customer’s generating unit meets the ISO Rules regarding satisfactory annual performance, in accordance with the provisions of this Article 9.12.

(b) The System Contribution will be refunded in annual amounts within a maximum of 10 calendar years following the date it was paid, but not before the planned Commercial Operation date of the generating unit. The planned Commercial Operation date is the date requested by the Customer and agreed to by the AESO at the time of payment of the System Contribution. The planned Commercial Operation date may be adjusted due to delays in the availability of System Access Service clearly attributable to matters for which the AESO or the TFO is reasonably accountable.

(c) A base amount will be determined by dividing the System Contribution by the number of years in the “Refund Period”. The Refund Period is the period from January 1 following the planned Commercial Operation date of Article 9.12(b) to December 31 of the tenth calendar year after the System Contribution was paid.

(i) The annual amount in the first half of the Refund Period will be 50% of the base amount.
(ii) The annual amount in the last half of the Refund Period will be 150% of the base amount.
(iii) Where the Refund Period includes an odd number of calendar years, the annual amount in the mid-point year will be 100% of the base amount.

(d) If Commercial Operation of the generating unit is delayed for any reason beyond December 31 of the year of the planned Commercial Operation date of Article 9.12(b), then for each calendar year or fraction thereof during the Refund Period that Commercial Operation is delayed, the annual amount for that year or fraction thereof will be forfeited.
(e) For each calendar year or fraction thereof during the Refund Period in which the ISO Rules regarding satisfactory annual performance are met after Commercial Operation of the generating unit, the Customer will receive a refund of the annual amount determined in (c) for that year or fraction thereof. If the ISO Rules regarding satisfactory annual performance are not met, the annual amount for that year or fraction thereof will be forfeited.

(f) For each year of the Refund Period, the Customer must report the unit’s annual performance to the AESO by January 31 of the following year.

(g) For each year of the Refund Period where the Customer has reported annual performance and where the ISO Rules regarding satisfactory annual performance are met, the AESO will pay the System Contribution refund annual amount to the Customer by February 28 of the following year.

9.13 Limitations
The AESO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the AESO may:

(a) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as Customer-related.

(b) Determine that a refund of a Customer Contribution or a System Contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.

(c) Determine that a refund of a Customer Contribution or a System Contribution must be returned to the AESO where it is demonstrated that an error was made or that an inappropriate refund was given.

9.14 Discount Rate
The discount rate applicable to payments due under this Article 9 will be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the AESO by an investor owned Transmission Facility Owner or for facilities supplied to the AESO by an income tax paying municipally owned Transmission facility Owner:

\[
[0.67 \times (GCB + 1\%)] + [(0.33 \times 8.93\%) \div (1 – T)]
\]

where GCB is equal to the yield on 30-year Government of Canada bonds and T is equal to combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the AESO by a non income tax paying municipally owned Transmission Facility Owner:

the yield on 30-year Government of Canada bonds plus 1.9 percent.

9.15 Miscellaneous
(a) Where relocation of transmission facilities is required, the AESO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

(b) Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the AESO and the party responsible for costs in the other Control Area.

(c) The Customer must pay the cost of any Customer requested facilities that, in the sole opinion of the AESO, exceed the AESO Standard Facilities required to provide service to the Customer.
ARTICLE 9
CUSTOMER AND SYSTEM CONTRIBUTION POLICY

9.1 Service Requirements
In considering requests to provide service to a new POC, or to increase the capacity of or improve the service to an existing POC, the AESO will determine the appropriate means of delivering the requested service.

(a) If the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension ("the project")

(b) If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then the customer will pay the difference in cost between the most economic option and the transmission upgrade or extension in addition to any customer contribution required under Articles 9.3 through 9.6.

Otherwise:

(c) for a Point of Delivery Customer, the Customer’s contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and

(d) for a Point of Supply Customer, the Customer’s contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and the Customer’s System Contribution will be determined in accordance with Article 9.11.

9.2 Payment of Contributions
All Customer Contributions and System Contributions required under this Article 9 as determined at the time the Customer executes the necessary agreements signifying commitment as per the AESO’s interconnection processes, must be paid by the Customer before the start of construction of transmission facilities to provide the requested service. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.

9.3 Classification of System and Customer-Related Costs
The AESO will classify project costs as either system-related costs or Customer-related costs, as follows.

(a) For a Point of Delivery Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions and enhancements at existing adjacent substations. Such costs will normally include the point of interconnection, new transmission line, communication at the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer’s interconnection.

(b) For a Point of Supply Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions. Such costs will normally include the point of interconnection, new transmission line, communications at the point of
interconnection back to the existing system, and a new breaker at an existing substation if required.

(c) System-related costs are those project costs associated with:

(i) Looped transmission facilities;

(ii) Radial transmission extensions if the transmission development plan (as that plan exists on the date the project is Commissioned) proposes that the Radial transmission extension becomes Looped within five years. The Customer will pay the cost of advancing that part of the project from the date established in the transmission development plan, calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.14; and

(iii) Where, in the sole opinion of the AESO, economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed, then the AESO will classify that portion of the project deemed to be in excess of the Customer’s needs as system-related costs. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer’s requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer’s requirements.

(d) Where the Customer requests an interconnection configuration that, in the sole opinion of the AESO, exceeds AESO Standard Facilities, the Customer must pay all customer and system costs in excess of AESO Standard Facilities.

9.4 Operations and Maintenance
For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of:

(a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and

(b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

9.5 Determination of Supply-Related and Demand-Related Costs
For each Customer at a substation, Customer-related costs will be classified as either supply-related or demand-related as follows:

(a) supply-related costs shall be calculated as \( \frac{\text{STS}_{\text{customer}}}{\text{STS}_{\text{total}} + \text{DTS}_{\text{total}}} \), and

(b) demand-related costs shall be calculated as \( \frac{\text{DTS}_{\text{customer}}}{\text{STS}_{\text{total}} + \text{DTS}_{\text{total}}} \)

where STS and DTS are the STS and DTS Contract Capacities, respectively, at the substation. All supply-related costs shall be paid by the Customer. The Customer’s contribution to demand-related costs shall be in accordance with Article 9.6.
9.6 Determination of Customer Contribution

Customers may be required to contribute toward demand-related costs. The Customer’s contribution to demand-related costs will be determined in accordance with this Article 9.6. Otherwise, the Customer must pay all demand-related costs.

The Customer’s contribution to the demand-related costs will be calculated as follows:

Customer Contribution = Demand-related costs less the Local Investment

Where:

(a) for a Customer taking service under Rate DTS:

(i) the maximum Local Investment where the TFO provides and owns conventional transformation facilities =

- $51,400.00/year of DTS contract term for new PODs, multiplied by the Substation Fraction; plus
- $28,900.00/MW of DTS Contract Capacity/year of DTS contract term for the first (7.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $10,000.00/MW of DTS Contract Capacity/year of DTS contract term for the next (9.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $5,900.00/MW of DTS Contract Capacity/year of DTS contract term for the next (23 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $3,100.00/MW of DTS Contract Capacity/year of DTS contract term for all remaining MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD.

(ii) the maximum Local Investment where the Customer purchases, owns, and operates the Customer’s own transformation facilities or is served through an unconventional interconnection such as those using metering transformers =

- $23,130.00/year of DTS contract term for new PODs, multiplied by the Substation Fraction; plus
- $13,005.00/MW of DTS Contract Capacity/year of DTS contract term for the first (7.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
• $4,500.00/MW of DTS Contract Capacity/year of DTS contract term for the next (9.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
• $2,655.00/MW of DTS Contract Capacity/year of DTS contract term for the next (23 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
• $0.00/MW of DTS Contract Capacity/year of DTS contract term for all remaining MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD.

(iii) the Local Investment will not exceed the demand-related costs determined in Article 9.5(b) or, if applicable, the cost of the most economic option determined in Article 9.1(b); and

(iv) the DTS contract term = 5 to 20 years, as determined by the Customer;

and

(b) for a Customer taking service under any other rate, the maximum Local Investment = $0.

9.7 **Staged Load & Contract Capacity Increases**

(a) Where material increases or decreases in Contract Capacity are contemplated at a POC and contracted for in the original System Access Service Agreement then:

(i) Local investment for projects with expected material increases or decreases in contract load will be determined at the start of the project by taking the present value of the local investment in the incremental load for the remaining contract term;

(ii) If the material increases or decreases in contract load do not occur as expected an adjusted customer contribution may be recalculated in accordance with Article 9.9;

(iii) The discount rate used in the present value calculation of Article 9.7(a) shall be determined in accordance with Article 9.14.

(b) For increases in Contract Capacity contracted prior to the expiration of the original System Access Service Agreement which require the construction of new transmission facilities after the original interconnection then:

(i) The approved Tariff at the time the Customer executes the necessary agreements signifying commitment for the new Contract Capacity will be used in the customer contribution calculation;

(ii) Only the incremental contracted capacity will be used in the customer contribution calculation.
9.8 Changes to Project Costs
The cost estimate used in the calculation of project costs will be based on certain assumptions including, but not limited to, assumptions about the method of construction, the routing of facilities, and the approvals and rights of way required to serve the Customer in accordance with the Customer’s requests. In the sole opinion of the AESO, where a request for service is changed by a Customer or any assumptions are changed for reasons beyond the reasonable control of the AESO or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) subject to (b), where there is an increase in the Customer Contribution, this amount is immediately payable to the AESO, or
(b) if feasible, the Customer and the AESO may modify the DTS System Access Service Agreement to adjust the contract term and/or the Contract Capacity, or
(c) the Customer will have the right to cancel the request for service by paying to the AESO, and/or the TFO, all costs then incurred or required to be incurred to discharge the AESO, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.9 Changes to Customer Contribution
Certain material events may, in the AESO’s sole opinion, result in an adjustment to the Customer Contribution and as appropriate, payments by the AESO to the Customer or by the Customer to the AESO. Adjustment calculations will rely on the tariff in effect at the time of the request for System Access Service (which may differ from this tariff). Either the Customer or the AESO may initiate an adjustment of the Customer Contribution at any time prior to the expiration of the twenty year refund period as set out in Article 9.10. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) a Customer materially increases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement and does not necessitate the construction of new transmission facilities;
(b) a Customer materially decreases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement;
(c) the actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;
(d) a facility that had been classified as system-related under Article 9.3(c) is reclassified as Customer-related due to load growth or the addition of a new POC;
(e) a material error is detected in the original calculation;
(f) there is a material difference between the estimated costs of the project and the actual costs of the project;
(g) the AESO subsequently deems that all or part of a Customer’s Facilities have subsequently become system-related; or
(h) the period of advancement as set out in Article 9.3(c) is materially reduced.

9.10 Shared Facilities
(a) If the AESO installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the AESO will adjust the original Customer’s contribution and assess each of the new Customers a contribution, as follows:

(i) the DTS contract terms of the original and new Customers;
(ii) the Contract Capacities of the original and new Customers;
(iii) the extent of shared facilities; and
(iv) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(iv) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11 any project whose remaining contribution adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, and no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the AESO subsequently deems that all or part of an original Customer’s facilities have become system-related.

9.11 Determination of System Contribution

(a) In addition to the Customer Contribution determined in Articles 9.3 through 9.6, a Customer taking service under Rate STS is required to pay a System Contribution for:

(i) new STS Capacity requirements at a new Point of Supply, and
(ii) new STS Capacity requirements at an existing Point of Supply where such additional requirements are the result of the addition of a new Generating Unit.

(b) The System Contribution is the sum of the following:

(i) $10,000/MW multiplied by the amount of new STS Contract Capacity, plus
(ii) $40,000/MW multiplied by the amount of new STS Contract Capacity multiplied by the Customer’s System Contribution Factor. System Contribution Factors will be determined by the AESO for areas of the transmission system where generation exceeds load in accordance with Section 29 of the Transmission Regulation, and will be made publicly available by the AESO in advance of their effective dates.

(c) System Contributions are not required for STS Capacity requirements for which a System Access Service Agreement was signed before January 1, 2006, or for STS Capacity requirements of 1 MW or less.

9.12 Refund of System Contribution

(a) A Customer’s System Contribution will be refunded to the Customer if the Customer’s generating unit meets the ISO Rules regarding satisfactory annual performance, in accordance with the provisions of this Article 9.12.
(b) The System Contribution will be refunded in annual amounts during the “Refund Period”. The Refund Period begins on January 1 following the Commercial Operation date of the Customer’s generating unit and ends nine calendar years later on December 31.

(c) The annual amounts during the Refund Period will be:

(i) 5.6% of the System Contribution in each of the first through fourth calendar years in the Refund Period;

(ii) 11.2% of the System Contribution in the fifth calendar year in the Refund Period; and

(iii) 16.6% of the System Contribution in each of the sixth through ninth calendar years in the Refund Period.

(d) For each calendar year during the Refund Period in which the ISO Rules regarding satisfactory annual performance are met, the Customer will receive a refund of the annual amount determined in (c) for that year. If the ISO Rules regarding satisfactory annual performance are not met, the annual amount for that year will be forfeited.

(e) For each year of the Refund Period, the Customer must report the unit’s annual performance to the AESO by January 31 of the following year.

(f) For each year of the Refund Period where the Customer has reported annual performance and where the ISO Rules regarding satisfactory annual performance are met, the AESO will pay the System Contribution refund annual amount to the Customer by February 28 of the following year.

9.13 Limitations

The AESO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the AESO may:

(a) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as Customer-related.

(b) Determine that a refund of a Customer Contribution or a System Contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.

(c) Determine that a refund of a Customer Contribution or a System Contribution must be returned to the AESO where it is demonstrated that an error was made or that an inappropriate refund was given.
9.14 **Discount Rate**

The discount rate applicable to payments due under this Article 9 will be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the AESO by an investor owned Transmission Facility Owner or for facilities supplied to the AESO by an income tax paying municipally owned Transmission Facility Owner:

\[
[0.67 \times (GCB + 1\%) + (0.33 \times R) ÷ (1-T)]
\]

where GCB is equal to the yield on 30-year Government of Canada bonds; R is equal to the AUC approved generic rate of return on common equity, as amended from time to time; and T is equal to the combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the AESO by a non income tax paying municipally owned Transmission Facility Owner:

the yield on 30-year Government of Canada bonds plus 1.9 percent.

9.15 **Miscellaneous**

(a) Where relocation of transmission facilities is required, the AESO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

(b) Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the AESO and the party responsible for costs in the other Control Area.

(c) The Customer must pay the cost of any Customer requested facilities that, in the sole opinion of the AESO, exceed the AESO Standard Facilities required to provide service to the Customer.
ALBERTA ENERGY AND UTILITIES BOARD

DECISION E95102

re:

ALBERTA POWER LIMITED
In the matter of the Phase II portion of a general rate application by Alberta Power Limited for an increase in the rates, charges or schedules for electric light, power or energy furnished to its customers in Alberta.

BEFORE:

B. T. McManus Q.C.    Presiding Member
A. Calista Barfett    Member

FILE 1102-4           October 20, 1995
5. INDIVIDUAL RATES, TOLLS OR CHARGES

(v) Rider A-2 - Surcharge

Board Findings

The Board notes that the MI's concerns were not dealt with by APL in reply argument. The Board expects that APL will address the concerns in its next Phase II filing.

xz

6. ELECTRIC SERVICE REGULATIONS

(a) Investment Policy

APL indicated that it had applied the average increase (4.9%) to the investment levels contained in the existing Electric Service Regulations (ESR). Existing industrial investment levels were the present value of the difference between expected revenues and upstream costs over the commercial life of representative services.

APL stated its current policy on early system developments. Where APL has previously identified a system need in an area...
6. ELECTRIC SERVICE REGULATIONS

(a) Investment Policy

provision of the system facilities is advanced to meet the needs of a new incremental customer, that customer will be allocated both the incremental customer and early system costs incurred. However, APL stated that the updating of plans and forecasts complicate application of that policy.

APL also summarized its response to the Board direction that APL should provide guidelines for "early system developments". APL took the position that there was no analytic or deterministic formula available to differentiate between system and customer related facility extensions. APL submitted that such differentiation should be made by applying professional judgement on a case by case basis, considering factors including the number of customers involved, the size and type of load, the size of the investment and load forecasts for the area. (Argument, pp.66-68)
6. ELECTRIC SERVICE REGULATIONS

(a) Investment Policy

IPCAA

IPCAA submitted that APL's indication that it has not yet been able to come up with any useful guidelines for "early system developments," should not mean that the search should be abandoned. IPCAA considered that APL accepted that it wouldn't be unreasonable to lay out potential guidelines for comment. (Argument, p.23)

Board Findings

The Board recognizes APL's position that there is no analytic or deterministic formula available which may be precisely set out to differentiate between system and customer related facility extensions. In addition, the Board considers that explicit definitions or detailed regulations may not allow for sufficient flexibility in their application if certain circumstances occur which had not been considered in the drafting of those definitions or regulations. Therefore, the Board accepts APL's current early investment policy as appropriate at this time and also accepts that it must be tempered with professional judgement on a case specific basis.

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ALBERTA ENERGY AND UTILITIES BOARD           DECISION E95102

- 150 -

October 20, 1995
ESBI Alberta Ltd.

1999/2000 General Rate Application
Phase 1 and Phase 2
16 TERMS AND CONDITIONS OF SERVICE

16.1 Customer Contributions

Customer contributions (sometimes termed contributions in aid of construction or CIAC) are a recognized feature for the provision of utility service. A utility may request a customer contribution for a hard-to-serve customer or where the expected revenue is insufficient to support the expected utility investment to serve that customer.

Position of EAL

EAL proposed, in Article 9 of the Terms and Conditions of Service, a SERP-based contribution/credit for demand customers (DTS Service) who chose to take demand service as of December 31, 1999 or for current customers who chose to increase their contract capacity after that date. The SERP charge/credit would be payable for the first 60 months on the contract capacity of any new System Access Service Agreement and would also be payable for the first 60 months upon any subsequent increase in capacity. The SERP payments were set out in Appendix D of the Terms and Conditions and were proposed to apply separately for the initial contract capacity and any subsequent increment thereto. Accordingly, the SERP amount would be the value shown in Appendix “D” as at the relevant date for the establishment of contract capacity or increment, being the effective date of the System Access Service Agreement or of the increase to the Contract Capacity, as applicable.

EAL also proposed that all customers taking service under either Rate Schedule DTS or Rate Schedule STS pay a customer contribution if new facility construction or upgrades (the “Facility”) were required to serve the Customer’s Contract Capacity requirements or increases thereto. The contribution was calculated as follows for each Billing Period, and based on the total capital cost of the Facility, subject to Paragraph 9.4 of the Terms and Conditions.

\[
10 \text{ per cent} \times \text{Capital cost of Facility}
\]

The customer contribution would be applicable for the first sixty (60) months of the term of the System Access Service, or for the first sixty (60) months commencing from an increase of contract capacity.

EAL also proposed that, for any capital addition in excess of $5 million, it reserved the right to assess an additional customer contribution that could allow it to recover up to 100 per cent of the cost in excess of $5 million.

Finally, EAL proposed that opportunity customers pay 100 per cent of the capital cost of facilities built to accommodate their required level of opportunity service.

In argument, EAL stated that the purpose of any Customer Contribution Policy is to balance the interests of new and old customers by reflecting a portion of the incremental cost of serving each new customer. EAL’s considered its Customer Contribution Policy balanced those interests in a fair and reasonable manner.
Concerning AE's concern with EAL's intention to spread collection of the contribution policy over 5 years. EAL interpreted this to be the risk of a DISCO financing the customer contribution for a customer who may disappear during the first 5-year period. EAL considered that its proposal was not likely to change the TFO cash flow as the effect would be positive or negative depending on the size of the extension. EAL considered that this was a normal forecast risk. If the extension cost less than $4 million, the DISCO would receive a higher contribution under the new policy than under the old policy. If the DISCO had a series of small extensions, its cash flow would be beneficially affected. EAL submitted that the DISCO cash flow would be adversely affected only if there were a series of very expensive extensions. EAL proposed supporting the DISCO in a rate adjustment application or in the use of deferral accounts, in the event of a negative effect on DISCO cash flow. EAL noted that this risk was minimal, having regard for the new customer credit review permitted by Article 10 of the T&C. In the event the Board found this to be a substantial risk, EAL proposed that the contribution be converted to an up-front present value payment.

EAL considered that a possible future refinement to its proposal was TCE's suggested amendment to Article 9 to make it more fair to the first customer that has paid the contribution, when a new customer comes along and uses the facilities to which the first has provided a cost contribution. EAL submitted that such a procedure should be implemented as a business practice following stakeholder consultations to review the various mechanisms by which this could be achieved.

EAL noted that there existed transitional projects\(^{379}\) that would come into being before the new tariff is approved. Consequently, these customers may be in the situation where they can not get the advantage under the existing contribution policy and would also get no advantage under the new one without some transitional application. EAL believed that a transition policy was fair and reasonable.

EAL stated that its proposal applied to the easily identifiable connection costs between the customer and the first node on the transmission system. EAL conceded that it was not possible to eliminate all debate over what constitutes "local connection costs". However, the EAL approach to the Customer Contribution Policy made the determination of local costs as straightforward and "as unambiguous as possible". The SERP-related portion of the customer contribution reflected the impacts of the new customer on the deeper system by allocating 25 percent of the SERP charge or credit. EAL noted that this was based on judgement. The balance of the deep system costs required to serve the new customer would be incorporated into the TFO's rate base. EAL submitted that its proposal simplified the customer contribution calculation, removed the considerable controversy over identifying and allocating incremental costs as between customer-related and system-related and avoided the last-straw problem when the ultimate requirement to re-enforce the system arrives. Both components of the proposal were simply a continuation of the philosophy of existing contribution policies. EAL submitted that with its proposal there was no discrimination based on vintaging and no question of "acquired rights" for existing customers.

EAL stated that its contribution policy was not a "rate" within the meaning of section 27 of the EUA. The EUA set out the definitions of "tariff", "rate", and "terms and conditions". A "tariff" is a document that sets out "rates" and applicable "terms and conditions", "Rates" are the prices, rates, tolls and charges that apply to service provided by an electric utility or the TA. "Terms and

\(^{379}\) Tr. page 1061
conditions" means the standards, classifications, regulations, practices, measures and terms and conditions that apply to service provided by an electric utility or the TA.

EAL considered that the Alberta legislature has specifically chosen to define "tariff" to include both "rates" and "terms and conditions". According to the definitions in the statute, "rates" are not the same as "terms and conditions". In Decision U98060, the Board approved the terms and conditions of NUL's tariff which included a provision as follows:

The Rates do not include extra costs incurred by the Company and payable by the Customer for Special Facilities or conditions requested by the Customer at the Point of Delivery or at the Point of Receipt.

Although the circumstances in the Northwestern case are not exactly the same as pertained to EAL, EAL submitted the case supported the proposition that "terms and conditions" of a tariff may contain financial provisions that require financial contribution from a customer and that a financial provision need not be classified as a "rate" necessarily. EAL noted that the "SERP to load" portion of its proposal was a specific five-year provision to recover special costs imposed upon the system by a particular customer. Ordinarily, a contribution would be payable immediately but EAL provided a five-year period to reduce the customer impact. EAL submitted that mitigation did not convert the customer contribution into a rate.

EAL noted that the "SERP to load" proposal was not critical to EAL's tariff proposal. EAL stated that it would withdraw the proposal if it was not acceptable to its customers. However, EAL did not believe that such a withdrawal was warranted. EAL submitted that withdrawal would result in a continuation of the endless disputes over who should pay what portion of the total incremental cost. This would be a burden on the TA's resources and increase the TA's costs.

In reply to AE's proposal that there should be no customer contributions, EAL stated that the DISCO is the customer of the TA. Just as the DISCO required its customers to pay connection charges, the costs incurred in making connection to the transmission system should be recovered from the TA's customer. EAL acknowledged that it may be impossible to fully distinguish bulk versus local facilities. EAL submitted that its proposal minimized contention while recognizing that local costs may extend beyond the first node.

Contrary to TCE's position, EAL submitted that its contribution policy provided fair treatment of all generators, as illustrated by the corrected version of TCE's Exhibit 43. This would place generation on exactly the same basis as load where existing load pays no contribution but new load does pay a contribution. In both cases, the contribution would be based on the incremental cost of service less an investment, which will be recovered from all customers through rates. EAL noted that load customers had not made any argument of unfairness or inability to compete concerning EAL's proposal.

Concerning TCE's proposal for pro rata sharing of customer contributions, EAL considered that this could be a future refinement of its contribution policy. EAL considered that this was a matter for future stakeholder consultations. Since EAL was undertaking a process of consultation, EAL submitted that no Board direction was necessary on this issue.
Position of IPPSA

In evidence\textsuperscript{380}, IPPSA noted that EAL would continue to collect a significant share of incremental attachment costs from unregulated generators and nothing from regulated generators, while collecting tariff generation charges from both. IPPSA suggested that, for EAL to be consistent and eliminate discrimination, it should identify the specific attachment costs for each existing, regulated generator. These attachment costs would then need to be subjected to EAL’s proposed contribution policy -- in effect, each regulated generator would be charged 10 percent of those costs each year of the next five years. While a study to develop attachment costs for regulated generators would be complex and subjective, IPPSA noted that the Board directed the TA to do so in its decision on the Gridco application.

IPPSA noted that in the proposed tariff, regulated generators would pay zero, while unregulated generators must make contributions pursuant to Section 9.3 of the Terms and Conditions. To completely eliminate such discrimination under the proposed approach, EAL’s contribution policy would need to require EAL to pay for all generator attachment costs, eliminating the 5-year, 10 percent per year requirement for new generation. Alternatively, if the existing tariff were retained, non-discrimination would require that existing generators pay an up-front charge for their connections. Unless one of these approaches is adopted, IPPSA stated it saw no reason why assigning a proxy attachment cost to regulated generators, to balance the contribution required from new generators, constituted undue discrimination.

With respect to new generators, IPPSA proposed that they pay the full cost of attachment to the transmission system. EAL’s proposal requiring new generators to pay 10 percent of attachment costs for each of the first five years should be denied. IPPSA considered that its proposal would provide the correct economic signals for new generators to locate such that they correctly balance the incremental costs of attaching to the transmission grid with the other considerations in their siting decision. IPPSA considered that EAL’s proposal would provide non-cost advantages to projects with higher attachment costs.

**Position of ENMAX**

ENMAX noted that Directive 11 of Decision U97065 directed the TA to study the relationship between the local and bulk portions of the transmission system. ENMAX considered that, although there may be a gray area with respect to some equipment, there was a clear difference between the two facility concepts, especially with respect to the transformation equipment used to supply power at the 25 kV level. ENMAX noted that all of its PODs share the same SERP value of $900 per MW month. No distinction was made as to the amount of excess capacity or the cost to expand any of the individual sites. ENMAX suggested this is because the SERP factors are based on the need for bulk lines between Edmonton and Calgary. ENMAX noted that, while transferring loads between any of their PODs would not change the bulk need, it would change the local needs at the stations themselves. ENMAX stated this suggested the use of a coincident peak ("CP") billing determinant was more appropriate for the bulk transmission system and system reserves. ENMAX considered that EAL took the very simplistic approach of lumping all facilities together and then utilizing non-coincident peak ("NCP") for its billing determinant, notwithstanding that NCP has no bearing on the use of the bulk facilities. ENMAX

\textsuperscript{380} Exhibit 93, pages 26, 33-34
requested that the Board direct EAL to study the issue, as outlined in its Directive 11, as part of EAL’s next GTA.

In Argument, ENMAX opposed the application of SERP to demand customers because it was contrary to the EU Act. ENMAX noted the EU Act specifically stated that rates “must not be different for owners of eligible distribution systems as a result of the location of those systems on the transmission system.” ENMAX submitted that there was no question that SERP for load customers was intended to send a locational signal. This locational signal SERP delivered to distribution companies is that the location of load in the Province is either advantageous or detrimental to system costs. The SERP signal applied to load therefore differs, depending upon location in the Province of the DISCO. ENMAX submitted that SERP to load violated the prohibition in the EU Act against rates being different as a result of location in the Province. EAL acknowledged that, if SERP were a rate, it would be prohibited within the definition of section 27(2) of the EU Act.

ENMAX noted that EAL attempted to distinguish SERP from a rate by analogy to a DISCO’s contribution policy. ENMAX disagreed that the EU Act could be narrowly construed to omit contributions as a rate. ENMAX noted that the policy paper, “Moving to Competition”, referred to “a system access tariff that is independent of where they are located in the province.” ENMAX submitted that this expression of intention by the Alberta Government was a clear and unequivocal statement of the legislative intention behind the postage-stamp requirement for demand customers.

Secondly, ENMAX submitted that the distinction between a rate and a tariff drawn by EAL is a distinction without a difference. ENMAX noted EAL’s response to EPCOR-EAL-36(c) acknowledging that application of SERP charges to demand customers after the first five years would contravene Section 27(2)(b) of the EU Act. ENMAX submitted that the SERP charge did not change its nature with the passage of time. If SERP to load would contravene the “postage stamp” requirement after five years, it would do so immediately.

ENMAX submitted that it was inappropriate to characterize monies collected from load customers for reinforcements to the backbone transmission system as contributions for the purpose of system access. ENMAX’s witness, Mr. Poole, stated that, while ENMAX had long used contribution policies, it has not used them for backbone facilities. Mr. Avery testified that utility companies have used contribution policies to recoup the cost of interconnecting individual customers at a particular location but they have not traditionally been used for the purposes to which EAL sought to put them. EAL’s proposal was not based on costs at a particular location but related to the relative costs between demand customers at different locations. ENMAX concluded that EAL’s SERP to load proposal was not analogous to contribution policies and were contrary to the postage-stamp requirements of subsection 27(2)(b) of the EU Act.

ENMAX concluded that SERP applied to demand customers would constitute a rate or a tariff, which would be different for owners of eligible distribution systems as a result of the location of those systems on the transmission system. This was prohibited by subsection 27(2)(b) of the EU Act and the Board should therefore reject any application of the SERP methodology to demand customers.
Even if SERP to demand customers were not prohibited by subsection 27(2)(b) of the EU Act, ENMAX considered it impractical apply. ENMAX noted that the examples of incremental load it presented in Exhibit 35, pp. 4-6, two of the three cases, “load creep” and the addition of a major load to an existing POD, would be administratively difficult, if not impossible to administer. ENMAX predicted that SERP to load would result in different rates charged to end use customers within the same class and, potentially, even to the same customer, for different segments of the same customer’s demand. DISCOs would then face the same problem of discriminatory rates within classes of customers, as would the TA.

ENMAX noted that EAL offered to retract its proposal to tie its demand customer contribution policy to the SERP methodology if the general consensus was against the proposal. ENMAX submitted that the record was clear that the DISCOs, as well as other interveners such as the FIRM Customers and IPCAA opposed EAL’s proposal. Since there was no support on the record for SERP to demand customers, ENMAX submitted that EAL should honour its offer to retract this portion of the application and return to the previous contribution policy.

Position of TransAlta

TransAlta noted that EAL characterized SERP on new loads as a customer contribution and not as a rate, despite the fact that SERP is definitely a rate for generation. TransAlta submitted that there is no basis for such a rationalization and no basis for differentiating new load from old under s. 27(2) of the Act. The fact that SERP on new load is a diluted signal does not alter it as a locational effect that is prohibited by the Act.

TransAlta considered that EAL’s proposed contribution policy would influence the investment and contribution policies of the DISCOs, despite EAL’s stated intent to the contrary. This was because the Board, in Decision U99035 for TransAlta and in U99034 for AE directed the DISCOs to flow through TA charges to customers. EAL’s proposal, unlike the policies of TransAlta and AE, does not relate investment level to size of load commitment for larger customers. TransAlta considered that EAL’s proposal would expose other customers to greater costs than if investment were tied to load size. TransAlta submitted that the Board should reject EAL’s investment and contribution proposal and direct EAL to continue under its existing policy. TransAlta considered a load size-related investment policy as appropriate for larger customers.

TransAlta considered that there were other features which were unclear in EAL’s proposal. EAL may require customers to fund amounts over the first $5 million, but the basis for the exercise of that discretion, the form of calculation and the timing of any such funding were all unclear. In reply, TransAlta noted EAL’s argument that contribution on the portion exceeding $5 million “could be between $0 and the total incremental cost of the facilities, depending on how the TA exercises its discretion.” TransAlta considered that amount of discretion amounted to having no real policy at all, particularly given EAL’s opinion on just how far ‘connection facilities’ could be deemed to extend into the grid. TransAlta reiterated its proposal that the Board direct EAL to continue an investment policy driven by the contract level of the load seeking connection.

TransAlta disagreed with TCE’s proposal that customers in the transition period should be allowed to choose the old or new approach. The existing contribution policy determines the
investment / contribution split based on load size, while the new one would not, customers would naturally choose the option which costs them less. This would leave existing customers with increased costs to bear.

TransAlta also disagreed with TCE’s proposal to add a mechanism to relieve the initial customer from connection charges as additional customers come on the line. TransAlta considered that TCE’s proposal would relieve the original customer from payments already set at a level lower than the costs of the connection. EAL’s proposal would only recover a portion of the connection costs caused by the initial customer, less than 50 per cent of the first $5 million, on a present value basis, and TCE’s proposal would see the customer obtain relief from even those levels.

TransAlta considered TCE’s proposal that the Board direct EAL to fund TransAlta for flow-through of Option 10 payments, at least for single customer PODs, to be superfluous. TransAlta stated that its October 4, 1999 Phase II Refiling proposed continuing Option 10 (Option B) payments to current direct-connected customers.

**Position of TCE**

Since TCE considered Rate Schedule STS was not required, TCE recommended Article 9.3 of the Terms and Conditions read as follows:

“9.3 All Load Customers taking service under Rate Schedule DTS shall pay a Customer Contribution if new facility construction or upgrades (the “Facility”) are required to serve the Customer’s Contract Capacity requirements or increases thereto, calculated as follows for each Billing Period, and ...”

TCE considered that there should be a contribution policy for supply similar to that proposed by EAL for DTS customers. TCE considered the provision to pay the contribution in a fixed payment that is a portion of the capital cost and is to be paid over several years to be sound. TCE proposed two refinements to ensure that the policy is more “just, reasonable and fair”. These two areas were pro rata sharing of customer contributions for local connection facilities and a correction to the customer contribution calculation to be consistent with EAL’s proposed 25 per cent allocation to individual customers.

TCE submitted that the proposed contribution policy would be more just, reasonable and fair if it included a mechanism to ensure that customers who trigger a contribution (“Original Customers”) are reimbursed by other customers who arrive shortly thereafter (“Second Customers”) and use the local connection facilities that Original Customers have paid for through customer contributions. TCE suggested a further amendment to article 9.3:

“Where one or more customers attach to the transmission system where they are benefiting from facilities for which a prior customer is paying a contribution to the TA, the other customer or customers will pay a pro rata share of the prior customer’s contributions based on the revenues charged by the TA to each of them. The TA can, as a part of its business practices, use a basis other than revenues to provide a pro rata share of the contributions if such basis is more fair and reasonable.”
TCE submitted that without this proposed amendment to the Terms and Conditions Original Customers may be subsidizing Second Customers who use the facilities that Original Customers have paid for through customer contributions. TCE noted that the transitional tariff had a provision for sharing customer contributions between the Original Customer and the Second Customers. TCE submitted that the provisions in the transitional tariff reflected many years of working experience in dealing with this potentially contentious interface between system and customer costs. TCE submitted that this issue should be dealt with immediately as there is no certainty as to when EAL may file a future application.

TCE supported EAL's determination of 25 per cent NPV as a fair and reasonable policy. This conclusion was based on the evidence of EAL that transmission lines become system related in a short period of time. TCE did not agree with the NPV calculation requested as an undertaking in the hearing. TCE provided a table in argument verifying the NPV calculations. In one instance, TCE noted that when a 10 per cent discount rate is applied to EAL's proposed payment levels of 10 per cent per year for five years, the result is $39.22 per $100 or 39.22 per cent of the capital invested. TCE submitted that the Board should not approve a policy that is equivalent to an NPV of 39.22 per cent as no party has propounded the appropriateness or fairness of such an NPV. Furthermore, the proposed filing resulted, per TCE's calculations, in an implied discount rate of 31.59 per cent. TCE submitted this was inappropriately high. However, TCE noted that EAL's own Exhibit 69 reflected a more reasonable Nominal Discount Rate of 10.09 per cent. TCE rounded this amount to 10 per cent and applied it to either a shortened time period (Case 6 of the table) or a reduced annual percentage (Case 7). TCE recommended the investment policy supported by Case 6 as the TA would receive the funds in a reasonably short period of time (35 months). TCE considered this would circumvent the non-payment issue. TCE considered that either 60 months at a payment level of 6.38 per cent per year or 35 months at a payment level of 10 per cent per year were both acceptable and customers should be given the choice.

TCE supported EAL's policy to allow transitional customers to choose between the proposed and existing contribution policy. TCE considered that it is only fair, just and reasonable to allow these transitional customers to choose the policy that would be most economically sound for them. Imposing an investment policy that could significantly affect the economics of projects already underway could be detrimental to the projects and certainly would be unfair to the transitional customer. TCE requested that the Board stipulate in its Decision that Transitional Customers be able to choose between EAL's proposed investment policy and their existing investment policy.

TCE noted that the harmonization of the TA's investment policy with that of the Distribution Utilities was not a new issue before the Board. TCE considered it an increasingly important issue for customers because of deregulation and the unbundling of costs. Due to the different investment policies, the amount of revenue requirement for essentially similar facilities would be different. For example customers who have foregone higher utility investment levels on the premise that they would continue to receive an ongoing TransAlta Option 10 credit would have no means to continue receiving the credit. TCE noted that EAL has taken the position that this is a DISCO issue but if the Board considers this issue one that EAL should deal with, they would be open to address it. TCE noted that, as a result of Decisions U99034 and U99035, the TA's billings would be passed through to customers via the DISCOs' bills. TCE considered that the

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381 Transcript Vol. 6, pages 1087 to 1088.
TA should have responsibility for ensuring that customers who will be directly affected by the TA’s billings will be treated justly and fairly. TCE requested that the Board clarify EAL’s responsibility in relation to customers that have received lower utility investment based on an expectation that they would receive credits similar to Option 10. TCE submitted that the DISCOs, without an investment policy that reflects the specific investment policy applicable to their customers, would not be able to resolve the matter between them and their customers. TCE submitted that a practical solution would be to direct EAL to provide a revenue requirement to exactly match the Option 10 payments made by TransAlta to Option 10 customers, or at least to Option 10 customers who are the only customer at a point of delivery. TCE requested that the Board direct EAL to address the “Option 10” issue in the refiling and direct EAL to resolve harmonization of its investment policy with the DISCOs within the next six months.

In reply, TCE considered that the defect in the proposed Contribution Policy was the lack of differentiation in its application to different rate classes on the load side. As such, two PODs have the same charges if they have the same energy and demand, regardless of who is served downstream of the POD. TCE noted that EAL proposed reserving “the right to review and assess an additional Customer Contribution for DTS and STS Customers in the event of the capital cost of construction of Facilities exceeding $5 million dollars.” through Article 9.4. TCE considered that EAL should have discretion on projects large enough that they could materially affect the transmission revenue requirements and therefore the tariffs of transmission users. TCE submitted that EAL, as an independent TA, is in a better position to exercise discretion than the DISCO. This is particularly true for larger “end-use” customers served from a single POD. TCE considered that the proposal of AE to discriminate against single end-use customers compared to all other customers is an example of why the TA should hold this discretion, not the DISCO. TCE considered that the TA should not be granted unfettered discretion and the TA’s investment policy should not discriminate against a customer simply because it is a single customer.

With respect to AE and TransAlta’s displeasure with EAL’s proposed contribution policy for local interconnection facilities on the load side, TCE submitted that there was no consensus among the parties to reinstate the previous contribution policy, nor were the Arguments of AE or TransAlta compelling on this matter. TCE considered that the proposals in argument of AE and TransAlta did not deal with major and longstanding concerns regarding “pioneering” and “gold-plating or unused investment”. While perhaps not a perfect solution, TCE agreed with EAL that its policy responded to the “gold-plating” problem by charging a portion of the costs of new transmission, even in cases where no contribution was required. In cases where the investment policy more than covered the cost of the extension relative to the size of the customer, a surplus would remain. This surplus formed the temptation for the customer to “gold-plate” its requirements in order to minimize the amount of surplus (or unused investment).

The proposals of AE and TransAlta did not give a clear, fair and unambiguous mechanism for sharing costs between system and customer costs. Specifically, they clearly discriminated against single large industrial end-use customers, and did not adequately address the “change-in-use” issue. TCE defined this as the case when a relatively simple radial extension required to extend the system to a new customer will likely be used to serve other customers in the future, and is most economically sized to accommodate this eventualty. EAL’s evidence was that some facilities constructed for a particular customer had no subsequent additions for 20 years whereas other facilities which were built, and additional customers came in almost immediately. TCE considered that the existing investment policy based on a per kW charge for new load
inadequately addressed these issues nor did the proposals of AE or TransAlta. TCE submitted the proposals of AE and TransAlta should be rejected in favor of the EAL proposal.

Subject to the changes/modifications to the investment policy, as proposed in TCE’s argument, TCE submitted that the investment policy, as proposed, was fair to all demand customers and customer groups.

**Position of AE**

AE noted that EAL had offered to withdraw both SERP to load and its contribution proposal during the hearing. AE agreed with EAL that both should be rejected. AE submitted that EAL’s own evidence led to the conclusion that 100 per cent of transmission connection costs should be system costs. The exception should be when an extension is attributable to a particular end-use customer. In this case, the determination of customer and system costs would be made based on the circumstances of the extension.

AE submitted that the EU Act defined a delivery substation as a POD so that there will always be one customer at a POD. In reality, some PODs served a single end-use customer and some served multiple users. AE submitted that transmission service to a POD was much like primary distribution service, which was averaged in distribution customers’ rates. Despite this similarity, EAL’s 25/75 proposal differed from the distribution utilities policies. EAL depended on a notional boundary between dedicated and system costs. AE noted that the facts surrounding an expansion is what should determine the amount of a contribution, not an arbitrary allocation.

AE noted EAL’s position that all customers used all of the transmission system. This position also argued for all costs being considered system. Furthermore, EAL’s proposal did not avoid problems over what are customer and system costs. The proposal allowed discretion on the amount over $5 million. Furthermore, the proposal did not ensure that the optimal facilities would be built for the long term.

In reply, AE noted that EAL’s argument was ambiguous as to whether it would withdraw SERP to load. However, all other parties reiterated in Argument their collective opposition to applying SERP to demand customers. AE submitted that EAL should withdraw SERP as it applies to load as it committed during the hearing.

AE considered that, despite EAL’s position to the contrary, SERP to load was discriminatory and based on vintaging or acquired rights. AE noted that EAL maintained that it would be discriminatory to charge SERP to new generators and not to existing generators, yet failed to see the discriminatory aspects of its lead SERP.

AE noted EAL also offered to return to the regular contribution policy, should parties desire. However, AE supported an enhanced customer contribution policy whereby 100 per cent of transmission costs are generally regarded as "system". This was based on EAL’s own evidence that all customers essentially use all of the transmission system. Where the need for an extension is attributable to a particular end-use customer(s), AE submitted that the attribution of costs to "customer" and "system" should be undertaken by the DISCO and not the TA, in accordance with the particular circumstances, which exist at the time. AE submitted that the DISCO and not 382 Tr. page 383
the TA is in the best position to evaluate the appropriate level of a customer contribution, if any. AE considered EAL’s argument regarding this issue to be “contradictory”. EAL maintained that the policy is intended to apply to "easily identifiable" common costs while acknowledges that it was not possible to be precise regarding a customer/system split. AE submitted that the customer/system debate will remain, even if EAL’s proposal were accepted and submitted that the arbitrary nature of EAL’s proposal did not assist in reflecting true cost causation.

AE submitted that EAL’s proposal exposed it to greater risks and costs. AE considered that EAL’s position that its proposed customer contribution policy is "not likely" to change TFO cash flow was not relevant as it is not EAL’s dollars that are at risk as a "forecast risk". AE submitted that EAL was incorrect to characterize the effect of the proposed contribution policy as some kind of forecast risk that ought to have been anticipated and planned for by TFO’s. While EAL suggested that AE can simply deliver the "bad news" to a customer from whom an additional contribution is required, this situation would likely lead to customer complaints and possibly assertions that the previously agreed upon terms are being breached. This concern was also relevant to the "transition" period. AE noted that parties, such as TCE, were urging the Board to allow customers to choose which policy they wish to apply but completely failed to address which party assumed the associated costs and risks. AE submitted that EAL’s proposed contribution policy was impractical and did not reflect the increase in risk to AE.

AE noted that even TCE, despite general support, expressed concern with the policy, as proposed by EAL, and suggested revisions. AE expressed concerns with TCE’s characterization of the TA’s role in relation to DISCOs and their customers. AE submitted that the TA did not have a role in determining the appropriate customer contribution between the DISCO and its customers. Moreover, AE submitted that nothing in these proceedings should bear on an appropriate contribution policy by the DISCO with respect to its customers.

Position of ATCO Power

ATCO Power dismissed EAL’s argument that its customer contribution policy would enhance the competitive market. ATCO Power noted that all of the generators participating in the Coalition agreed that a customer contribution policy is not necessary. These generators were willing to pay the full cost of their interconnections. ATCO Power considered EAL’s proposed contribution policy would send a perverse locational signal to new generators. In effect, those generators who choose the most costly locations will receive the greatest subsidy from the TA.

In reply, ATCO Power described EAL’s proposal as “paternalistic and inevitably controlling” as it required generators to pay 50 per cent of their connection costs. ATCO Power proposed that generators pay 100 per cent of connection charges and this pure economic signal would be an input into all generation developers’ decision making.

Position of the Cities

The Cities noted that EAL’s proposal represented an average increase in the required contribution by customers of more than 50 per cent, based upon the “generous” present value calculations shown in Exhibit 69. In the Cities’ view, this represented the maximum that the TA should be requesting from new load, particularly having regard to principles of rate stability. Furthermore, this represented the limit of balancing of the interests of new and existing capacity.
However, the Cities submitted that the SERP contribution for any increase in capacity including that caused by load growth represented a significant change in the mechanics of applying the contribution policy. In the Cities' opinion, the SERP proposal had two difficulties: it discriminated between load additions on the basis of vintage; and it represented an impermissible locational signal to load contrary to the postage stamp provisions of section 27 of the Electric Utilities Act.

The Cities noted that the first issue was that EAL’s proposal was a modified “last straw” charge, i.e., it essentially charges a portion of the deep system reinforcement required to provide for reliable deep system access. However, as indicated by EAL in evidence, all MWs have the same effect on line requirements regardless of vintage. The Cities submitted that imposing the SERP charge in this fashion unfairly discriminates between loads. This might be justified on the basis of the need to give locational signals to promote economic efficiency but the EU Act precluded such signals with respect to load. The Cities considered that Alberta had approved a policy to not discourage load from locating in any particular part of the province.

The Cities submitted that, because the SERP contribution is a charge that must be paid in order to gain system access, it is a rate contemplated by Section 27 (2)(b) of the Act. The Cities noted the definition of rates contained in Section 17 (a.1), which described rates as including “rates, prices, tolls and charges”. The Cities’ submitted it was clear that Section 27 was not restricted to specific service rates as set out in the rate schedules but included all locational charges that must be paid to gain system access. The Cities noted that EAL conceded that the SERP contribution required from load under Article 9.2 is based upon and varies by location and, therefore, is not permitted under Section 27. In conclusion, the Cities opposed the application of Article 9.2 to load and submitted that it was prohibited by Section 27 of the Electric Utilities Act.

**Position of Medicine Hat**

Medicine Hat stated that there as no doubt that SERP applied to DTS was a rate and not a contribution. This had been admitted by EAL’s witnesses. Furthermore, EAL had stated that the DTS SERP would be applied in the same manner as STS SERP, which would result in differing rates to distribution systems by location. Medicine Hat submitted that this violated S. 27(2) of the EU Act and that this was sufficient reason to reject SERP as applied to the DTS rate.

**Position of IPCAA**

IPCAA noted that important aspects of the proposed contribution policy, its application and interpretation were intended to be expressed in "business practices" that have yet to be established. IPCAA was not opposed in principle to EAL’s proposal but considered that it would be premature for the Board to give final approval to the relevant Terms and Conditions at this time. IPCAA submitted that such approval should be withheld until EAL has fully-developed the anticipated "business practices" and all parties have been afforded sufficient opportunity to consider and comment upon them. Furthermore, IPCAA considered that final approval of a contribution policy required resolving such vexing questions as the sharing of costs of certain types of system upgrades, the obligation of the TA to "deconstrain" transmission paths and the TA’s obligation to serve. IPCAA considered that these issues were not fully examined during the hearing and requested the Board to direct EAL to undertake discussions with its stakeholders as soon as practicable.
Position of the FIRM Customers

The FIRM Customers did not support the requirement that load customers pay contributions, except in unusual circumstances similar to those where transmission contributions are required from load customers. Examples would be loads that cannot reasonably recover their revenue either because they are very expensive or have low load factors or loads where opportunity service is provided. The FIRM Customers submitted that requiring contributions from load customers would not change the amount of money required from end-use customers but it would destroy postage stamp rates for transmission in Alberta by requiring contributions from new loads on a routine basis. The FIRM customers reasoned that EAL’s proposal could raise rates to Alberta ratepayers by moving transmission costs from the transmission rate to the distribution rate. Because the DISCO would earn a return on the contribution and the DISCO rate of return may be higher than the transmission owners’ rate of return, costs would increase.

The FIRM Customers submitted that EAL should develop a capital contribution policy for load customers that is based on revenue. This would form part of the refiling. Such a policy would require a DTS customer to pay a customer capital contribution only for that portion of projected interconnection costs which exceed projected revenues on a present value basis. For other non-firm load services, a 100 per cent contribution to interconnection costs should be required. With respect to EAL’s proposal of a credit for customer-owned facilities, the FIRM Customers submitted that it should only include the revenue-justified portion of such facilities. The FIRM Customers concluded that SERP should not apply to load customers if they are required to make contributions. Furthermore, the FIRM customers considered the postage stamp principle to be applicable to load customers’ rates. Therefore such additional SERP charge/credit were a violation of this principle and not appropriate.

The FIRM Customers supported the EAL capital contribution proposals for supply customers if the 50/50 cost allocation proposal is approved. However if supply customers are allocated less than 50 per cent of embedded wires costs, the FIRM Customers considered supply customers should be responsible for 100 per cent of their interconnection costs to ensure there is not an off loading of costs on to load customers. In addition, the System Access Agreement for STS should contain a provision that, in the event the customer terminates service before 10 years, an exit fee equal to the remaining capital contributions would be required.

The FIRM Customers considered that the issue of responsibility for downstream system upgrades needed to be addressed. If a generator interconnects with the transmission grid and requires a downstream upgrade to relieve congestion, the FIRM Customers considered that the system expansion should be filed with the Board for approval. The Board would determine what share of the expansion would be the responsibility of generation and what share would be the responsibility of the load customers on a case by case basis. The FIRM did not agree with the Coalition’s proposal in amended Exhibit 80 that load customers should only be responsible for system upgrades. The benefits of each upgrade would have to be determined and shared between generators and load customers.
Position of Grande Prairie et al

Grande Prairie et al submitted that the proposal for SERP to load resulted in different rates for the same customer service and, therefore, was contrary to the Act.

Board Findings

_is the load SERP proposal permitted by the EU Act?_  
EAL is the independent, for profit, TA for the Province of Alberta. EAL’s responsibilities are defined in the EU Act. The TA is responsible for the overall administration of the transmission system and is to ensure open, non discriminatory access to transmission facilities. The TA carries out these responsibilities through a number of functions including setting province wide tariffs for system access.

Section 27 requires the TA to prepare its tariff. It reads as follows:

27(1) The Transmission Administrator shall prepare a single tariff setting out

(a) the rates to be charged by the Transmission Administrator for each class of system access service, including rates prepared in accordance with the regulations to be charged pursuant to the arrangements referred to in section 26(c), and

(b) the terms and conditions that apply to each class of system access service provided by the Transmission Administrator to persons connected to the transmission system, including

(i) terms and conditions, prepared in accordance with the regulations, that apply pursuant to the arrangements referred to in section 26(c), and

(ii) standards and requirements set under section 26(d).

27(2) The rates set out in the tariff

(a) must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Transmission Administrator, and

(b) must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system.

27(3) Rates are not unjust or unreasonable simply because they are prepared taking into account subsection (2)(b).

“Tariff” is defined in s.17(b) as follows:

s.17(b) “tariff” means a document that sets out

(i) rates, and

(ii) applicable terms and conditions;

“Rates” are defined in s.17(a.2) as follows:

(a.2) “rates” means prices, rates, tolls and charges that apply to service provided by an electric utility or the Transmission Administrator;

Finally “terms and conditions” are defined in s.17(c) as follows:
s.17(c) “terms and conditions” means the standards, classifications, regulations, practices, measures and terms and conditions that apply to service provided by an electric utility or the Transmission Administrator.

It is a well known principle of statutory interpretation that words of a statute are to be given their ordinary meaning unless the context requires otherwise. The EU Act requires that rates for owners of electric distribution systems “...must not be different ... as a result of the location of those systems on the transmission system”. EAL has proposed a tariff with hybrid pricing. In the “rate” portion of the tariff, it has proposed a system wide or postage stamp rate that recovers system capacity costs. In the T&C part of the tariff it has proposed a customer contribution. A portion of the customer contribution attempts to reflect the costs or benefits associated with the geographic location of the load. In this way EAL’s pricing attempts to recognize and assign costs or credits to those load customers that impose costs or provide benefits to the system.

EAL attempts to differentiate between what is a rate and what is a T&C and argues that a T&C can have a financial implication without becoming a rate. It may be reasonably concluded however, that the ordinary meaning of “rates” would include all financial payments customers are charged for service provided by the TA. For purposes of this Decision, that question need not be pursued.

The over arching requirement in the EU Act for postage stamp rates does not allow for the implementation of a hybrid pricing structure which differentiates between load customers based on their location on the system. EAL cited the case of Decision U98060 involving Northwestern Utilities Ltd. as an example of where the Board has approved a rate and conditions that might include disparate customer contributions. EAL readily admitted that this case is distinguishable. The most important difference is that, in the case of the TA, postage stamp rates are mandated and in the gas case cited, they are not. The EU Act expressly provides that owners of electric distribution systems pay the same price for transmission service regardless of their location on the transmission system. Pricing of transmission that includes contributions based on costs or benefits caused by customer location will result in prices for service that are different as a result of location. In the view of the Board, this offends Section 27(2)(b) and must be rejected. Accordingly, the location-based SERP portion of customer contributions proposed by EAL is denied.

**EAL’s Proposed Contribution Policy for Load Customers**

The proposals for load contributions range from AE and the FIRM Customers’ position that load customers should not pay customer contributions to EAL’s position that, in some circumstances, a contribution of 100 per cent may be required. The Board considers that customer contributions are suitable in circumstances where service to a customer may impose costs on other customers for which they should not be responsible. An appropriate contribution policy therefore provides a suitable balance to an unlimited obligation to serve by imposing economic discipline on siting decisions. It transfers the economic burden of connection of new customers from the utility and its existing customers to the new customer. In other words, it exerts some of the discipline of the utility’s economics on the economic decision-making of the customer. The Board considers that customer contributions should relate only to the local connection costs of the system expansion. The deep system costs of expansion are properly the responsibility of all customers, form part of the utility’s revenue requirement and should be recovered from all customers through rates.
Concerning the size of the contribution, the Board considers that, as the DISCOs' transmission utility, the TA's investment policies should be as consistent as possible with those of the DISCO so that the TA's costs flow through efficiently to end-users. In this respect, the Board notes that the DISCOs employ a revenue-based system to determine the amount of investment that the project will support, with 100 per cent contribution above that amount. The DISCOs require contributions only on the customer connection with the “backbone” system costs borne by all DISCO customers, consistent with the Board's findings above. The Board considers that with a contribution that is more consistent with that of the DISCOs, issues surrounding EAL's contribution policy such as the Unused Investment Credit and refunding customer contributions as additional customers are connected will be resolved.

Therefore, the Board directs EAL, in its refiling, to develop its contribution policy based on the excess of project cost over supporting revenue for the connection of load costs for customers. The Board agrees with TransAlta that the contract level of the load seeking connection should drive the investment policy. EAL may express this in terms of investment per kW if convenience directs.

The Board notes EAL's agreement that Article 9 could be amended to make it more fair to the first customer that has paid the contribution, when a second customer comes along and uses the facilities to which the first has provided a cost contribution. The Board supports EAL's submission that such a procedure could be implemented as a business practice following stakeholder consultations to review the various mechanisms by which this could be achieved.

Other contribution-related policies should be harmonized with those of the DISCOs as much as possible to reduce interface problems between the DISCOs' systems and the transmission system. The Board considers that such a contribution policy would minimize any transition problems associated with the tariff. Accordingly, the Board does not agree with TCE's request that the Board stipulate in its Decision that transitional customers be able to choose between EAL's proposed investment policy and their existing investment policy. The Board considers that any change to EAL's investment policy should be implemented on a prospective basis.

**EAL's Proposed Contribution Policy for Supply Customers**

In addition to placing the same form of economic discipline on supply customers’ decisions as load customers, an appropriate contribution policy should treat new generation fairly compared to existing generation. In Section 8, the Board has confirmed that it is appropriate to charge existing generation for its connection costs. In addition, generation representatives such as ATCO Power and IPPSA proposed that new generation pay 100 per cent of connection costs. Incorporating connection costs into the economic decisions concerning new generation plant will provide effective cost signals to proposed new projects.

The Board, in Section 13, found that supply and loads are responsible to bear the cost of bulk system reliability upgrades by way of the STS rate for generators and the DTS rate for loads. The Board also directed EAL to develop business practices that deal with the costs of commercial upgrades to the transmission system resulting from the connection of new supply customers.

The Board considers that its findings will result in fair treatment of new and existing generation and similar treatment between supply and load. This is consistent with the Board's findings on allocation of embedded costs between supply and load.
Accordingly, the Board directs EAL, in its filing, to develop a contribution policy which will result in new supply customers paying for 100 per cent of local connection costs with deep bulk system costs recovered through STS and DTS rates. The Board, in Section 13, noted that the guidelines provided by Dr. Tabors\textsuperscript{383} have some merit in distinguishing between the local connection and the backbone system. The Board directs EAL to provide similar policies respecting refunding of contributions, unused investment credits, exit provisions, etc. as applied to load customers for supply customers.

**EAL’s Proposed Contribution Policy for Opportunity Customers**

The Board approves EAL’s proposal for 100 per cent contribution towards incremental facilities required for the required level of opportunity service. This is an incremental service and the TA should not be planning and building facilities to accommodate opportunity service.

16.2 Dispute Resolution

In Section 7.0, Article 16 of its application, EAL included the following clause with respect to dispute resolution:

> If the Dispute has not been resolved within 30 days after referral to the senior officers, either the TA or the Customer may require, by written notice, that the Dispute be resolved through arbitration. The parties shall appoint a mutually satisfactory arbitrator within 10 days of the notice to resolve the Dispute through arbitration. In the event that the parties cannot agree on a single arbitrator within 10 days, each party shall appoint an arbitrator with 10 days thereafter by written notice, and the two arbitrators shall together appoint a third arbitrator. In the event that a tribunal is required, the third arbitrator shall be appointed within 20 days of written notice for arbitration. The arbitrator or tribunal shall render a decision within 30 days of the last appointment. The arbitration shall be conducted in accordance with the Arbitration Act (Alberta), as amended from time to time. In the event of a conflict between these Terms and Conditions and the Arbitration Act, these Terms and Conditions shall prevail.\textsuperscript{397}

**Position of EAL**

EAL stated that its customers had adequate protection from any arbitrary exercise of discretion by the TA. This protection included the TA’s independence (the TA has no financial interest in how the T&C apply), the T&C dispute resolution provisions\textsuperscript{384}, and ultimately the option to complain to the Board. The T&C could also be modified in the event of a problem.

EAL submitted that the discretion granted to the TA by the T&C was reasonable in the circumstances and should be approved.

**Position of the FIRM Customers**

The FIRM Customers indicated that, under Article 16.2 of EAL’s T&C, if a dispute remained unresolved for 30 days after being submitted to the senior officers of the TA and the respective customer, then either party might require it be resolved by arbitration. It noted that the procedure proposed by EAL was to have each party to the dispute try and agree on an arbitrator. If the

\textsuperscript{383} Exhibit 80  
\textsuperscript{384} T&C Article 16.
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generators in the installation of the PSS or AVR that are found by the Board to be imprudent in any EAL tariff proceeding will be reimbursed to the TA by the party receiving the payment.

- If the excitation system of an existing regulated or unregulated generator to which Article 5.2 does not apply is rebuilt or replaced, the new excitation system must be suitable for PSS, and a PSS/AVR must be installed.

The Board notes that further revisions may be required to Article 5 depending on the Board's Decision, at a future GTA, respecting whether the costs of required PSS/AVR equipment should be recovered from the generator requiring the retrofit or as a system support cost from all supply and demand customers.

4.4 T&C Article 9.1

EAL submitted the following wording for Article 9.1:

In considering requests to serve a new POD or POS or to increase the capacity of, or improve or maintain the existing standard of system access service at an existing POD or POS, the TA, in its sole discretion, will determine the appropriate means of delivering the requested service and the customer-related costs (borne by the customer subject to this Article 9) and the system-related costs (costs borne by all customers) incurred to provide the service.

Views of TCE

TransCanada Energy Ltd. (TCE) submitted that Article 9.1 had been substantially redrafted and the new draft has not had the benefit of stakeholder review. TCE suggested that the TA is in a better position to exercise discretion than the DISCOs. However, this discretion cannot be unfettered. The broad “sole discretion” sought by the TA is unacceptable. TCE pointed out that the Board noted that the guidelines provided by Dr. Tabors (Exhibit 80) have some merit in distinguishing between the local connection and backbone system. The TA’s discretion should be tied to guidelines and business practices to be developed with stakeholders, and filed with the Board as soon as possible.

Views of AE

AE questioned the inclusion of the phrase “in its sole discretion” in this clause. AE submitted that parties should have recourse to the Board if they disagree with the TA’s allocation. AE submitted that this phrase should be deleted.

Views of ENMAX

ENMAX stated that EAL had inserted as the triggering events that may give rise to a customer contribution,

...requests to serve a new POD or POS or to increase the capacity of, or improve or maintain the existing standard of system access service at an existing POD or POS...” (emphasis added).
ENMAX submitted it was inappropriate to consider charging existing customers additional customer contributions simply to maintain existing levels of service in the event new customers are attached. ENMAX argued that, conceptually, customer contributions relate to new incremental service (whether provided to new or existing customers). Therefore, any portion of connection costs not recouped from the customer requesting incremental service is to be recovered as transmission costs from all customers, not just the other customers at that particular POS or POD.

ENMAX therefore requested the Board to direct EAL to remove all reference to the maintenance of existing standards of system access service from Article 9.1.

Views of EAL

AE objected to the term “sole discretion” with reference to the determination of the most appropriate way to serve a new or existing POD or PODs, and costs as customer-related and system-related. EAL submitted that the TA will solicit input from the relevant DISCO, but ultimately the TA is in the best position to make this allocation, and the phrase “in its sole discretion” is appropriate. EAL noted that parties have recourse to the Board if they disagree with the TA’s allocation.

EAL also noted that, in consultation with its stakeholders, EAL intends to establish business practices pertaining to the allocation of costs to the customer-related and system-related categories, as well as costs related to commercial or reliability upgrades. These practices will be reviewed in the next GTA.

EAL noted it was not presently its intent to classify such costs related to the maintenance of existing standards of system access service as customer-related. EAL stated that it is currently reviewing its customer contribution philosophy in its entirety, part of which is to establish meaningful criteria for the classification of costs as system-related, customer-related, and commercial. At the time of its refiling, EAL did not wish to preclude or prejudice the outcome of these deliberations, or foreclose on the possibility that some portion of the cost of system reinforcements necessary to maintain the existing standard of system access service for a point of supply may conceivably be allocated as a customer-related or commercial cost.

Views of the Board

The Board considers that the phrase “in its sole discretion” is appropriate given the responsibilities of the TA in this matter, and the fact that parties have recourse to the Board if they disagree with the TA’s allocation of customer-related and system-related costs.

The Board accepts EAL’s position that it is not presently contemplating classifying such costs as customer-related. In view of EAL’s position, the Board agrees with ENMAX that the words “or maintain the existing standard of system access service” should be deleted until such time as EAL firms up its customer contribution policy. The Board considers the appropriate time for such words, if they are necessary, is after EAL’s review and Board final approval of its customer
contribution policy. Accordingly, the Board directs EAL, in its Second Refiling, to remove the words “or maintain the existing standard of system access service” from Article 9.1 of its T&C.

4.5 **T&C Article 9.3**

EAL submitted the following wording for Article 9.3:

> The capital credit pursuant to paragraph 9.2 will be determined according to the following table in which the “minimum term” is the period commencing no earlier than the completion of the necessary facilities pursuant to paragraph 9.1.

<table>
<thead>
<tr>
<th>Capital Credit per kW of Contract Capacity</th>
<th>Minimum Term</th>
</tr>
</thead>
<tbody>
<tr>
<td>$115</td>
<td>5 years</td>
</tr>
<tr>
<td>$200</td>
<td>10 years</td>
</tr>
<tr>
<td>$265</td>
<td>15 years</td>
</tr>
<tr>
<td>$310</td>
<td>20 years</td>
</tr>
</tbody>
</table>

The Capital Credit available will not exceed the customer-related cost for any individual POD.

**Views of TCE**

TCE noted that the TA’s proposed policy is close to that of AE’s, but very different from that of TransAlta’s DISCO investment policy (approximately twice that of TransAlta’s at $167/kW and no refunding of unused investment). TCE argued that to accept the TA’s proposal would not meet the objective of the Board’s directions and would result, by default, in a major financial loss to TransAlta’s POD-connected customers. To correct this problem, the Board could direct the TA to have an investment policy that matches TransAlta’s for PODs located in TransAlta’s service area. Alternatively, the Board could direct the TA to make a one time true-up of capital investment for TransAlta’s POD-connected customers to place them on a level playing field with other TA served PODs. TCE preferred the latter course of action, as it results in a long-term solution to this issue.

**Views of EAL**

EAL noted that the investment policy in its refiling was a continuation of the TA investment policy that has coexisted with the investment policies of the DISCOs since it was first approved by the Board in the GRIDCO tariff. EAL did not believe that the Board intended EAL to implement a contribution policy that was perfectly consistent with all aspects of the investment policies of all DISCOs, nor did EAL believe that drafting such an investment policy was possible.

EAL stated that the investment policy included in the refiling complies with the Board direction. The recommendation of TCE that the TA implement a separate investment policy for
TransAlta’s service area or make payments directly to TransAlta’s customers creates unnecessary complexity and increases costs for other customers for the benefit of TransAlta’s Option 10 customers. EAL noted that TCE’s recommendation repeats the position taken by TCE in its argument (see Decision 2000-1, Pages 15 to 16).

EAL further noted that the investment policy in the refiling is an interim measure only. The issue will be further addressed in the next GTA and no doubt in future GTAs. All interested parties will have an opportunity for input at that time.

**Views of the Board**

The Board notes that it will be difficult to draft and implement a contribution policy that is consistent with all aspects of the investment policies of all DISCOs. The Board also notes that the investment policy is an interim measure and will be addressed in the next GTA, as suggested by EAL.

Accordingly, the Board does not accept, at this time, TCE’s request that the Board direct the TA to have an investment policy that matches TransAlta’s for PODs located in TransAlta’s service area. Additionally, the Board does not accept, at this time, TCE’s request that the Board direct the TA to make a one time true-up of capital investment for TransAlta’s POD-connected customers to place them on a level playing field with other TA served PODs. The Board considers that these are matters to be considered by EAL and all stakeholders in the review of the TA’s customer contribution policy.

**4.6 T&C Articles 9.6, 9.7, 9.8, and 9.9**

EAL proposed the following wording for Articles 9.6, 9.7, 9.8, and 9.9:

9.6 Any Customer Contribution that is required to be paid to the TA must be paid prior to the TA initiating procurement of the required facilities.

9.7 The cost estimate used in the calculation of customer-related costs will be based upon assumptions with respect to the method of construction and the routing of the facilities, including but not limited to approvals and rights of way required to serve the Customer in accordance with the Customer’s request.

In the sole opinion of the TA, where a request for service is changed by a Customer, or the assumed timing, method of construction, or routing of facilities, are changed for reasons beyond the reasonable control of the TA, or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) Subject to (b), where there is an increase in the Customer Contributions, this amount is immediately payable to the TA, or

(b) Where feasible, the Customer or the TA may modify the terms of the contract to adjust Contract Capacity or the term of the contract.

9.8 The Customer shall, in such case as contemplated under paragraph 9.7, have the right to cancel the request for service by paying to the TA, and or the TFO, all costs then incurred or required to be incurred to discharge the TA, and or TFO, of all obligations and satisfactorily cancel the request for System Access Service.
9.9 In the event that facilities installed to provide System Access Service to the Customer are utilized by the TA to provide System Access Service to other Customers, the TA will, in its discretion, refund to the Customer affected such portion of a Customer made capital contribution, as the TA considers equitable after accounting for anticipated use made of the said facilities in serving other Customers and such other circumstances that the TA considers relevant and substantial.

**Views of TCE**

TCE noted that the present wording of Article 9.6 of the refiled T&C indicates that any customer contribution would be required to be paid to the TA “prior to the TA initiating procurement of the required facilities”. The time period between the initial discussions with the TA and the commissioning of the facilities could be considerable, and accordingly an upfront payment of the customer contribution could be too onerous for some customers and result in a barrier to certain projects. As such, TCE recommended that Article 9.6 be revised to be consistent with the existing process that exists for customer contributions—that customer contributions be paid “prior to the commissioning of the facilities”. Also, Article 9.6 should allow for back-out provisions (back-out contracts).

Furthermore, TCE proposed that to ensure consistency and in order for customers to understand their costs and risks, the TA should be required, pursuant to Articles 9.6 and 9.8, to provide a schedule of payments and obligations, along with monthly updates. TCE offered that should the Board find merit in these suggestions, then it would be reasonable to modify Article 9.7 such that the TA (or appropriately appointed TFO) would be held to the estimates, obligations, and time schedules that they prepared for customers. TCE argued that the proposed wording of Article 9.7 transfers all risk of the TA’s estimates, for which they are paid, to customers who have no control of the estimates, construction process, or customer contribution calculation. A transmission project delay could have substantially negative impacts on new plants (POD customers) or generators (POS customers). Customers of the TA need pricing and timing certainty.

**Views of IPPSA**

The Independent Power Producers Society of Alberta (IPPSA) agreed that there was a need to refund capital contributions to new customers when they emerge and make use of existing facilities that were paid for via capital contributions of an earlier customer. IPPSA noted that this was a particularly important issue for generators, who paid the entire cost of interconnection and who would be disadvantaged if no such provision existed. However, IPPSA noted that the proposed Article 9.9 was too vague to be useful. IPPSA submitted that EAL should provide a more detailed description of the method it intends to use to calculate refunds, and the criteria upon which the TA proposed to exercise its discretion to refund capital contributions.

**Views of EAL**

EAL stated that customer contributions were to be paid prior to the procurement of facilities to ensure payment from customers, regardless of the customer’s credit rating. EAL further acknowledged that, in some cases, a customer with a strong credit rating who has signed a
construction commitment agreement could request that the customer contribution payments be staged to match construction expenditures by the TFO. The agreement to stage the customer contribution, or make the payment just prior to the commissioning date, could only be made with the agreement of the TFO and EAL. An exception to Article 9.6 would only be made with respect to large projects that take months to construct. Each case would be dealt with on an individual exception basis. Approval of an exception by the chief financial officer of the TFO and EAL would be required.

With respect to TCE's request that Article 9.6 be amended to "allow for backout provisions (backout contracts)", EAL stated that prior to direct assignment of a project by EAL to a TFO, the customer is required to sign a construction commitment agreement. Appendix A of the agreement sets out a monthly schedule of maximum expenditures for which the customer is responsible if the customer cancels the project. Appendix A is updated, as required, as the project proceeds. The construction commitment agreement is terminated when a system access agreement is signed and customer contributions have been paid in full.

With respect to TCE's suggestion that Article 9.7 of the T&C should be modified to give customers "pricing and timing certainty", EAL stated its belief that such a modification was unnecessary. EAL noted that Article 9.7 gives the customer as much pricing certainty as possible. The TA or the TFO prepare a cost estimate for the transmission facilities required to serve the customer, and that estimate forms part of the facilities application to the Board if the customer decides to proceed with the project. Once the facilities are approved, the cost estimate does not change unless the customer modifies the project or there is an occurrence beyond the reasonable control of the TA or the TFO.

EAL noted that at Page 271 of Decision 2000-1 the Board stated as follows:

The Board notes EAL's agreement that Article 9 could be amended to make it more fair to the first customer that has paid the contribution, when a second customer comes along and uses the facilities to which the first has provided a cost contribution.

EAL further noted that Article 9.9 of the refiled T&C provided the TA with the discretion, in appropriate circumstances, to reallocate costs between the first and subsequent customers.

EAL further noted that at Page 271 the Board went on to state:

The Board supports EAL's submission that such a procedure could be implemented as a business practice following stakeholder consultations to review the various mechanisms by which this could be achieved.

EAL proposed to implement such a business practice after stakeholder consultations. Further details or criteria for the exercise of the TA's discretion under Article 9.9 will be part of the business practice.

In the interim period before the business practice is fully developed, EAL will consult with affected customers if the issue addressed by Article 9.9 should arise.
Views of the Board

The Board agrees with the position of EAL concerning Articles 9.7, 9.8, and 9.9, and finds that the terms and conditions of these Articles are sufficient and necessary as detailed in the refiling and that no amendments or changes are necessary.

With respect to Article 9.6, the Board accepts EAL’s position that in some cases customer contribution payments may be staged to match construction expenditures by the TFO. The Board accepts that it would be unfair, particularly on large projects that may last several months, for the TFO to have to pay all monies prior to the TA making any payments. This could cause undue financial hardship on the TFO.

The Board is also mindful that the TA would not want to be in a position to have to invoke Rider B as a consequence of either a cash flow surplus or shortfall due to mis-matched customer contribution payments and construction expenditures by the TA.

Accordingly, the Board directs EAL, in its Second Refiling, to make the following amendment to Article 9.6:

9.6 Any Customer Contribution that is required to be paid to the TA must be paid prior to the TA initiating procurement of the required facilities unless other credit arrangements are made, acceptable to the TA.

4.7 T&C Article 10.1

EAL proposed the following wording for Article 10.1:

After Commissioning, the TA will issue a Statement of Account for System Access Service to each Customer no later than fifteen (15) Business Days after the end of each Billing Period. The TA will determine the payment required and funds owed by each Customer for System Access Service at each POD and POS, as applicable, using available Metered Demand, Metered Energy or Energy Transfer data, as applicable, to calculate charges and any applicable credits. The TA may deduct amounts owing by the TA to the Customer or its Affiliates under other agreements between the TA and the Customer or its Affiliates from the Statement of Accounts.

Views of AE

AE submitted that Article 10.1 was totally unacceptable. AE submitted that the TA must be required to deal separately with each party with whom it has any type of commercial arrangement.

Views of EAL

EAL noted that AE took exception to Article 10 of EAL’s T&C. Article 10 of the T&C was included in the EAL T&C considered in the hearing and was not modified by the refiling. AE had ample opportunity to address its concerns during the hearing and should not be permitted to use the refiling process for that purpose. No modification to Article 10 is required.
DECISION 2001-6

ESBI ALBERTA LTD.

2001 GENERAL RATE APPLICATION
PART D: CUSTOMER CONTRIBUTION POLICY
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1 INTRODUCTION

The Alberta Energy and Utilities Board (the Board or EUB) received an application dated May 18, 2000 from ESBI Alberta Ltd. (EAL, Transmission Administrator (TA) or the Applicant) respecting a general tariff application for the 2001 test year (the Application). The Application was made pursuant to Sections 27(1) and 49(2) of the Electric Utilities Act (EU Act) and requested approval of a revenue requirement for 2001 (the Phase I matters) and a rate design, including a revised customer contribution policy (the Phase II matters). EAL indicated that it would prefer receiving a decision on its proposed customer contribution policy on an expedited basis so as to assist potential demand customers contemplating investments in Alberta.

This Decision is Part D of the matters the Board has dealt with to date pertaining to EAL’s application. Decision 2000-39, dealing with Appendix E, was Part A, Decision 2000-57, dealing with the approval of interim rates was Part B, and Decision 2000-87, dealing with interim approval of Article 24 and mislabeled as Part A, was Part C.

In expectation of the filing, a Notice of Hearing was published in major daily newspapers in Alberta. Notice was also served simultaneously on interested parties by facsimile and email. The notice included a proposed schedule of dates for the proceeding.

The Hearing was held at the Board’s offices in Calgary from September 28, 2000 through to November 2, 2000 for a total of 18 hearing days. The Application was heard by N. W. MacDonald, P. Eng., A. J. Berg, P. Eng., and R. G. Lock, P. Eng. sitting as the Board Panel.

During the hearing the Board indicated that it was willing to receive argument and reply respecting the contribution policy issue on an expedited manner and deal with this issue as a separate module.

The Board subsequently received written argument, with respect to the contribution policy, on November 22, 2000 and written reply on November 30, 2000. Having heard the evidence and reviewed the arguments of the interested parties, the Board sets out its Decision with reasons, with respect to the customer contribution policy.

As a result of this Decision, it will be necessary for EAL to refile its proposed customer contribution policy.
The following parties were registered for the proceedings:

- Aboriginal Communities
- Alberta Association of Municipal Districts and Counties (AAMDC)
- Alberta Cogenerators Council (ACC)
- Alberta Federation of REAs Ltd. (REAs)
- Alberta Irrigation Projects Association (AIPA)
- Alberta Urban Municipalities Association (AUMA)
- Amoco Energy Management Services Canada (Amoco)
- ATCO Electric (AE)
- ATCO Power (ATCO Power)
- British Columbia Hydro and Power Authority
- British Columbia Power Exchange Corporation (POWEREX)
- Calpine Corporation (Calpine)
- Canadian Forest Products Limited (Canadian Forest)
- Cities of Lethbridge and Red Deer (the Cities)
- City of Calgary (Calgary)
- City of Medicine Hat (Medicine Hat)
- Consumer Coalition of Alberta (CCA)
- Duke Energy Marketing (Duke)
- Enron Canada Corp. (Enron)
- ENMAX Corporation (ENMAX)
- EPCOR Utilities Inc. (EPCOR)
- ESBI Alberta Ltd. (EAL)
- the FIRM Customers (composed of AUMA, AAMDC, Alberta Federation of REAs Ltd., CCA, AIPA, and PICA) (FIRM)
- Fording Coal Limited (Fording)
- Independent Power Producers Society of Alberta (IPSAA)
- Industrial Power Consumers Association of Alberta (IPCAA)
- Public Institutional Consumers of Alberta (PICA)
- TransCanada Energy Ltd. (TCE)
- TransAlta Utilities Corporation (TransAlta)
- Utilicorp Networks Canada (Alberta) (UNC)

A list of the appearances of the individual counsel and witnesses is provided as Appendix 1 to this decision.

2 VIEWS OF THE INTERVENERS

2.1 Views of EAL

EAL’s Customer Contribution Policy was contained in Article 9 of its Terms & Conditions of Service, Tab 2 of the Application. Further detail and explanation of the proposed policy was located at section 8.2 of Tab 8 of the Application.
EAL claimed that the application of their proposed formula, combined with the simplified system definition was expected to result in an overall level of customer contributions comparable with previous utility policies. EAL also claimed that these results would be obtained with more predictability and objectivity from the customers’ perspective.

In Article 9.1, EAL stated that in considering requests for service at a new Point of Delivery (POD) or Point of Supply (POS) or to increase the capacity of, or improve the existing standard of service at an existing POD or POS, the Transmission Administrator (TA) would determine the appropriate means of delivering the requested service. The TA would also determine the system-related costs, the Customer-related costs and the Customer contribution subject to Article 9.

In Article 9.2, EAL stated that any cost of providing new or increased levels of service associated with non-radial elements of the System as it existed, or as it was planned, would be classified as system related costs and rolled into the Tariff. All radial costs would be classified as customer related costs.

Article 9.3 contained the formula to be used in determining the portion of customer related costs to be paid by the customer as a customer contribution. The formula was as follows:

(a) Customer contribution = customer related costs minus the Roll-in Ceiling.
(b) Roll-in Ceiling = Commitment Term Amount plus the Revenue Related Amount.
(c) Commitment Term Amount = $2 million dollars for every five (5) year commitment term after the first five year commitment term. A commitment term is a five year period within which the Customer commits to maintain its Contract Capacity at or above its initial Contract Capacity.
(d) Revenue Related Amount = three times the incremental annual revenue from the new or expanded service.

The maximum number of commitment terms is four, resulting in a maximum commitment amount of $6 million. If the result of the Customer contribution calculation were negative, no payment would be made to the Customer.

Article 9.4 stated that, if the TA determined that a request for service would be more economically satisfied by a distribution level extension, by isolated generation, or primarily represents a shift of demand from an existing POD, then the Roll-in Ceiling would be zero.

Article 9.5 stated that in all cases the Roll-in Ceiling for Customers requiring service under Rate Schedules STS, DOS, Import Service and Export Service would be zero.

At section 8.2.1 of Tab 8, EAL explained that, to ensure efficient development, especially in the area of transmission versus distribution decisions, the TA would conduct a preliminary review of all requests for new extensions.

The purpose of this review would be to determine if an acceptable level of service could be provided by a lower cost distribution extension (or in some cases, from isolated or islanded self-
generation). If the TA found this to be probable, then the Roll-In Ceiling would be set to zero. The onus would then be on the applicant to demonstrate that an acceptable service level could not be provided by a distribution extension.

The Roll-In Ceiling would also be zero when the new delivery point predominantly represents a transfer of load from an existing delivery point. If the customer could demonstrate that the distribution or isolated generation alternatives represent a cost that is at least equivalent to the transmission extension, then the Roll-In Ceiling would remain available.

At section 8.2.2, EAL stated that there would be no payment of negative customer contributions, payments where the Roll-In Ceiling exceeded the customer related cost of an extension. Only where extension costs exceeded an acceptable roll-in level would the customer face a contribution. Making payments to customers whose extensions cost less than the Roll-In Ceiling defeated the system wide averaging of the tariff. Customers receiving such payments as a monthly credit would be charged less than the postage stamp tariff. This would reasonably be considered a rate difference by virtue of geographic location contravening the Electric Utilities Act. Negative customer contribution payments also result in higher costs for other system customers, either as increased rates, increased frequency and level of contributions for new extensions, or both.

Article 9.10 dealt with the issue of contribution rebalancing, a situation that occurs when the TA constructs facilities to serve one customer, collects a customer contribution, and then uses the same facilities to serve other customers at a later date. In particular, Article 9.10 stated that, if the TA installed facilities to provide System Access Service to a Customer who was assessed a Customer contribution. The Article further explained that if the same facilities were used within ten (10) years of energization of the original Customer to serve other Customers, the TA would adjust the original Customer’s contribution and assess the new Customers contribution on the basis of the following:

(a) the commitment term of the original and new Customers;
(b) the Revenue Related Amount of the original and new Customers;
(c) the extent of shared facilities;
(d) Contract Capacity of the original and new Customers; and
(e) The time interval between the energization of the original and the new Customers.

If the interval described in (e) exceeded five years, under EAL’s proposed policy, then the adjustment to the original Customer’s contribution would be determined on a declining balance basis with the balance being zero in the tenth (10th) year. An adjustment as described above would also apply to situations where the TA subsequently deemed that all or part of an original Customer’s interconnection facilities to have become system related.

In section 8.2.3 at Tab 8, EAL explained that ten years was a reasonable time frame from a planning and administrative perspective to maintain and perform the necessary calculations. Rebalancing would be based on a recalculation of the original contributions, had the presence of the subsequent customers been originally forecast taking into account the extent of shared facilities and with appropriate adjustments for the time value of money and Transmission
Facility Owner (TFO) revenue requirement changes. In order to prevent any discontinuity issues, the available refund to the original customer was proposed to be linearly discounted to zero between the sixth and tenth year.

In argument, EAL stated that its contribution policy was intended to deal with the new commercial interface introduced by the EU Act between the transmission and the distribution systems that did not exist with the integrated utilities.

EAL stated that the TA’s contribution policy is a vital means of providing the appropriate price signals at that interface. Whether a $10 million transmission system extension will serve a single end user or a large group of end users, the cost impact on the TA’s other customers is the same from the perspective of the transmission system. EAL argued that applying the contribution policy and assessing a customer contribution against a DISCO for a new point of delivery sends the right economic signal and is fair.

EAL submitted that if the DISCO is required to pay a customer contribution for a multi-customer POD, the DISCO has a number of options for fairly distributing those costs among its customers. The DISCO could allocate the cost of the contribution to one or more customers behind the POD, to all customers behind the POD or to all customers on the distribution system.

EAL considered the AE “wholesale customer” and “end-use customer” approach was inappropriate. EAL characterized AE’s position as “DISCOs should not be subject to the contribution policy”. In any event, the introduction of customer choice on 1 January 2001 will essentially remove the distinction between wholesale and retail customers from the perspective of the distribution utility (subject to the RROT).

EAL considered that the TA is in the best position to apply the transmission contribution policy. DISCOs give the TA all information required for planning transmission facilities, including the “behind the POD” data on load growth, type of load and number of customers.

If a material change in the data came to a DISCO’s attention, it would be brought to the attention of the TA as a matter of course. AE confirmed that this process leads to the design of efficient, cost-effective facilities.

EAL considered that the ultimate decision with respect to the imposition or the amount of a customer contribution, whether for a single-customer POD or a multi-customer POD remains with the TA.

EAL anticipated that in the ordinary course, there would be discussion between the TA and its customer. Reducing the amount of discretion involved in the customer versus system determination should assist in avoiding lengthy debates between the TA and its customer with respect to application of the contribution policy.

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1 Tr. p.2537.
2 Tr. p. 3120 ff. and EAL-AEE-3
However, in EAL’s view, the application of the contribution policy is not a joint TA – DISCO decision. The DISCO does not have a veto. The DISCO has the same rights as any other customer and no more. For purposes of the contribution policy, the TA is in the same position relative to the DISCO as the DISCO would be relative to its distribution customers. EAL does not expect that distribution customers have a veto on the customer contributions charged by the DISCO.

EAL noted that the Board directed EAL in Decision 2000-1 to develop a contribution policy based on the excess of project cost over supporting revenue for the connection of load costs for customers. In that Decision, the Board also directed that the contribution policy “be harmonized with those of the DISCOs as much as possible.” EAL had extensive consultations with stakeholders with a view to developing a contribution policy that would address the Board’s directions and stakeholders concerns.

EAL noted these consultations were summarized at Tab 9 of the Application, pages 9 of 17 to 14 of 17. EAL submitted that it was clear that most stakeholders sought greater certainty as to when a contribution would be required and how it would be calculated.

In particular, EAL noted that many stakeholders were looking for increased objectivity and reduced discretion in the determination of whether a facility was to be “system” or “customer”. Objectivity in the classification process would prevent what many stakeholders viewed to be arbitrary decisions based on rate base, service area and retail positioning considerations and would prevent discrimination between industrial and other customers when decisions relating to system classifications were made.

EAL addressed this concern by defining customer facilities in terms of “radial” facilities and proposing the contribution formula in Article 9.3. EAL submitted that the purpose of these provisions is to reduce the discretionary aspects of the decision.

EAL admitted that its approach would not eliminate the need for discretion. EAL submitted that reliance on the radial definition and the Roll-in Ceiling was a marked improvement and was preferable to the current situation. EAL expected that exercise of its discretion would be the exception, rather than the rule. EAL considered that the approach of AE would require the exercise of an extraordinary amount of discretion in every case.

Stakeholders at the consultations raised the issue of fairness. Stakeholders expressed the desire to balance the requirement to provide service to new customers with the need to protect existing customers from inordinate costs.

EAL has addressed this concern with the roll-in formula in the contribution policy. EAL considered that it was not the intention of the contribution policy in general or the radial definition or roll-in formula in particular to ensure the roll-in of “a high proportion of expected new facilities costs” as suggested by AE and that would not be the effect of the roll-in.
EAL noted that there was no consensus from stakeholders on classifying new transmission costs as "system related". The traditional practice based on the number of customers served and type of customers served was unsatisfactory, unpredictable, and all too subjective. Given a particular magnitude and shape of electrical demand, neither the number of customers nor the nature of their activities are determinants of system cost, and are therefore not relevant to customer contribution determinations. To put it simply, for the same load it does not matter, in EAL’s view, whether there is one customer, ten customers or a thousand customers.

EAL submitted that Article 9 reduced uncertainty by classifying system and customer-related costs based on the type of transmission facility, not the type of customer. In accordance with Article 9.2, all radial costs are customer-related costs. "Radial" was not defined in the T&C. EAL did not believe such a definition is necessary, but would be prepared to insert one in the T&C if customers so desire.

EAL did not believe that it would be reasonable to include the cost of a transmission extension in its rates where there is a cheaper distribution alternative. Article 9.4 ensures that the TA’s existing customers will be protected from that eventuality.

EAL anticipated that it would work in co-operation with the DISCOs to determine whether transmission or distribution solutions were the cheaper alternative. The TA and the DISCOs already have a high degree of communication on this issue and others like it. If a distribution solution were the most cost effective and a customer continued to request a transmission solution, the Roll-in Ceiling would be set at zero and the customer would pay 100% of the transmission facilities cost.

The proposed contribution policy was not “symmetrical”. In other words, the contribution policy applies to demand customers but not to supply. IPPSA and TransAlta raised this issue in their cross-examination of EAL during which a number of possible inequities were discussed. EAL saw some merit in making the policy symmetrical.

EAL did not agree with TCE’s recommendation that the contribution policy account for differences in reliability. EAL noted there was no agreement on how reliability should be measured and compared, let alone on whether it should be a factor in the contribution policy.

Since the relationship between reliability and rate design, including contribution policy, will be the subject of upcoming stakeholder consultations on the TA’s rates as well as between the TA, the TFOs and stakeholders for TFO Performance-Based Rate (PBR) discussions. EAL considered discussion of the potential application to the contribution policy of unidentified reliability criteria to be premature and not suitable for consideration in this proceeding.

EAL concluded that its proposals did not violate the postage stamp provisions of Section 27(2)(b) of the EU Act. AE and the FIRM Customers took the position that EAL’s proposal would be contrary to the postage stamp requirement. EAL noted that both these intervenors agreed that a contribution is a necessary cap on the postage stamp philosophy. EAL’s contribution policy did not differentiate among DISCO systems based on geographic location.

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4 Exhibit 99, Written Evidence of William B. Marcus, pages 6 to 8 and Tr. p.3158, line 4 to 3159, line 18.
customer in Grande Prairie who is 10 miles from the transmission system pays the same contribution as a customer in Lethbridge who is 10 miles from the transmission system. All DISCO systems are treated the same regardless of their location.\textsuperscript{5}

EAL believed that it was consistent with the philosophy of Decision 2000-1 that a customer contribution “exerts some of the discipline of the utility’s economics on the economic decision-making of the customer.” EAL submitted that the DISCO is the customer of the TA. EAL’s contribution policy would exert some of the discipline of the TA’s economics on the economic decision-making of the DISCO.

EAL submitted that, in the absence of a contribution policy that charges DISCOs a contribution for multi-customer PODs, there is little discipline imposed upon the DISCO’s requests for transmission service. If a DISCO is not subject to a contribution for a multi-customer POD, there is little to prevent a request for service for an end-use customer that is “out in the woods somewhere”, other than the cost of isolated generation or distribution extensions.

EAL stated that certain potential refinements to the contribution policy would be acceptable to EAL. If the Board were to conclude that these refinements would be appropriate, EAL would revise the T&C accordingly. For example, TCE proposed that the Commitment Term Amount should not be based on a series of 5-year commitment term “pricing cliffs.” Rather, “interpolations” between the 5-year points should be used. EAL was prepared to provide interpolations between the 5-year commitment period points.

EAL was prepared to make reciprocal the adjusted customer contribution based on revised commitment terms and revised Revenue Related Amounts where a customer intends to increase his contract capacity.

Article 9.6 of the T&C required customers to pay interest at the rate of 12% per year for the number of years between the date of the original customer contribution and the revised customer contribution where a customer reduces its contract capacity before the completion of its commitment terms.

EAL was prepared to use a Board-approved weighted average cost of capital rather than the 12%, if the Board believed this to be appropriate. EAL noted that determining a weighted average cost of capital may be difficult where TFO rates are set by settlement and no weighted average cost of capital is explicitly expressed.

EAL was prepared to calculate the revenue-related portion of the Roll-in Ceiling based on the levelized annual revenue from a new service over all the commitment terms, as proposed by TCE as long as the future increases are contracted at the time of the original commitment.

Where the TA’s Transmission Development Plan shows a proposed radial extension will be looped within 5 years from the date that a customer signs a System Access Service Agreement for the radial line, no contribution will be required.

\textsuperscript{5} Tr. p. 1459.
EAL stated that it would be reasonable to amend the language in Article 9.2 to make explicit reference to the 5 year planning horizon. If a radial line is not planned to be looped within 5 years of a customer signing a System Access Service Agreement ("SAS Agreement") the customer would pay the contribution. The next annual update to the 5-year plan could show the radial line as being looped within five years of the customer signing an SAS Agreement. In that case, the customer would not be released of its obligations to pay the contribution. However, if the line were looped within the 5-year period, the customer would receive a refund of a portion of the contribution.

EAL believed this to be a reasonable balance between the need for certainty and the need to protect the customer’s interests.

EAL submitted that customers need to know what contribution policy will apply to their projects. There is a need for certainty now when many new customers are waiting to connect to the transmission system. This need for certainty, combined with the TA’s inability to offer customers the option of re-calculating customer contributions on the basis of the new policy if approval is delayed, has driven the need for separating the customer contribution policy issue into a separate module for an early decision.

EAL stated that it appreciated the Board’s willingness to consider this module on an expedited basis.

With respect to rebalancing of contributions, EAL noted that the payment of a contribution conferred no capacity rights beyond the expectation of service received by customers who paid no contribution at all.

EAL noted that the term “negative contribution” had also been referred to as the “Option B” approach. EAL understood both terms to define a situation where the Roll-in Ceiling for a customer exceeded the cost of the customer’s facilities and the customer receives a cash payment for the difference or some portion thereof.

EAL noted that only TCE supported such a concept. TCE implicitly assumed that customers would make location choices based on the TA’s contribution policy. EAL considered it extremely unlikely that any customer would respond to the TA’s contribution policy in making its siting decisions for industrial or commercial facilities, which are generally located to take advantage of particular resources or infrastructure. EAL did not support negative contributions and noted that other customers, particularly the FIRM Customers, were adamantly opposed to its adoption.

EAL noted that there was general agreement with its proposal to refund a portion of the original customer’s contribution, with some disagreement with details. Article 9.10 was intended to balance the need for administrative efficiency with fairness. Attempting to calculate a contribution refund 20, 30 or even 40 years into the future after the system has changed significantly and many customers have come and gone, is likely to be administratively burdensome and subject to fractious debate.
Rebalancing of contributions is not simply a clerical exercise, it is a problem of interpretation involving consideration of all system developments, changes in ownership, configuration changes (e.g. from net loads to net generators, and additional customers since the original customer made its contributions).

In reply, EAL noted that neither AE nor the FIRM Customers argued that the proposed contribution policy is contrary to the EU Act. Contrary to the suggestion of AE, there was no requirement that transmission rates be ‘averaged’ across the province. The EU Act contains no such requirement, nor do AE or the FIRM Customers argue that it does. Instead, AE argued that the contribution policy is “a significant change in government policy”.

EAL noted that the FIRM Customers may have their own conception of ‘government policy’, but it is not consistent with the “policy” as reflected in section 27(2)(b) of the EU Act. EAL submitted that no policy documents or other statements of government policy were produced by AE in support of this proposition.

EAL considered that AE and the FIRM Customers were inconsistent in their adherence to the postage stamp “principle”. Both intervenors agree with charging a contribution to a single customer behind a POD. Both intervenors are prepared to charge a contribution to more than one customer behind a POD. AE is apparently prepared to have a contribution charged to “a single customer or a few customers.”

EAL noted that the FIRM Customers considered it appropriate to charge many customers in the case of oilfield accounts signing contracts with less than a fifteen-year term. EAL concluded that it did not violate the postage stamp “concept” of the EU Act to place economic discipline on DISCO decisions. Therefore, EAL’s proposed contribution policy complied with the EU Act.

EAL considered that AE was overly concerned with the results that might occur, were EAL’s proposed contribution policy to be implemented. As a consequence, EAL considered that AE’s arguments consisted of logical syllogisms. EAL concluded that the differences between EAL and AE were the degree of discretion to be applied in determining the need for and amount of a contribution and whether the TA’s contribution policy should apply to DISCO PODs.

EAL disagreed with AE that EAL’s contribution policy was not consistent with the contribution policy of the DISCOs.

The contribution policies of the DISCOs were based on an overwhelming discretion in determining the system versus customer issue. This created wide variations in the application of the DISCO policies within the individual DISCO service area and between the service areas of different DISCOs.

EAL submitted that it should not be surprising that there are differences between EAL’s policy and those of the DISCOs.

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6 AE Evidence, p.11.
7 AE Argument, p.2.
The results of EAL’s and the DISCOs contribution policies are similar to those of applying the contribution policies of the DISCOs, particularly over time. EAL submitted that it was neither possible nor desirable to make the results identical.

EAL did look behind the POD on a routine basis for transmission planning and customer relations purposes. However, EAL submitted looking behind the POD was not necessary or even relevant to calculating a customer contribution policy. AE was wrong that EAL was inconsistent in this matter.

It appeared to EAL that AE differentiated between its view of the purpose of a contribution policy and that of EAL. AE's purpose was apparently to create the impression that the EAL policy would lead to the rolling-in of more facilities than the AE approach and that customers would suffer as a result. EAL submitted that AE’s intention was contrary to the evidence, particularly the evidence elicited by counsel for AE when cross-examining EAL.

EAL noted that ENMAX sought an amendment to the T&C to give the TA the authority to require additional security from customers, post-construction, to guard against the potential that the customer may go bankrupt or otherwise disappear before the end of its contract term and exit term.

EAL noted that the ENMAX recommendations for amendments to the T&C were not raised in direct evidence but through cross-examination and ENMAX's opening statement. EAL noted that the concept was simple, get more security, but the practical implementation was not so simple. Requiring additional security, such as letters of credit or performance bonds over long periods of time could have significant impacts on customers which have not been debated in the consultations to date.

EAL did not believe that the discussion on the record in this proceeding provided the Board with a sufficient record upon which to base a decision. EAL recommended that the ENMAX proposal be deferred until the next General Tariff Application (GTA) prior to which it could be discussed in the stakeholder consultations and more fully addressed in evidence.

ENMAX proposed a review of the contribution policy in two (2) years. EAL considered that, if problems arose in implementing the proposed contribution policy, it would be appropriate to put the matter before stakeholders once more in a consultative process and, if necessary, bring the matter back to the Board. EAL submitted that a fixed requirement to return to the Board in two years was neither necessary nor appropriate.

EAL noted the FIRM customer's approach that the contribution policy should not apply to DISCOs. EAL noted that there were three exceptions to the FIRM Customers' approach, two of which (connecting supply resources and connections more expensive than a distribution or isolated service alternative) would be caught by the TA’s policy in any event. The third exception dealt with the case of over 50% of the load on the interconnection being industrial or oilfield load that will not sign a contract in excess of 15 years. EAL opposed this third criterion for applying the contribution policy as unduly discriminatory.
With respect to the FIRM Customers proposal that allocation of a customer contribution should depend on the single-customer percentage of load at a new POD, EAL considered that it could result in one customer being charged a contribution for a facility used by many. EAL noted that the FIRM Customer’s approach, with its range of reasonableness, continued the existing uncertainty as to when a contribution would apply. EAL’s radial v. looped approach would avoid such a problem.

EAL believed that its approach to the Roll-in Ceiling was preferable to the proposal of the FIRM Customers. Mr. Marcus recommended escalating revenue multipliers based on contract commitment. The FIRM Customers themselves noted that this approach would not be appropriate where a contribution policy applies to a DISCO. EAL further submitted that there was no evidence on the record supporting the revenue multipliers and contract terms suggested by Mr. Marcus.

EAL’s Roll-in Ceiling proposal was the subject of extensive debate among stakeholders and appeared to enjoy substantial support. EAL submitted it should be approved rather than the approach suggested by the FIRM Customers.

EAL noted that the FIRM Customers recommend the use of the ratio of DTS/(DTS + STS) to determine the supply customer-related costs and the demand customer-related costs for transmission facilities prior to applying a contribution policy.

EAL considered this reasonable but this recommendation was not the subject of stakeholder consultation, nor was it the subject of direct evidence. EAL was concerned that the potential impacts on other customers have not been fully canvassed. EAL would be prepared to accept the refinement proposed by the FIRM Customers if there were no significant objection.

EAL noted that it had already agreed with TCE’s recommendations 2 to 4 in argument. EAL, in reply had the following comments on the remaining TCE recommendations.

Recommendation 1: EAL agreed that consistent criteria should be applied in all cases, whether or not the second line of supply is physically close to the first line of supply when it re-enters the transmission system. However, this did not imply that “a loop is any service with two or more lines of supply (legs) to a POD.” As long as the fundamental purpose of the extension was to serve a single customer radially, the wires do not constitute ‘system’ facilities. Adding a second line in parallel to serve a single customer would not constitute a “loop”. The facilities would still be radial in nature or a “double radial”. In order for a second line to constitute a “loop”, the lines must be separated by a substantial distance between the points where the lines join.

Recommendation 5: EAL stated that TCE’s recommendation 5 should be rejected. First, there was a risk in relying too heavily on load forecasts, as the AE Ring Creek example demonstrated. Secondly, the TCE proposal was an incentive to game the system based on the “lumpiness” of transmission investment. There was too much incentive for the customer to understate its long term load requirements and then rely on the “excess capacity” to meet its requirements.
Recommendation 6: EAL understood this recommendation to apply where construction of a facility contemplated by the 5-year Transmission Development Plan was accelerated at the request of a customer, e.g., where a facility was forecast to be required in year five and a customer requires service in year two. In that situation, TCE recommended that the customer only be charged the costs of accelerating the construction. Presumably, these costs would include the time value of money and any incremental administrative costs, but not the cost of design, materials acquisition or construction.

If EAL’s understanding was correct, the recommendation would be reasonable as long as it did not create uncertainty and time-consuming debate between the TA and the customer. If the TCE recommendation were implemented, EAL recommended that it be subject to the TA’s discretion to determine the applicable cost of accelerating the facilities.

Recommendation 7: EAL disagreed that the TA should use a five-year planning horizon on a rolling basis. The five-year period was to run from a fixed date. The customer paying the initial contribution was protected by the refund policy.

Recommendation 8: Under EAL’s proposal, the cost of transmission should not exceed the cost of isolated generation or a distribution option. EAL did not consider it appropriate to attempt to quantify “system benefits” that arose from construction of a radial line at a particular point on the transmission system. TCE did not suggest any methodology to accurately determine these benefits and assign a value to them. Even if a methodology were developed, it would be a matter of opinion and subject to extensive debate between the TA and its customers. Finally, calculation of “system benefits” is likely to be subject to considerable debate and require the exercise of considerable discretion on the part of the TA. EAL submitted that this recommendation re-injected into the process the very uncertainty and lack of transparency that EAL believed TCE was attempting to avoid when it supported EAL’s general approach to the contribution policy. EAL believed this recommendation was unworkable and unnecessary.

Recommendation 9: EAL dealt with the “standard reliability levels” issue in argument.

Recommendation 10: EAL considered that a Board direction to the TA to determine “substandard, standard and above standard reliability level” for purposes of the next GTA was unnecessary. EAL agreed that a determination of baseline standards for reliability would be necessary for a PBR process, particularly for the TFOs. EAL considered that it was unlikely that TCE’s recommendation could be concluded before the next GTA. TCE itself concluded that such a process could take up to two years. EAL submitted that the TCE recommendation was unrealistic.

Recommendation 11: EAL strongly opposed including, as “system”, a cost that would be required to improve the reliability to a single customer. This was contrary to both the philosophy and the mechanics of the proposed contribution policy, which TCE appears to support.

Recommendation 12: EAL agreed that any certainty the Board can provide with respect to its views on the interpretation of the “postage stamp” requirement in section 27(2)(b) of the EU Act

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8 Tr.p.3273.
would be helpful. EAL considered that the Board was clear in its position at page 270 of
Decision 2000-1, where it concluded that contribution policies are necessary and not a
contravention of the postage stamp provisions of the EU Act.

Recommendation 13: EAL considered that this proposal was rejected by the Board in the last
GTA. There was no reason for the Board to change its earlier decision.

Recommendation 14: TCE’s modified “Option B” should be rejected for the reasons already set
out in EAL’s Argument.

Recommendation 15: EAL indicated in argument that it did not oppose TCE’s recommendation
15, bullet 2. EAL also indicated partial acceptance of the point set out in TCE’s bullet 1.
However, EAL did not necessarily consider the recommendations in these bullets were
appropriate. Recognizing the staged development of a customer load for purposes of the
contribution policy was appropriate but only where the customer has signed a long-term contract
that includes those increases. For example, if a customer signs a twenty year contract with
forecast load increases every five years, that is a factor that could be taken into account (subject
to verification) when calculating the customer contribution. However, the customer must agree to
be contractually bound to the staged increases upon which the customer wishes the contribution
to be based. EAL agreed with the Cities that recommendations such as contained in bullet 3 were
too detailed and represented seriously diminishing returns.

With respect to rebalancing of contributions EAL believed that the 10-year limitation in Article
9.10 was reasonable in the circumstances and will be difficult enough to implement as it is.
Therefore, EAL did not support TCE’s recommendation that the contribution refund be available
over the useful life of the facilities. TCE attempted to recognize the potential administrative
difficulties with its proposal by suggesting a cap of $50,000 below which the “lifetime refund”
approach would not apply. If a cap approach were to be used, which EAL did not recommend,
then it should be at least $2 Million. If the TA is required to go to such extremes, it should only
be for substantial amounts.

2.2 Views of AE

AE commented upon EAL’s definition of customer versus system costs, the proposed formula
for determining customer contributions and the proposed formula to be used for rebalancing a
contribution when a new customer subsequently uses facilities for which another customer has
made a contribution.

AE acknowledged that EAL’s approach to the determination of contributions was relatively
simple and avoided the need for subjective analysis.

AE maintained however that the ‘customer versus system’ problem was, in fact, complex and did
not have a simple, formula based solution that produced reasonable and fair results on a
consistent basis. It was therefore AE’s position that, at a minimum, some form of ‘principle
based’ assessment must be used in combination with a formula based approach, if not to replace
it altogether. AE claimed that a principle based method was consistent with previous Board
decisions that clearly indicated that a case by case assessment was appropriate with respect to the ‘customer versus system’ issue.

AE further proposed that, if a subjective, principle based assessment was deemed appropriate, then the involvement of the affected DISCO was imperative and wholly appropriate. The DISCO was the counter party to both the TA and the end-use customers and therefore this was not a matter that could be determined at the sole discretion of the TA.

AE stated that EAL’s definition of radial extensions as customer costs was not appropriate for transmission extensions which served as bulk delivery systems, serving many diverse end-use customers. Simply because an extension was radial, did not mean it was not a ‘system’ facility. In other words, it was important to distinguish between a wholesale customer (i.e. a DISCO) and an end-use customer when determining the portion of the costs of new facilities that should be rolled in to average rates.

Failing to make this distinction may ultimately cause system costs to become no longer averaged (i.e. not ‘postage stamp’ across the province). It was AE’s firm belief that this result was not the intent of the EU Act.

AE stated that it understood the contribution formula contained in Article 9.3 was to have the effect of rolling in a high proportion of expected new facilities costs, and was intended to balance the rather stringent definition of ‘customer’ resulting from the application of Article 9.2. However, AE did not believe the combination of the two necessarily produced valid results.

AE maintained this was supported by the data, supplied at Attachment 1 of its evidence, relating to several actual transmission projects required by AE to serve its customers in the recent past.

AE also maintained that any signal that could presumably be provided via contributions resulting from the TA classifying costs as ‘customer’, which in fact related to many end-use customers, would be lost in the translation to distribution end-use rates, when applied to multiple distribution connected loads. With a diverse group of end-use customers, whose loads change over time, it was not possible for a DISCO to directly assign a meaningful portion of any TA imposed ‘customer’ related contributions to its end-use customers.

AE stated that any contributions made to the TA by AE, related to transmission facilities serving many customers, would be rolled into its transmission rates (of the Distribution Tariff), thereby raising the average rates to only AE’s customers.

AE further stated that it did not believe the customer versus system determination, should it be done subjectively, could be at the sole discretion of the TA, as it was the DISCO that had visibility and knowledge of its customers’ requirements and future plans. It was for this precise reason that the industry is structured such that the DISCO (and not a retailer or end use customer) is the counter party to the TA. As such, customers contract with and pay AE (not the TA), while AE (not the customer) contracted with and paid the TA.
AE proposed that the customer versus system determination should be a function of whether the transmission facilities in question would serve the purpose of delivering ‘wholesale’ electricity, and this should be based on information provided in part or whole, by AE (or the affected DISCO). AE also stated that this assessment must be tempered with professional judgement as no simple deterministic formula could be used.

AE would define ‘wholesale’ as service to multiple end-use customers, and the cost of any facilities required for that purpose would be classified as ‘system’ costs. On the other hand, transmission extension costs driven by the need of an identifiable end-use customer or customers should be classified as ‘customer’ and those costs should be offset by the applicable ‘roll-in’ amount. AE also maintained that this was consistent with the position AE put forward during EAL’s 1999/2000 Phase II proceeding, and agreed with historical practice employed by AE as an integrated utility, and continued to average system costs in an appropriate manner.

AE also stated that the cost sharing scheme proposed by EAL in Article 9.10 was appropriate. However, AE added that cost sharing should also take the form of refunding an amount related to facilities that were originally deemed ‘customer’, that have been determined to have evolved into ‘system’. In this case, the costs associated with the ‘system’ related facilities would be moved into rate base, and refunded to the customer of the TA who made the original contribution.

In argument, AE opposed the proposed customer contribution policy because it was inconsistent with the purpose of a contribution policy. AE argued that it did not achieve the objective of protecting the utility and its customers from the risk that such customers will have to pay, through general rates, for a facility built for the benefit of only a single or a few customers.

AE noted that the Board had directed EAL to make its contribution policies consistent with those of the DISCOs. It was AE’s position that Attachment 1 of AE’s evidence amply demonstrated that EAL’s proposal and AE’s policies resulted in vastly different results. What EAL sought to do was the reverse of the Board’s direction. EAL created a contribution policy and forced the DISCO to be consistent with the TA’s policies.

AE considered that EAL’s proposal was arbitrary, as costs are attributed to system or customer simply on the basis of whether the POD is connected by a looped or radial line, without regard to the purpose of a customer contribution, or various other considerations relevant to the system versus customer determination. The choice of a radial or looped extension is often an engineering decision, based on the happenstance of timing and geography⁹.

AE submitted that the criteria in Attachment 2 of its evidence addressed directly the objective of a customer contribution and were considerably more relevant and less arbitrary than the system versus customer distinction proposed by EAL. AE stated that the cases in Attachment 1 were neither ingenious nor contrived, but rather applied EAL’s proposal to actual circumstances. AE stated that the additional example of Jasper illustrated the arbitrariness of EAL’s proposal. AE’s criteria for determining the customer versus system were not arbitrary and were a fairer method of determining contribution levels.

⁹ Tr. p.3069
AE submitted that the arbitrary basis of EAL's proposed contribution policy undermined the effectiveness of contributions as price signals for customers. Fairness led to effective price signals and, if a customer contribution is intended to provide a price signal, the decision of whether to assess a contribution should not rest on the looped versus radial distinction.

AE considered that its criteria for assessing a contribution are less arbitrary and more relevant than the looped versus radial distinction. Therefore, they would provide a fairer and more effective price signal. Moreover, AE noted that a price signal is of limited use for siting purposes in circumstances such as resource development, since operations must locate in proximity to the resource being exploited.

The price signal for resource development projects would not affect the location but would affect whether the project proceeded.

The effectiveness of a customer contribution as a price signal to customers who cannot relocate, such as towns or resource developers, lies not in where to site the facility, but rather whether to proceed with the facility at all (i.e. the appropriate costs must be paid by the party(ies)). AE submitted that EAL's policy left no room for such practical considerations.

AE noted that whether an extension is radial or looped is subject to considerable uncertainty. In addition to AE, parties such as TCE and ENMAX expressed concerns, in cross-examination of the Applicant, respecting the vagaries of classifying facilities as looped or radial\textsuperscript{10}.

AE also was concerned that the 5-year planning horizon forecast component of EAL's proposed customer contribution policy created uncertainty and could become the subject of disputes between parties. AE submitted that a forecast is only one of the factors that need to be considered in assessing a contribution. EAL's proposed policy relied heavily on a 5 year forecast, but the Ring Creek example, as raised by counsel to EAL in cross-examination\textsuperscript{11} of AE, showed the problem of relying on a forecast alone.

AE submitted that EAL's proposal was unfair to end-use customers, as the proposed policy does not take into account relevant considerations which exist "behind the POD," for instance in circumstances where numerous end-use customers are served from a single POD connected by a radial line.

In order to treat end-use customers fairly, a customer contribution policy must allow for the application of discretion (based on relevant, enumerated criteria) having regard the circumstances "behind" the POD. It is necessary to exercise discretion and consider the reality behind the POD in order to achieve fairness, and in order to treat like parties alike. AE indicated in evidence that it is somewhat simplistic of EAL to suggest that it need only consider its customers, without having regard to what is behind the POD\textsuperscript{12}. AE considered that EAL did look beyond the POD and did consider the "end-use" customer when it suited EAL's convenience.

\textsuperscript{10} Tr. p.1156, p.1485, p.1587 and p.3693
\textsuperscript{11} Tr. p.3153-4
\textsuperscript{12} Tr. p.3189-90
AE submitted that, in assessing the EAL’s contribution policy, it is critical to look beyond the POD to ensure that customers are treated fairly.

AE noted that parties supporting EAL, such as TCE, acknowledged that flexibility is necessary to preserve fairness, and that there are a number of factors beyond the looped versus radial distinction which need to be taken into account in determining whether a customer contribution is payable. A similar acknowledgment respecting the need to look beyond the POD was made by IPCC.A. TCE’s evidence included 15 different modifications to EAL’s proposal, which merely demonstrated the complexities in TCE’s recommendations. AE submitted that TCE was not attempting to remove discretion but to substitute a different manner of discretion suitable to TCE’s purposes.

AE submitted that EAL’s proposed policy did not bring nearly the degree of simplicity in calculating customer contributions as EAL would suggest. AE submitted that much more discretion had to be exercised than EAL acknowledged so that AE’s proposal is not unlike EAL’s, in that each requires the exercise of discretion. The only difference was that AE acknowledged this discretion and enumerated the considerations, whereas EAL continued to vacillate over whether discretion should be applied through a consideration of circumstances beyond the POD.

Finally, AE considered that EAL’s proposal was contrary to the postage stamp transmission rate principle, since where a customer contribution is required by EAL in circumstances where the DISCO would attribute those costs to system, those costs can only be distributed through the DISCO’s service area, thereby unaveraging transmission rates throughout the Province. While this may not have been EAL’s intent, it will certainly be the result.

Such a significant change in government policy should not arise indirectly through amendments to EAL’s contribution policy but should be a matter for government policy makers. AE noted that Mr. Marcus on behalf of the FIRM Customers also expressed this concern at Tr. pp. 3530-3531.

AE noted that EAL admitted that it had not considered the manner in which its proposed policy will undermine the principle of postage stamp transmission rates. EAL’s “overly-simplistic” view ignored the very real adverse effect on AE compared to other DISCOs. This was because EAL can disperse a system cost across the province but the DISCO can only disperse a system cost through its service area. System costs are presently dispersed through the entire province. AE submitted that, if EAL’s proposal is adopted, the system costs of radial lines serving PODs with multiple end-users will be distributed only through the DISCO service area. AE submitted that this result would unaverage transmission rates and, as a result, undermine the postage stamp principle.

AE submitted that its DISCO customers would be adversely affected by EAL’s proposal but the other DISCOs may benefit from EAL’s policy through lower transmission rates in their service.

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13 Tr. p.2767
14 Tr. p.2959
15 Tr. p.1459

18 • EUB Decision 2001-6 (February 2, 2001)
areas. AE noted especially the ambiguous position of ENMAX in testimony at the hearing. AE noted that Mr. Marcus readily agreed that EAL’s proposed customer contribution policy would lead to higher transmission rates in predominantly rural service areas. Mr. Marcus also testified that care should be taken prior to adopting the applied-for customer contribution policy, as the indirect effect of EAL’s proposal would be the unaveraging of transmission rates, potentially leading to considerably more expensive transmission rates in AE’s service area. Finally, TCE acknowledged that customers could receive variable treatment under EAL’s proposal.

AE requested that the Board not approve the customer contribution policy proposed by EAL and issue a direction that EAL adopt a contribution policy similar to AE’s proposal and has regard to the factors indicated in Attachment 2 of AE’s evidence. AE noted that, from EAL’s testimony, it appeared that EAL was prepared to apply judgment in the application of a customer contribution policy.

In reply, AE noted that ENMAX and IPCCAA had expressed concern with EAL’s proposal but suggested that interim approval be given and the matter revisited shortly. EAL had requested early approval of its proposal. AE disagreed and urged the Board to take all the time necessary consider all the evidence before it on this matter. AE disputed EAL’s statement that the nine criteria proposed by AE had no certainty attached to each one. AE submitted that the Board need merely examine Attachment 2 to see how its proposal removed uncertainty. AE rejected the Cities’ criticisms for not putting its past contribution policy in writing and reducing uncertainty. AE submitted that its proposal, by placing its policy in writing now, would increase the predictability and consistent application of contribution policies.

AE rejected EAL’s argument that there was no role for the DISCO in classifying facilities as system or customer as AE provided the TA with information behind the POD. AE submitted that providing information “beyond the POD” was irrelevant if EAL will not use that information. EAL variously says it will not look behind the POD, even though the evidence demonstrates that EAL does look behind the POD. The contradiction underlying EAL’s position underscored the need to specify criteria beyond the looped versus radial distinction and for EAL to involve the professional judgment of the DISCO in the system versus customer determination. EAL states it is willing to work in cooperation with DISCOs to determine whether transmission or distribution solutions are the cheaper alternative, which beg the question why cooperation on classifying facilities as system or customer is not desirable.

AE agreed that the distinction between a single end user and a large group of end users may be irrelevant for the purposes of determining what will be built but the distinction was entirely relevant in the context of assessing the risk that stranded costs could be imposed on others and ensuring that parties which attract greater than average costs pay for them. If the question were

16 Tr. p.3690-2
17 Tr. p.3531
18 Tr. p.3569-70
19 TCE Argument, p.12
20 EAL argument, p.3
21 EAL argument p.8
irrelevant to the TA then there would be no rationale for any customer contribution at the transmission level, and it would be most efficient that all extensions be treated as system.

AE submitted that the Cities ignored the underlying rationale for a customer contribution policy, as a means of addressing the risk of stranded costs and of ensuring that those who attract greater than average costs pay for them when the Cities suggested “There does not appear to be any reason in principle (except historical precedent arising from the operation of integrated utilities) why there should be a distinction between a single and a multiple customer-based investment” AE submitted the risk of stranded cost can increase with only a single end-use customer, as opposed to multiple end-use customers.

AE noted that TCE’s characterization of looking behind the POD as “artifice” contradicted TCE’s proposal that EAL take into account reliability as a factor in classifying facilities as system or customer. Mr. Leveson acknowledged that a reliability standard would require looking behind the POD22. AE noted that TCE asserted23 that AE was confused as to which parties are actually EAL’s customers. This was contradictory because AE demonstrated that, when EAL and others referred in evidence to “customer,” they were actually referring to end-use customers behind the POD, notwithstanding those same parties supported the proposed policy which purports not to have regard to considerations behind the POD. AE stated that it was fully aware that EAL’s customers are DISCOs. However, considerations about end-use customers afforded a more solid basis to determine whether facilities are system or customer than simply whether those facilities involve a radial or looped extension.

AE noted that no other party in argument except the FIRM Customers group acknowledged that EAL’s proposal would unaverage transmission rates. AE, however, considered the limited measures proposed by FIRM Customers to address that unaveraging appeared to discriminate against resource developers and other industrial customers in favor of other residential and commercial loads.

AE submitted that TCE was incorrect when it suggested that AE’s position was that all customer contributions contravened section 27(2)(b) of the EU Act.24 AE nowhere suggested that a customer contribution is contrary to the Act, but it remains unchallenged that under EAL’s proposed policy certain system costs would no longer be dispersed throughout the province but would be dispersed only through a distribution service area. AE submitted that, irrespective of compliance with section 27(2)(b), this would be a significant change in the allocation of system costs that would unaverage transmission rates and undermine the postage stamp principle.

AE reiterated that adherence to a postage stamp principle is a matter of Department of Resource Development policy and should not be decided by default, as an indirect effect of the Application.

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22 Tr. p.2772-3  
23 TCE Argument p.17  
24 TCE Argument p.14-15
2.3 Views of the Cities

The Cities supported the use of the proposed roll-in formula. The Cities considered the proposal was objective, open and predictable. The Cities noted that there were some complaints about the administration of the formula over time. In particular, TCE suggested some changes to the provisions of the Article 9 dealing with the administration of the policy. The Cities did not oppose fine-tuning the operation of the provision to avoid unfair or inequitable results, to the extent that these changes would not create administrative burdens. Where such changes would create additional burdens, the Cities submitted that the Board should use care in adopting such modifications. This is particularly so with respect to the rebalancing provisions, which contemplate a 10-year cutoff. The Cities submitted that to extend that 10-year period further would create administrative burdens and may be of little relevance in a rapidly changing electrical world.

The Cities supported the TA’s position that there should be no negative contributions. The Cities’ submitted that the intent of almost all contribution policies is that the investment be an “allowance” or “ceiling” for extension costs, not a symmetrical “collar” in which all investments are equal, thus raising all tariff costs. The Cities also noted that this was the position of the FIRM Customers.

The Cities supported the TA’s initiative to introduce a policy that the Cities considered to be fair, open and non-discriminatory and which can be applied objectively. The Cities considered that pre-existing policies were not consistent and were subject to disputes as to their application and intent. For example, the evidence of AE stated that it had never reduced the elements of its policy to writing in a fashion that allowed predictability of the policy’s operation and administration. It was only in preparing evidence for this proceeding that AE identified the key components of its “principled” approach to customer contributions25. The nine considerations listed in AE’s evidence were not incompatible with the TA’s policy but injected additional discretion into the process.

The Cities noted that AE concluded that the objective aspects of the TA’s policy created inequities and unintended results. The Cities did not disagree that an objective general policy cannot in every case achieve perfect results. However, the appropriate response is not then to substitute a case by case discretionary determination of customer contributions. In the Cities’ submission such a proposal was fraught with problems of predictability, certainty, and consistency of treatment.

The Cities submitted that, even if the Board is satisfied that certain circumstances raised by one or more of the intervenors created an inappropriate result if the TA’s policy were applied, it was still preferable to adopt an objective policy which generally met the goals of predictability, certainty and consistency. The Cities considered that “outliers” could be exempted, with a strong burden lying upon the applicant for such exemption to demonstrate that the application of the policy would result in an aberrant circumstance. The Cities did not consider that the results of the case studies put forward by AE were unfair or unreasonable.

25 Attachment 2 to AE’s evidence
The Cities noted that there were certain aspects of the system versus customer split based on looped versus radial distinctions that arose during the hearing that were not entirely clear. For example, dual radial improvements remain radial and thus "customer" improvements, and not looped or "system" improvements. Most of those uncertainties appear to have been sorted out to the point that parties understand but perhaps do not agree with the results of the policy.

The Cities noted that it appears that, notwithstanding the uncertainties arising from the TA’s classification system, the results are more certain than the previous contribution policy with respect to whether an improvement was system or customer. The Cities submit that this would be an exercise of serious diminishing returns to attempt to fine tune EAL’s proposed policy as approximately 80% of projects will require no contribution.

The Cities submitted that the TA’s proposal should be approved. However, to assist in the application of the policy, various case studies such as those put before the Board could be compiled for the information of customers affected by the policy.

The Cities noted that both AE and the FIRM Customers argued that it is inappropriate to charge customer contributions with respect to transmission investment for DISCOs’ multi-customer load growth improvements. Both AE and the FIRM Customers submitted that to apply a customer contribution to a DISCO with respect to investment required for multiple customers of a POD infringes the “postage stamp” pricing policy dictated by the EU Act.

The Cities agreed that the operation of a customer contribution system could indirectly affect the level of overall rates paid by that customer as compared to other customers. This is true however, of any customer contribution policy. If multi-customer investment is not included, the single customer still faces an increased level of overall rate, which would also be contrary to the provisions of the Act, given that most of those customers remain DISCO customers. There does not appear to be any reason in principle why there should be a distinction between a single and a multiple customer-based investment. In order to ensure the operation of an objective policy, which is consistent with cost causation and avoids discriminatory treatment against a group of customers, the Cities submitted that the TA should be impartial as to the number and identification of the customers served.

The Cities noted TCE identified another issue that may have some future significance, which is that differences in level of reliability should result in differences in rates paid by the customers. The Cities agreed that there may be different levels of reliability and that, over time, customers may be prepared to pay for different levels. The Cities considered that there was insufficient detailed information to establish the levels of reliability experienced by customers currently. For example, a higher level of theoretical reliability may not translate into a higher level of actual reliability. The Cities agreed that it was appropriate to study actual reliability and assess the relationship with rates. Reliability was clearly relevant to the development of performance based rates and might assist in the further evolution of cost of service analysis for the development of fair and reasonable tariffs for transmission service.

The Cities supported the TA’s customer contribution policy. The Cities did not consider it perfect, nor would it perfectly deal with every case that might be brought forward in a fashion
that would be acceptable to all participants. The Cities concluded that EAL’s proposal represented a reasonable compromise with respect to a difficult issue and would provide an additional incentive to customers to make appropriate economic choices.

2.4 Views of ENMAX

ENMAX submitted that the purpose of a Customer Contribution Policy should be to ensure that a new customer has access to the electric system on a fair, equitable and non-discriminatory basis, while at the same time, protecting the interests of existing customers.

The factors to consider included:

1) the cost of providing service to customers on the system;
2) the nature of the services provided;
3) the cost of providing service to new customers;
4) the nature of services requested; and
5) the risk associated with serving new customers. ENMAX stated that it was concerned about the risk associated with serving new customers.

Whenever a new customer connects to the system, there was a risk associated with serving that customer. This included the risk of stranded costs in the event the new customer prematurely left the system. The proposed tariff included notice provisions relating to a reduction in contract capacity but there were instances where a new customer might leave the system, and where EAL would be unable to enforce the exit provision (such as insolvency or bankruptcy of a new customer).

ENMAX submitted that the proposed policy of the TA did not adequately address the risk associated with serving new load customers.

During the hearing, EAL proposed to mitigate the risk by exercising considerable discretion in determining the Roll-in Ceiling. ENMAX noted that there was no provision in the Customer Contribution Policy that provided the TA with this discretion to limit the contractual term.

Even if the TA were able to exercise some level of discretion and limit a contractual term, ENMAX submitted it would not be enough to mitigate the amount of risk to which the TA is exposed and would ultimately seek to pass on to its customers.

ENMAX noted that during the time of construction of facilities to serve a new demand customer, the TA does have considerable discretion over what forms of security it may seek from the customer under Article 8 of the Terms and Conditions of the Tariff. However, once construction is complete, and the facilities are put into service, the security that the TA had is no longer available. This loss of security places the TA and remaining customers at risk for what may be many millions of dollars.

To mitigate this risk, ENMAX proposed that Article 10 be amended as follows:

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26 Transcript Volume 8, 1157, lines 1-8.
1. Article 10 should be amended to provide the TA with discretion over what forms of security it will accept to mitigate the risk that a customer might abandon service and create the potential for stranded costs; and
2. Article 10 should be amended to provide the same level of security that the TA might require during the construction of new facilities, as contemplated and provided for under Article 8 of the Terms and Conditions of the Tariff.

ENMAX requested the Board to direct EAL to submit the customer contribution policy to the Board for review within two years of its implementation, in order to determine whether the policy is functioning as expected and is achieving the proper goals.

2.5 Views of the FIRM Customers

The FIRM Customers believed that the TA’s customer contribution policy for demand customers should be similar to the existing DISCO policy. That DISCO policy required individual customers in most classes to make contributions to the extent that their interconnection facilities were more expensive than the average. New DISCO customers must pay contributions to the DISCO if their interconnection costs are high. New individual customers who interconnect directly to transmission should pay contributions to the TA if their costs are high.

The FIRM Customers maintained that DISCOs, however, should generally not pay contributions to connect, expand, or upgrade facilities for interconnections serving many customers. Charging DISCOs a transmission contribution would have the effect of eliminating postage stamp rates for transmission in Alberta, since those DISCOs with more expensive interconnections (e.g., longer tap lines from the bulk transmission system) would pay more money for transmission than others. There may be a few exceptional cases where DISCO contributions would be required.

The FIRM Customers supported the five following aspects of EAL’s proposed contribution policy:

1. The TA’s proposal that generators pay the full cost of interconnection is appropriate, as decided in the 1999-2000 GTA.

2. The clearer distinction between customer and system loads proposed by the TA is appropriate.

3. The FIRM Customers supported the TA’s proposals to encourage customers (including DISCOs) to use cheaper options for service than transmission interconnection (distribution interconnection or isolated self-generation).

4. The FIRM Customers agreed with the TA’s proposal for contribution rebalancing.

5. The FIRM Customers strongly agreed with the TA’s proposal not to allow “negative” contributions (or “unused investment credits” in TransAlta’s parlance).
The FIRM Customers offered a definition that could be used to determine whether an interconnection was a DISCO demand interconnection (where contribution rules would not apply) versus a demand interconnection predominantly built to serve a single customer (where contribution rules would apply).

The FIRM Customers proposed that interconnections built predominantly to serve a single customer should be defined as those where over 80% of the load on the interconnection came from one customer. These interconnections would be treated as single-customer interconnections, and would be subject to contribution rules. The single large customer may receive proportionate payments of contributions from others served over the interconnection.

The FIRM Customers acknowledged that there were conditions where DISCO demand interconnections should pay contributions but these were quite limited. A DISCO or DISCO customer should be required to make a contribution for an interconnection or upgrade only where the following exceptional conditions applied:

- to the extent required to interconnect supply resources also associated with the same POD,

- to the extent that the interconnection was more expensive than a feasible distribution interconnection or isolated service, or

- over 50% of the load on the interconnection was industrial or oilfield load that would not sign a contract in excess of 15 years, in which case the load not signing a long-term contract should be treated under contribution rules in the same way as a single-customer interconnection.

The FIRM Customers agreed with the concept of a Roll-in Ceiling but believed that the Ceiling should be more tied to the revenue available to pay for the interconnection, rather than including a flat allowance of $2 million per five years of commitment regardless of the revenue derived from the interconnection, plus three years of revenue. The FIRM Customers recommended that the Roll-in Ceiling be based solely on projected revenue (excluding those system support service costs paid by loads), as follows:

- Zero for less than five years

- 2 times current revenue for a five to ten year commitment

- 3 times current revenue for a ten to fifteen year commitment

- 4 times current revenue for a fifteen to twenty year commitment

- 5 times current revenue for a commitment longer than twenty years.

The FIRM Customers explained that these revenue multipliers were to cover carrying costs of the new investment, O&M expenses, and ultimate replacement (in the long-term case), while reflecting that a portion of the transmission revenue was required for purposes other than the customer connection (e.g., bulk system O&M and new capital).
The FIRM Customers noted that EAL's proposed Customer Contribution Policy formula presupposed that radial facilities were either supply customer-related or demand customer-related.

If the radial facilities were dual-use, the facilities must be apportioned between supply customer-related and demand customer-related before application of the Customer Contribution Policy formula to determine the customer contribution amount. Supply customer-related costs should remain the 100% responsibility of the supply customer in accordance with Decision 2000-1 and such supply customer should pay 100% of these costs as a customer contribution. Demand customer-related costs should be subject to the Customer Contribution Policy formula to determine the customer contribution amount with the balance of costs rolled-in to the tariff as a system cost.

The FIRM Customers submitted this ratio approach could be utilized for each leg of an expansion where each transmission line and substation pair can be apportioned between supply and demand service to assign cost responsibility.

The FIRM Customers submitted that the policy of extending the benefits of transmission widely across Alberta through postage stamp rates was sound.

Transmission rates to rural utilities should not be raised relative to urban ones, since a contribution policy is based on averages. The FIRM Customers recommended that the TA's contribution policy for demand customers should mirror the DISCO's policy, which provides for constant rates for each customer class based on average cost regardless of location as the general rule, but required individual customers to pay excess costs of expensive interconnections\(^{27}\).

The FIRM Customers submitted that a policy requiring DISCOs to pay contributions for system facilities would have the clear long-term effect of raising rates in rural parts of the province, particularly for AE DISCO. At the same time, rates would be lowered for DISCO customers of municipal utilities and to a lesser extent, UNC DISCO customers.

The FIRM Customers submitted that, if the Board approved EAL's proposal, the Board should note in its decision that it is moving away from postage stamp rates, toward higher rates for rural utilities.

The FIRM Customers, through Mr. Marcus, proposed that interconnections built predominantly to serve a single customer should be defined as those where over 80% of the load on the interconnection comes from one customer. These interconnections would be treated as single-customer interconnections and would be subject to contribution rules. The single large customer would pay a contribution based on the application of contribution rules to its portion of the cost of the whole interconnection.

\(^{27}\) EAL-FIRM-1
The FIRM Customers recognized that there were a limited number of exceptional circumstances where a DISCO that served a number of customers should be required to make a contribution for an interconnection or upgrade.

One was where it is required to interconnect supply resources also associated with the same POD. This exception simply maintains the requirement that a supply resource pay for its interconnection, as currently required.

A second was when the interconnection is more expensive than a feasible distribution interconnection or isolated service. This exception was a critical means of maintaining cost discipline on the DISCO while still maintaining a postage stamp regime as the general rule for transmission. Such cost discipline was previously maintained through a regulatory process.

It is reasonable for the TA, in exceptional cases, to require a contribution where the specific interconnection is not economic when compared to other choices. These choices include interconnecting elsewhere to the transmission system, tying in the new load from the existing distribution system, or using isolated generation and not tying in at all.

The FIRM Customers proposed a third exception to recognize that short-term resource-based loads impose a greater risk on ratepayers of either the TA or the DISCO. While representatives of oil and gas interests suggested that it would be discriminatory to charge contributions only to industrial and oilfield loads, Mr. Marcus provided an explanation in response to information requests\(^{28}\) that resource-based loads have considerably more uncertainty than standard residential or commercial loads. It is also uncommon that residential or commercial loads sign contracts, as the load is likely to continue at the premises although the specific customer occupying the premises is likely to change over time.

The FIRM Customers supported EAL’s proposals to encourage customers (including DISCOs) to use cheaper options for service than transmission interconnection (distribution interconnection or isolated self-generation). The FIRM Customers considered this to be an exceptional case provision that would not routinely result in contributions by DISCOs or customers but would assure that only economic extensions are charged to ratepayers.

The FIRM Customers agreed with the concept of a Roll-in Ceiling but believed that the Ceiling should be more explicitly tied to the revenue available to pay for the interconnection. EAL proposed a flat allowance of $2 million per five years of commitment regardless of the revenue derived from the interconnection, plus three years of revenue. The FIRM Customers considered that EAL’s proposal could encourage inefficient connection, whereas the revenue-based FIRM Customers’ proposal would not.

The FIRM Customers noted that, should the Board decide that contributions are potentially required for all DISCO interconnections, a policy more closely aligned to that of the TA (with a base exemption of several million dollars) may be warranted to keep system costs closer to a “postage stamp” basis.

\(^{28}\) IPPSA-FIRM-4; TCE-FIRM-8
The FIRM Customers supported EAL's proposal (Article 9.6) for contribution rebalancing when a Customer reduces its Contract Capacity before the completion of its commitment terms.

The FIRM Customers strongly supported the TA position not to allow “negative contributions” or “unused investment credits”. The FIRM Customers submitted it was inappropriate to allow “negative contributions” for several reasons. First, the TA rates would be higher to pay for negative contributions that benefit only a few customers. Second, the FIRM Customers proposed that the TA’s contribution policy mirror the DISCO contribution policy with an objective of charging for interconnections that are more expensive than average and are not supported by revenue, while giving customers the benefit of interconnections that are cheaper than average. No DISCO customer class, except TransAlta industrials (for a few years), has ever received cash or rate discounts if their costs were lower than the allowance before contributions were required. There was no reason why the TA’s direct-connect customers should be treated preferentially to the vast majority of DISCO customers by being granted such a subsidy.

The FIRM Customers were concerned that Article 9.10 of the Customer Contribution Policy did not clearly address or consider that adjustment of customer contributions should be dependent on whether the new interconnecting customer is a supply customer or a demand customer. The FIRM Customers submitted that EAL should utilize the ratio approach discussed in Section 3.0 of the FIRM Customers’ argument.

2.6 Views of Fording Coal (Fording)

Fording stated that, in evaluating the feasibility of coal-fired generation in southern Alberta, it has been unable, to date, to determine its liability regarding the cost of interconnecting to the Alberta Interconnected Electric System (AIES). Fording maintained that this uncertainty regarding Fording’s responsibility for deep system costs has effectively put a barrier towards progress in developing generation in southern Alberta.

Based on the existing Terms and Conditions, Fording understood that there were no capital credits nor provisions for sharing of system-related costs and that Fording would be responsible for the entire cost of upgrading the existing system. Fording noted it would be responsible for these costs regardless of any benefits other customers may experience through the upgrade to the existing 240 kV non-radial systems (benefits include additional voltage support in southern Alberta, a reduction in line losses in Alberta, etc.). Fording submitted it was unfair to require new generation to pay for the cost of upgrading the deep system when other generators have not been responsible for the cost of upgrading the deep system.

Fording claimed that EAL had corrected this situation in their Application. First of all, the TA has proposed to consider system-related costs and customer related costs separately. The TA has proposed that any cost of upgrading the existing non-radial system will be rolled into the tariff and recovered from all customers. All customers would share in the cost of any upgrade required to interconnect the Fording facility and all customers would benefit from a new source of generation in southern Alberta.

Fording recommended that the Board approve the proposed Article 9.2 in the Terms and Conditions as the removal of the uncertainty of what costs Fording would be responsible for
would remove one of the significant barriers towards progress in the development of generation in southern Alberta.

With respect to shallow system customer contribution policy Fording noted that one of the major changes in the transmission tariff has been to consider both electricity suppliers and consumers as customers of the transmission system, whereas previously only load customers were considered the only customer of the transmission system and paid for the bulk of the transmission costs. Fording stated that the customer contribution policy had not been updated to reflect this change in the Transmission Tariff.

Fording asserted that since both consumers and suppliers were considered customers of the transmission system, and both paid relatively equal rates for access to the transmission system, then both load customers and generators should receive the benefit of an equivalent investment policy.

Fording suggested there should be symmetry in the rates and investment policy to minimize any discrimination between customer classes. Generators should receive the same benefit of investment in customer related facilities as load customers, and as such the TA should contribute to the shallow system costs associated with new generation. Fording noted that article 9.5 excluded STS customers from receiving the benefit of investment in customer-related facilities. As these customers could, however, make long term commitments to the TA, Fording recommended that the Board direct EAL to amend the article such that STS customers would be eligible for investment in customer related facilities.

Fording also noted that it supported a simple and easy to understand approach to calculating the customer contribution, as proposed in Article 9.3.

In argument, Fording recommended that the Board approve Article 9, Customer Contribution Policy, as proposed by EAL. The new policy provided additional clarity regarding what costs a customer is responsible for and was an improvement over the existing policy.

Fording noted that there were no postage stamp provisions for supply customers and a new Customer Contribution Policy based on sound economic principles was required. If a new generator came on line and required a system upgrade, the cost of the system upgrade should be rolled into the overall tariff to the extent that the system upgrade benefits all Albertans.

The addition of new generation in southern Alberta would defer large capital expenditures in transmission facilities in the Edmonton to Calgary corridor. Some of the benefits of additional generation in southern Alberta included a reduction in line loss, an improvement in voltage support, and alleviation of pressure on the Edmonton to Calgary constrained path. Fording submitted that the cost of upgrading the non-radial elements be classified as system related costs and rolled into the tariff, as proposed in Article 9.2.

Fording considered that EAL's proposal provided certainty regarding cost responsibility for upgrading the system, reducing risk for a generation developer which, in turn, would put
downward pressure on end use consumer prices. Fording recommends the Board approve Article 9, Customer Contribution Policy as filed.

For customer dedicated facilities, Fording recommended that a supply customer should have the option of having the TA coordinate the construction, arrange for a transmission facility owner to finance the project, and have the customer pay for the actual cost of the project over time. This should be an alternative to the existing situation where the supply customer is responsible for the entire project.

2.7 Views of IPCCAA

IPCCAA did not take issue with EAL’s proposed customer versus system classification of costs with respect to the customer contribution policy. IPCCAA stated, however, that it would be unwise for the Board to accept it as anything more than a pragmatic approach that appeared to work for the present.

IPCCAA recommended that EAL should clarify the financial difference between “fairness” and “efficiency” in this area. Information should be provided on the amounts collected under the proposed policy and the issues should be re-examined in three years.

IPCCAA recommended that EAL’s proposed customer contribution policy be approved for implementation in 2001. It may be that it will become necessary to modify or replace that policy in future once its impacts become known. IPCCAA submitted that the customer contribution policy should apply equally to all demand customers of EAL and in particular to DISCO customers.

IPCCAA understood that its position on this particular matter was consistent with EAL’s.

2.8 Views of IPPSA

In argument, IPPSA submitted that retaining the Board’s $97.9 million placeholder for demand attachment costs was reasonable.

IPPSA further requested that the Board direct the TA to continue to subtract this cost plus the new “post 2000” costs from the amount to be split 50/50 between demand and supply customers.

IPPSA noted that the approach to cost allocation for 1999/2000 was born in absence of a cost of service study. IPPSA also noted that costs associated with Board’s $97.9 million allocation did, in fact, reflect some extension costs, as the entire revenue requirement for both transmission functions of ENMAX and ETI included both terminal and extension related costs. While indicative and approximate, IPPSA accepted the Board’s determination in this manner as expeditious and appropriate.

IPPSA remained concerned about the effect of future demand attachment costs on the DTS tariff. The inclusion of demand extension costs in the residual amount to be split 50/50 imposed cross subsidization on the STS customers, who pay 100% of their attachment costs. This was at odds with the criterion set out in Decision 2000-1, page 119, where the Board indicated:
Accordingly, the Board finds that generators should be responsible for some portion of the costs of the embedded transmission system, based on the criterion that the party who benefits should pay.

IPPSA submitted that effective expansion of the marketplace must be based on transmission tariffs that reflected costs possible, within prevailing social policy and without subsidy among classes of users.

IPPSA requested that the Board direct the TA maintain a register of attachment costs on a going forward basis and to record reductions where costs, through evolution of the system, have been designated to not form part of attachment costs.

IPPSA agreed with EAL’s efforts to bring clarity and consistency to a subject as complex as the “System versus Customer” differentiation. IPPSA supported EAL’s definition of “Customer” related costs, in conjunction with the adoption of IPPSA’s recommendations above suggested that suitable illustrations of the various applications of the policy be provided as an annex to the tariff for the future avoidance of doubt.

IPPSA did not support the views of AE that extensive involvement of the DISCO customer is required in determining whether costs are customer or system related. IPPSA noted that a commercial interface now existed that dulled decision making. IPPSA assumed that both the TA and DISCOs would endeavor to do the right thing from a societal perspective but this might not always happen. DISCOs might strive to serve customer needs at the least cost, but would ultimately seek to serve customers needs and the needs of its shareholders for a return on their investment.

A DISCO as a transmission “user” is an aggregator of wire services, providing the necessary infrastructure to connect loads and generators together and to the transmission system where the costs to do so directly would otherwise be prohibitive. In this regard, a DISCO is a “user” of the transmission system no different than a directly connected industrial customer. Both have business objectives, both have a desire to see the least contribution for attachment to the transmission network as this affects their cost structure.

IPPSA submitted that AE’s approach was similar to the TA reviewing the merits and economics of (for example) sodium chlorate production with a prospective transmission user to determine the contribution would be determined based on which customers were being sold sodium chlorate and who they were. IPPSA supported EAL’s approach that the exact same treatment should be afforded to all users in a clear unambiguous manner, particularly the DISCOs.

IPPSA recommended that the Board direct EAL to adopt the definition proposed by EAL for system versus customer cost classification.

Concerning EAL’s proposal to compensate non-utility owners of transmission substations on the basis of Equivalent to TFO Revenue (ETR), IPPSA supported EAL’s approach as fair and appropriate. However Article 9 is silent as to how this would function in respect of generation developers who have developed and own their own connection. The Article did not mention how
EAL will compensate a non-utility transmission owner who has, in essence, paid a full contribution to itself for attachment to the system. In cross examination, EAL indicated the fair treatment in respect of a generator-owned facility being tapped to serve other TA Customers would be that the asset would become a system asset and the owner would be compensated on an ETR basis.

IPPSA noted that there may be situations where a generator attaching to the system may choose to not own the attachment facilities but would be required to make a full contribution. In this situation, the contribution policy needed to recognize this treatment in the same manner by providing the exact same credit or rebalancing. The current approach outlined in clause 9.10 implied dissimilar treatment between connections provided by the TA versus those provided by the generator. IPPSA considered that TCE's recommendation on the "Rebalancing" Policy was a reasonable remedy.

IPPSA supported EAL's proposal to compensate non-utility transmission owners using an ETR type of credit. IPPSA requested the Board direct EAL to develop a separate credit schedule for compensating non-utility owners (including generators) for their ownership of transmission facilities on an ETR basis.

IPPSA submitted that clause 9.10 was biased toward administrative simplicity and failed to give adequate recognition to past contributions through the declining balance treatment. IPPSA supported the proposal of TCE that refunds of customer contributions should not be limited to 10 years, and should occur over the lifetime of the asset as long as the refunds are warranted in being appreciably over administrative costs. IPPSA requested that the Board direct EAL to adopt the recommendations of TCE for contribution refunds to customers, having paid a contribution to the TA.

IPPSA considered the TA's proposed capital credit calculation was reasonable under the circumstances. IPPSA submitted that the TA should investigate refinements such as that proposed by TCE in respect of "Price Cliff's" and other improvements outlined in TCE's evidence.

IPPSA considered that EAL's 2001 Contribution policy proposal, in respect of Dual Use and Customer Owned Substation credits, represented a significant change in credit level. IPPSA considered that the issue of what a Dual Use credit applied to was put in issue by the definition of "net contracted load" which was interpreted by the Board at page 10 of Decision 2000-34. The Board stated that only that portion of demand capacity, which exceeded supply capacity, should be eligible for a Dual-Use Credit. The Board noted that EAL described this situation as "net contracted load". However, EAL indicated their interpretation of "net contracted load" differed from that of the Board. IPPSA agreed with EAL's interpretation of "net contracted load". IPPSA submitted that the 2000 contribution policy applied to Dual Use and Customer Owned Substation had little time to operate and had been evolving while EAL submitted this "alternate proposal".

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29 Tr. p. 2226, ll. 13-24
30 Evidence of TCE, p. 15
31 Tr. p. 2230, l. 24 – p. 2231, l.13

32 • EUB Decision 2001-6 (February 2, 2001)
Maintenance of the status quo was a good compromise in order to provide the time necessary for the continued evolution of this issue.

IPPSA requested the Board to direct EAL to maintain the currently approved treatments of the Dual Use and Customer Owned Substation credits, subject to revisions to clarify the application of the term “net contracted load”, in accordance with EAL’s interpretation.

IPPSA, in reply, requested the Board to dismiss the proposal of AE and direct EAL to implement EAL’s definition of “system versus customer”. IPPSA supported EAL’s efforts to bring closure to the “system versus customer” definition issue and considered AE argument for “judgement” in contribution policy application to be self-serving and of recent vintage.

IPPSA noted the Cities’ comment that AE had never reduced the elements of its policy to writing in a fashion that allowed predictability of the policy’s operation and administration. Under the policy proposed by AE, they would continue to add to their transmission rate and, in doing so, cast the cost responsibility of this effort onto all transmission rate payers.

IPPSA submits that EAL definition of “system versus customer” ought to be approved, and that the position and argument of AE be dismissed.

IPPSA agrees with the FIRM Customers\(^{32}\) that identification of costs and apportionment of customer costs on dual-use radial lines was essential to the fair treatment of Demand and Dual Use customers. The issue of dual use is recent and has been afforded little time to operate and uncover possible problems. Furthermore, EAL has been afforded little time to digest the Board’s directions in respect of Dual-Use, as noted on pages 10 and 11 of Decision 2000-25.

IPPSA considered that EAL should be allowed to operate the existing “2000” Dual Use policy, respond to Board’s direction noted above and be given time to consult and develop remedies to problems which might arise. IPPSA submitted that the Board should direct the TA maintain the currently approved Dual Use and Customer Owned Substation credit policies and to continue to develop the historical context for the development of this policy.

IPPSA noted that EAL saw\(^ {33}\) some merit in making the contribution policy symmetrical. IPPSA supported this proposal and submitted that EAL’s efforts should be focussed on:

1) Adhering, to the extent reasonable and appropriate, to the current course for tariff design. Revisiting matters such as 50/50 cost responsibility and attachment cost responsibility may be appropriate in the future however, Alberta’s electric industry can ill afford to suffer additional uncertainty at this time.

2) Ensuring that cost allocation responsibilities are equitably established as outlined on Page 5 of IPPSA’s argument. Fair and appropriate cost allocation is essential to any meaningful discussions on symmetry.

\(^{32}\) Argument of the FIRM Customers, p. 3, Section 3

\(^{33}\) Argument of EAL, p. 9
3) Operation of the current “2000” policies for the Dual Use and Customer Owned Substation credits as recommended in IPPSA’s argument IPPSA recommended that further evolution of these policies and consultation based on issues arising from that evolution must occur before alternatives can be suggested.

2.9 Views of TCE

In evidence, TCE noted that the TA had chosen its new policy for classifying facilities as either customer dedicated or system to “simplify and remove considerable doubt and subjectivity from the system/customer related/classification decision”. TCE maintained that to date the classification of facilities as either “customer” or “system” had been largely a subjective, uncertain exercise undertaken by the relevant utility. While supporting the TA’s efforts to bring certainty and objectivity to the classification of facilities as either customer dedicated or system, there were, in TCE’s view, some deficiencies in the TA’s proposed classification.

TCE maintained that the TA generally distinguished between radial (customer dedicated) and “looped” (system) facilities. The TA recognized that “[where a second or a third customer of significant size requiring transmission-level service is currently or proposed to be served from the same radial line, then the common portions of the radially [sic] line will be classified as system related].”

Accordingly, the TA appeared prepared to classify as system those portions of a radial line serving two or more “significant” customers who are presumably at different PODs. TCE generally supported this position.

However, to avoid the reintroduction of unnecessary subjectivity into the TA’s classification and to be consistent with what TCE understood to be the intent of the TA’s classification, TCE recommended that the criterion of “significance” be clearly defined and limited to “transmission justified” customers. However, whether the second or third customer accessing transmission-level service on the previously dedicated radial facility was “significant” or not, the TA’s Terms and Conditions should be clear that a refund should flow to the original contributing customer when other customers were served from the previously dedicated facilities.

TCE noted that the TA did not appear prepared to recognize as system related those radial facilities serving one POD, even though the POD may itself be the point of delivery to multiple end-use customers. In TCE’s view this was consistent with the TA’s intention to be “impartial” as to the nature of the load served. TCE agreed that the TA should invest in transmission facilities to PODs with impartiality as to the number of customers on the downstream side of the POD. In other words, the TA should be indifferent as to whether a POD supplies one 10 MW customer, ten 1 MW customers or one thousand 10 kW customers (assuming they have the same aggregate load factor).

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34 EAL 2001 Phase I and II GRA, Tab 8 p.3 of 12.
35 TCE-EAL 12(b).
36 AE-EAL 7.
37 TCE-EAL 35(e).

34 • EUB Decision 2001-6 (February 2, 2001)
TCE considered the TA’s proposed policy is deficient in failing to consider reliability issues. TCE submitted there were three standards of reliability: substandard, standard and above standard. Standard reliability included average reliability and a band of acceptable standard of service above and below average reliability.

In TCE’s view, existing customers experiencing a substandard level of reliability (below the band of acceptable standard of service) should be recognized as having the right to compel the TA to bring their reliability standard up to standard levels (either above or below average reliability). Capital and operating costs required to bring service to existing PODs up to these, what should be regarded as, minimum levels, should be considered system costs and shared by all customers. Any customer, new or existing, desiring to have reliability above standard reliability, or, in other words, above the band of acceptable standard of service, should be charged the incremental costs required to achieve this level of reliability.

TCE further suggested that any facilities planned by the TA that exceeded the requirements to provide standard reliability to a customer and were initiated by the TA in order to benefit the system (for example to provide surplus capacity for future system growth through using higher voltage levels than required by the customer) should be deemed system. The TA should estimate the net present value of all system benefits of a facility built for an individual POD and deduct that amount from the capital cost of the new facilities before applying the investment levels in Section 9.3 of the TA’s Terms and Conditions.

TCE also commented that reliability could be affected by the degree of path redundancy, which could be the result of planning decisions or customer requirements, and therefore unrelated to geographic location. At pages 10-12 of its evidence TCE supplied five examples of how different loads could be served by the transmission system. The examples illustrated that a decision to construct transmission facilities either as a looped or a radial extension not only determined if the extension would be classified as a system cost or a dedicated cost but would also affect the degree of reliability experienced by the customer as well as the contribution paid by the customer. TCE maintained the examples showed that the decision of the TA, based solely upon their judgement, could result in a customer receiving not only reduced reliability (in the case of a radial line) but also having to pay a higher contribution for it.

TCE agreed that that one test of “system” was the provision of a looped line. However, it seemed unfair and unreasonable that a customer who was served from a radial line were faced with two problems. The first problem was being faced with the prospect of having its facilities deemed dedicated (and therefore being faced with the prospect of a significant contribution to those facilities). The second problem was being faced with service that will be less reliable than other customers being served though looped facilities. These other customers were of course not faced with a customer contribution as the looped facilities were deemed system.

In TCE’s view, any fair investment policy should restore equity between customers served on looped facilities and classified as system and those customers on radial lines. TCE understood the TA’s policy to be an attempt, in some respects, to restore this equity.
Where the TA’s policy failed, in TCE’s view, was in omitting to recognize and compensate for the disparities in reliability inherent in the facility configurations selected.

With respect to customer contributions TCE stated that, even if the investment policy was set appropriately to place the customers on radial lines on a level playing field with those on a looped line from a cost of service perspective, differences in reliability must still be accounted for. All other factors being equal, TCE suggested that customers served from a radial line should be entitled to more investment per kW served than those from a looped system because of their reduced reliability.

In the short term, TCE suggested that changes would encourage the right decision making and provide better price signals. TCE suggested that any customer connecting for less than $300 per kW (the approximate historical maximum investment policy for AE and for TransAlta prior to 1990), should be provided 50% of the savings in transmission system capital calculated on an annualized basis. With a sharing in the benefit, this would encourage customers to locate close to the transmission system and to only request facilities that match their reliability requirements.

In the long term, as reliability data becomes available to the TA, the TA should move to a system where customers were rewarded for accepting reliability levels lower than what they were entitled to and were paid a portion at least of the cost savings to the transmission system. For PODs supplying both load and receiving energy from a generation source, TCE stated the recommendations discussed elsewhere in its evidence would apply to the portion of the POD required to supply the load.

For purposes of determining its investment, TCE noted that the TA had proposed a Roll-in Ceiling under which the TA would invest $2 million for every 5-year commitment term after the first five years of customer commitment and up to a maximum of four terms.\(^{38}\)

In TCE’s view, providing interpolations between 5-year points could eliminate the “pricing cliffs” from the proposed policy. TCE believed the TA was prepared to incorporate this practice.\(^{39}\) In TCE’s view, this practice should be made express in the TA’s tariff.

TCE also considered it fair that customers prepared to stage their loads up or down should be accommodated in the calculation of the TA’s investment contribution by having the TA’s investment calculated based on the levelized annual revenue from the customer’s service over all staging periods with due regard to the changing levels of contract capacity over time. TCE believed the TA was agreeable to this method of calculating its investment.\(^{40}\) In TCE’s view this method should be made express in the TA’s tariff.

TCE noted that, at present, the TA’s tariff provided for an increased customer contribution if the customer subsequently intended to reduce its contract capacity (staging down) but did not provide for increased TA investment if the customer intended to increase its contract capacity

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\(^{38}\) Article 9.3 of Terms and Conditions.

\(^{39}\) TCE-EAL 14(c).

\(^{40}\) TCE-EAL 14(a & b).
(staging up). If it is fair for a customer to be charged should the customer subsequently reduce its contract capacity, TCE thought it was equally fair for the TA to reimburse the customer if it intended to increase its contract capacity. TCE believed the TA was prepared to incorporate this practice.

The same policy should apply to any customer subsequently determining to increase its commitment term. In this case, the TA should reassess the customer’s entitlement to receive a Roll-in payment under Article 9.3. TCE submitted these practices should be made explicit in the TA’s tariff.

TCE maintained that customer contributions related to utility assets that were normally recovered according to a Board approved cost of capital. As such, it was appropriate that recalculations of customer contributions should be based on a Board determined weighted average cost of capital, rather than on the 12% as proposed by the TA. (The 12% apparently included a provision for depreciation, operating expenses and income taxes.) TCE believed the TA has agreed that there was merit to TCE’s approach. TCE believed this approach should be incorporated into the TA’s tariff.

TCE commented upon the TA’s proposal to limit the rebalancing and refund of customer contributions to 10 years. TCE maintained that such refunds should not be limited to 10 years but should rather occur over the lifetime of the asset as long as the refunds were warranted in being appreciably over administrative costs. This was fair and if this did not occur, TCE claimed a customer had an unnecessary incentive to own the transmission facilities to ensure they have the maximum opportunity to be reimbursed for their investment. Allowing the TA the benefit of the doubt that a lifetime refund would create an administrative burden, the 10-year refund cap could be left in place for contributions under $50,000. Above that amount, the customer should receive a lifetime refund. TCE claimed the TA has said that it would support extending customer refunds to the life of the asset if there were sufficient customer support. TCE submitted refunds of contributions were a matter of fairness and should not depend on the number of customers supporting the refund. A few customers properly owed significant refunds should be sufficient justification.

TCE was particularly concerned with the TA’s proposal to return 100% of the contributions for the first 5 years and then to reduce the refund by 20% per year for the next five years. This refund schedule appeared arbitrary and unsupported. TCE recommended that contributions should be refunded on an amortization schedule using a 6% real discount rate over the life of the asset. The comparison between the TA’s recommended refund schedule and TCE’s proposal for a 35-year average life asset was shown graphically at page 16 of TCE’s evidence. The details of this calculation were shown in Appendix B of TCE’s evidence for various asset lifetimes.

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41 Article 9.6 of Terms and Conditions.
42 TCE-EAL 15(a).
43 See response to ENMAX-EAL 10(c).
44 TCE-EAL 15(c).
45 TCE-EAL 18(d).
PART D: CUSTOMER CONTRIBUTION POLICY

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In argument, TCE supported the TA’s proposal to classify the costs of providing looped service as system related. TCE disagreed, however, with the TA’s attempt to distinguish between “double radials” and looped service on the basis of where the second line reconnects to the transmission system.

TCE noted that the TA had taken the position that a second supply line should be considered a “double radial” rather than the completion of a looped service if the second line tied into the transmission system at about the same general location as the first leg. TCE maintained that the real issue was whether the second leg that completes the loop is required to provide adequate service, not the location of the second leg.

The location of the tie-in should be irrelevant to the determination of whether the facilities were system- or customer-related. The relevant factor was the reasons for the construction of the second leg. If the reasons for the construction of the second leg which tied into the system at the same general location as the first leg were the same as the reasons for the construction of a second leg which tied into the system at another location, both should be considered loops and system related.

TCE recommended that looped services should be deemed system (unless the looping was required by the customer and was not needed using the TA’s development criteria for second lines of supply). A loop was any service with two or more lines of supply to a POD. Whatever criteria was used throughout the system to justify the second line of supply should be applied in all cases, whether the second line of supply was physically close to the first line of supply when it reentered the main transmission system or not.

Under the above recommendation, only second legs requested by customers and not required when applying the TA’s development criteria for second legs would be considered to be customer related. TCE also submitted that when a radial facility became system through subsequent looping that it was appropriate that contributions made by the customer prior to looping be refunded (with appropriate adjustments for amortization) as of the date of the conversion to a looped connection.

TCE made a number of comments with respect to radial facilities. TCE noted that while the TA had maintained in general that all radial costs would be classified as customer related no one appeared to oppose the TA’s clarification that the addition of another POD on a radial line resulted in the common portion of the line being treated as system.

TCE recommended that, where a second or third customer of significant size requiring transmission-level service was currently served or was proposed to be served from the same radial line, then the common portions of the radial line should be classified as system related. TCE also recommended that shared portions of radial lines should be deemed to be system, whether shared by a POD or POS.

TCE recognized that transmission facilities were added in discrete steps (i.e. 69/72 kV, 138 kV and 240 kV). As a result, there cannot always be a perfect matching of load and transmission

46 TCE-EAL-12(b) and Exhibit 75, page 6, line 13 to page 7, line 1
capability.\textsuperscript{47} To address situations where the TA may decide to pre-build capacity beyond what was required to serve a particular customer’s load, TCE recommended that load forecasts be used to identify the need for such additional capacity. Any costs related to the additional capacity (whether looped or radial) would be deemed system.

TCE noted that as part of its development plan the TA may plan for new PODs and that the costs of these facilities would be classified as system. TCE also noted that there may be cases where an individual customer may want the facilities constructed before the date identified in the development plan. TCE suggested that to charge the customer the full cost of the project would be unfair as to do so would result in other customers getting a free ride and noted that AE had acknowledged this early in the development concept for a facility that “would have been built in the next 5(?) years anyway, even in the absence of the current identifiable customer(s) requesting the service, that the facility may partly be ‘system’ related.”\textsuperscript{48}

TCE therefore recommended that load forecasts be used to identify transmission projects and that individual customers be charged only for early system costs as customer related, as opposed to full project costs.

TCE stated that load forecasts should be based on load likely to occur on the balance of probabilities. Moving to either the extreme of discounting all future loads or assuming all potential area loads would proceed was sub-optimal.\textsuperscript{49}

TCE maintained that the TA’s proposal that the determination of system versus customer would depend on the development plan in place at the time the customer contracted for system access service, created an arbitrary cutoff date (when signing a System Access Service agreement) and another unnecessary pricing cliff\textsuperscript{50}. Further, if load was required to sign a System Access Service agreement before that load would be included in the development plan, unless two customers happen to sign System Access Service agreements at exactly the same time, which seems improbable, there would always be a first mover disadvantage for the first customer signing a System Access Service agreement. TCE claimed this was obviously unfair and would be a disincentive for the customer to sign such agreements.

Additionally, the development plan for any given area would only be as good as the degree to which the area had been studied,\textsuperscript{51} the degree to which customers in the area were willing to disclose their intentions and how recently the plan was prepared. Customers should not be prejudiced by the TA’s advertent or inadvertent delay in studying an area. Moreover, every effort should be made to remove or reduce pricing cliffs and the first mover disadvantage.\textsuperscript{52} TCE recommended that when loops were planned, the TA should use a 5 year planning horizon on a rolling basis, not one arbitrarily fixed at one point in time. Secondly, load forecasts should be

\textsuperscript{47} Transcript page 3279, lines 6 to 19
\textsuperscript{48} Exhibit 86, Attachment 2, Consideration 7
\textsuperscript{49} Transcript page 3349, line 24 to page 3351, line 21
\textsuperscript{50} The pricing cliff was described at transcript page 2034, line 8 to 2036, line 6 and page 2037, line 17 to 2038, line 13.
\textsuperscript{51} Transcript page 2775, line 24 to 2776, line 7
\textsuperscript{52} Transcript page 2038, line 14 to page 2039, line 23.
based on the TA’s assessment of most probable load growth and should not be limited to load signing a System Access Service agreement.

TCE stated that customers other than the customer triggering a cost can also benefit from the new facility and noted that the TA has acknowledged that extending two lines into a substation was now the standard. TCE also noted that, while acknowledging that the looping of systems at new substations was for the benefit of other customers, the TA has nonetheless taken the position that these costs should be borne by the new customer. TCE claimed this was not consistent with cost causation principles. Another important exception was the inclusion of the system benefits that could arise from the introduction of a radial line into an area. System benefits of a radial line could include such matters as reducing distribution costs to serve a customer and transferring load supplied by relatively expensive isolated generation to the transmission system.

To address the above TCE recommended that system benefits to customers, other than the customer triggering the new facility, should be attributed to system and deducted from total facility addition costs before the TA’s investment policy was applied. TCE also recommended that the TA investment should not exceed what it would cost to reliably supply a load as isolated generation.

TCE noted that its witness, Mr. Levison, had discussed the issue of “optional” facilities with the Chairman and Mr. Berg. Optional facilities were defined as those deemed above or excess to the utility’s base case facilities and therefore those facilities to which the utility’s investment policy did not apply. TCE suggested these must be clearly established before any investment policy could be applied in a clear, consistent and fair manner. TCE submitted that all facilities required to provide standard reliability levels should be classified as base case and therefore included within the TA’s investment policy.

TCE recommended that the TA be directed to clearly define those base case facilities to which its contribution policy applied, and all facilities necessary to bring service levels up to standard reliability levels should be considered base case. The proper identification or classification of optional facilities tied in directly to the issue of substandard and standard reliability levels.

With respect to reliability, TCE acknowledged that that there was insufficient information currently before the parties to adjust the contribution policy at this time to recognize the impact of reliability. However, the difficulty of the task should not foreclose starting the effort. TCE stated that the criteria used to decide which customers obtained relief to their substandard reliability were unknown. Nor was it clear what criteria was applied to customers seeking “above standard” reliability to determine when a customer contribution was required and when such above standard reliability was considered system or included in the “base case” of an interconnection proposal.

Without clarification of the effects of reliability on contribution policy, the default position was that the TA determining these matters at its sole discretion. This created further unnecessary and unwarranted opportunity for inconsistencies. Another related factor was that the TA’s sole

53. Transcript page 1481, lines 15 to 20
54. Tr. p.3306, 3338 to 3339 and 3351 to 3352
discretion could be used to decide whether a customer was worthy to receive a looped supply facility as the TA has acknowledged that the “configuration of the transmission network will have a significant impact on reliability.” TCE also noted that the TA further agreed that while it was difficult to reflect reliability considerations in a tariff directly, the decisions made by the TA would affect the reliability experienced by a customer.\(^56\)

TCE recommended that the Board direct the TA, in conjunction with the TFOs, to provide relevant POD related reliability information at the next tariff application of the TA to determine substandard, standard and above standard reliability levels. TCE also recommended that the release of this information include relevant reliability information for the PBR process.\(^57\) TCE also referred to Exhibit 86, Attachment 2, Consideration 8, wherein AE took the position that “If there is a reliability problem that will be alleviated with the new facility, then the facility may in whole, or part, be ‘system’ related.” Therefore TCE further recommended that facilities required to resolve reliability or adequacy issues, either on a customer or system level, should be considered system costs.

With respect to postage stamp concerns on the implementation of the contribution policy TCE noted a passage in Decision 2000-1\(^58\) wherein the Board dismissed EAL’s request to apply location-based system expansion relating pricing (SERP) and stated that contributions should relate only to the local connection costs of the system expansion. TCE respectfully submitted that an additional unequivocal ruling by the Board on the issue of whether section 27(2)(b) of the EU Act applied to customer contribution policies where the costs imposed related only to the local connection costs of the system expansion would be helpful.

TCE noted that, in the last proceeding with respect to the treatment of transitional customers, the Board disagreed with TCE’s request that transitional customers be able to choose between TA’s proposed investment policy and the existing investment policy. TCE also noted that AE had led evidence in the present proceeding to establish that the TA’s proposed contribution policy would result in significantly different treatment of customers in AE’s historical service area. While not agreeing that AE’s “real life” examples either correctly reflected the application of the TA’s proposed policy or the application of AE’s historical policy TCE did agree that customers may be treated significantly different under the proposed policy than under existing policies.

TCE submitted that harmonization of formerly disparate investment policies must logically result in differing treatment from the treatment under the former policies. Indeed, it was because harmonization of formerly disparate investment policies must logically result in differing treatment that TCE submitted that transitional customers should be permitted to choose between the TA’s proposed investment policy and the existing investment policies of the TA and the utilities. TCE again requested that the Board direct that transitional customers be permitted to choose between the TA’s proposed investment policy and the existing investment policies of the TA and the utilities.

\(^{55}\) Tr. p.1480, lines 3 to 13
\(^{56}\) Tr. p.1480, lines 14 to 21
\(^{57}\) Exhibit 75, p.9, Lines 4 to 5
\(^{58}\) Decision 2000-1, p.270
TCE reiterated the arguments from its intervener evidence with respect to contribution refund practices, claiming that the second or third customer (or any subsequent customer) accessing transmission level service on a previously dedicated radial facility should result in an appropriate refund to the original contributing customer. TCE recommended that customers making contributions over $50,000 should be entitled to refunds over the asset lifetime if other customers use the facilities paid for by the original contribution. TCE noted that the only main concern the TA had to such a proposal centered around the administrative costs of such a proposal. TCE submitted this concern was unfounded, pointing out that over last 75 years, a little over 5 PODs per year have been added. For the years 1999 and 2000, 6 and 7 PODs will be added in each year, respectively. TCE maintained that the administrative burden consisted of a few pieces of paper in a file but could involve millions of dollars for the affected customer and it might be many years before a second POD came on a transmission line to trigger the refund.

TCE noted that, other than Fording, no one, including the TA, appeared to oppose TCE’s proposed amendments to the contribution policy, as outlined in Exhibits 75 and 91. The amendments related to the Roll-in Ceiling, changes in contract capacity, and refunds of contributions.

TCE noted that AE appeared to believe that no DISCO POD ultimately serving a “community of users” should be charged a contribution because this would violate the postage stamp restrictions of the EU Act. TCE also maintained that AE believed that all PODs, not just PODs serving a community of customers, were DISCO PODs, and therefore presumably should not have to pay a contribution. TCE suggested this posed a dilemma for AE, as AE wanted to continue charging its large industrials significant contributions.

TCE agreed with the TA that, in order for the TA to be impartial, the TA could not look downstream of the POD and could not apply or refuse to apply a contribution on the basis of the number of customers served downstream of the POD. The choice was either to charge contributions to all PODs or to charge contributions to none. As stated by AE, all PODs were DISCO POD. AE stated that if from a cost causation perspective, customers had the same aggregate load factor and load, they ought to pay the same tariff unless a case could be made that these identical load characteristics have led to a higher cost on the system.

To get around this problem TCE suggested that AE must create the impression that PODs serving large industrials were somehow riskier or had a higher chance of not proceeding and leaving stranded costs for others to pay for. In doing so, TCE maintained AE has ignored measures such as long-term contracts, contract minimums and unrecovered capital clauses.

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59 Exhibit 75, p.7, lines 1 to 5
60 Tr. p.3270, lines 17 to 22
61 Tr. p.3269, lines 22 to 24
62 Tr. p.3270, lines 15 to 17
63 Tr. p.3270, line 26 and p.3326, lines 12 to 14
64 Tr. p.3271, lines 3 to 7
65 AE=EAL-7, TCE=EAL 35(e).
66 Tr. p.3098, lines 17 to 19
67 Tr. p.3100, lines 22 to 26
68 Tr. p.3098, lines 20 to 22

42 • EUB Decision 2001-6 (February 2, 2001)
already imposed to minimize the risk of larger customers leaving stranded costs to be recovered by other customers.

TCE commented regarding AE’s comparison of projects provided in Attachment 1 to Exhibit 86. TCE suggested that the Board should not put undue weight on analysis that examined only three projects. Furthermore, the analysis of Project #3 Algar/Marianna did not provide the full picture. TCE pointed out that AE acknowledged that in testing the TA’s policy at the PODs in question AE looked at incremental load only, ignored future projected load at the sites and confirmed that 4.2 MW of existing load would be downloaded from existing 25 kV facilities.71 TCE noted that the TA also conducted a “Customer Contribution Comparison” for both TransAlta and AE contribution policies.72

In reply, TCE disagreed with paragraphs 20 and 21 of the TA’s Argument. The TA noted that it proposed a 5 year planning horizon when customers sign a System Access Service (SAS) agreement. TCE stated that customers would not receive the benefit, if additional load were reflected in the 5 year planning horizon, the day after the customer signed its SAS agreement. Secondly, the TA proposed to include only loads of customers who have signed a SAS agreement in its Development Plan load forecasts.

TCE indicated that the rationale the TA gave for the rigid, arbitrary and unfair use of its Development Plan and planning horizon is that, in the TA’s view, it provided “a reasonable balance between the need for certainty and the need to protect the customer’s interests.” As noted in TCE’s Argument (pg. 7), the TA’s refusal to recognize anything but a signed SAS agreement as indication of potential area growth renders certain that the first customer who signs a SAS agreement will suffer first mover disadvantage.

TCE indicated that when loops are planned, the TA should use a 5-year planning horizon on a rolling basis, not one that is arbitrarily fixed. Second, load forecasts should be based on the TA’s assessment of most probable load growth and not limited to load signing a SAS agreement.

TCE indicated that customers would rather have the uncertainty of full future recovery than the certainty of no recovery. Moreover, if a valid argument could be advanced by the TA that TCE’s proposed use of the TA’s planning horizon on a rolling basis would be too costly, the customer seeking the benefit could be required to pay the increased costs of administering the plan on this basis.

TCE noted that, at paragraph 23, the TA stated that if a distribution solution were the most cost effective and a customer continued to request a transmission solution, the Roll-in Ceiling would be set at zero and the customer would pay 100% of the facilities cost. TCE submitted that, if a customer chose a transmission solution over a less expensive distribution solution, the Roll-in Ceiling should not be set at zero. Rather, the appropriate response would be for the customer to pay the difference between what the costs would be to provide service at the distribution level

69 Tr. p.3111, lines 9 to 12
70 Tr. p.3112, lines 11 to 18
71 Tr. p.3111, line 6 to p.3112, line 10, Exhibit 108.
72 TCE-EAL-41 (a)
and the costs of service at the transmission level plus any contribution for transmission service costs after applying the TA’s investment policy.

TCE noted that the TA, at paragraph 24, indicated that its proposed contribution policy is not “symmetrical” and that it “sees some merit in making the policy symmetrical”. TCE noted that, in the TA’s 1999/2000 hearing, the Board determined that there was no need for symmetry between generation and load but symmetry was important in regulated and new generation. TCE noted this was achieved, in part, by continuing the deemed connection charge to existing generation and having new generation responsible for all of the local connection costs. TCE submitted that reopening this issue would create additional uncertainty in the generation development market.

Concerning TCE’s proposals to reflect varying reliability levels, the TA claimed that there is “no agreement on how reliability should be measured and compared, let alone on whether it should be a factor in the contribution policy”. TCE acknowledged in argument that there is insufficient information before the Board to adjust the contribution policy to recognize the impact of reliability and that more study is necessary. However, the suggestion that there is insufficient evidence a) of the need of measuring reliability levels, particularly in the face of upcoming PBR, and b) as to how reliability should be measured, was wrong.

TCE noted the Cities support a reliability level study in argument:

It is clearly a relevant exercise with respect to the development of performance based rates and may assist in the further evolution of cost of service analysis for the development of fair and reasonable tariffs for transmission service.

TCE agreed with the Cities and recommended that the release of reliability information at PODs also include relevant reliability information for the PBR process.

TCE noted that the TA’s approach with respect to “negative” contributions “implicitly assumed that customers will make location choices based on the TA’s contribution policy” and claimed that “there is no evidence that this would be the case”. TCE opposed AE’s proposal to use the ability of a customer to respond to so called “locational signals” within a contribution policy as a basis to classify facilities as either system or customer related.

TCE noted that the Cities also disagreed with the “negative” contribution proposal. TCE disagreed with the Cities that its proposal was a symmetrical “collar”. TCE’s proposed “negative contribution” contribution proposal would not increase costs. The proposal would reduce overall costs by “incenting” customers to build closer to the system, or for the TA to construct less than the “base case” facilities. If the customer saved the system $1,000 of cost for base case facilities that would otherwise have been constructed, through relocation, reduced service levels or self-supply, the customer should share in those savings. It was unlikely the customer will be “incented” to save the system costs unless it shares in some portion of those savings. TCE noted that the Cities supported the TA’s contribution policy as a “reasonable compromise with respect to a difficult issue, which will provide an additional incentive to customers to make economic
choices”. TCE agreed in general but noted that this is the rationale of TCE’s proposed negative contribution.

With respect to TCE’s proposed refund policy, TCE attempted to recognize the potential administrative difficulties with its proposal by suggesting a cap of $50,000 below which the "lifetime refund" approach would not apply. If a cap approach were to be used, which EAL opposed, then it should be at least $2 Million. If the TA were required to go to such extremes, it should only be for substantial amounts. TCE noted that the TA rejected the policy while, at the same time, admitting it was fairer to the customer. The Cities supported TCE’s “fine tuning” of the TA’s refund policy to “avoid unfair or inequitable results.”73 However, the Cities remained concerned about the costs of TCE’s proposal.

TCE submitted there was no justification for the TA’s proposed $2 Million minimum cap. TCE submitted that the TA had blown out of proportion the administrative burden consequent to any adoption of TCE’s refund proposal. However, if the TA quantified the burden it says the TCE proposal would create, TCE submitted that the increased administrative cost could be paid by the customer benefiting from the longer and fairer refund policy. This would address the Cities’ concern of increased costs and concern of the TA.

The TA stated at paragraph 42 that it would accept TCE’s proposal “to make reciprocal the adjusted customer contribution based on revised commitment terms and revised Revenue Related Amounts where a customer intends to reduce his contract capacity”. TCE believed the TA meant to refer to revisions where the customer intends to increase his contract capacity.

TCE noted that the TA also stated that it would amend Article 9.6 of its T&Cs to use a Board-determined weighted average cost of capital rather than the 12%, if the Board believed this to be appropriate. While TCE appreciated the TA’s willingness to adjust its proposal to a Board-determined weighted average cost of capital, TCE proposed the further refinement arising from Board examination as “simpler and more robust”.

TCE therefore recommended the use of a 6% discount rate for both sharing contributions with new customers and recalculation of contributions for existing customers who are changing their contract capacity or changing their contract term. 74

With respect to AE’s Proposed “List of Considerations” for Customer versus System Designation for EAL’s 2001 Phase II Contribution Policy, TCE requested that the Board accept AE’s considerations 3, 7 and 8 proposed in Attachment 2. Furthermore TCE requested that the Board reject AE’s considerations 1, 2, 4, 5, 6, and 9 for reasons discussed below.

Consideration 1: TCE indicated that AE is correct in assuming that the greater the number of customers served, the greater the likelihood that facilities will be considered system. TCE stated that end-use customers downstream of the POD are not the TA’s customers but are the DISCO’s customers. TCE indicated that the number of end-use customers served by the DISCO is irrelevant to the classification of the transmission facilities constructed to serve the POD.

73 The Cities p.5
74 Undertaking response for tr. Page 3358, to Page 3359, (Exhibit 105)
TCE submitted that, whether costs are triggered by one or two customers or by the aggregate load of many customers, these principles should apply equally. TCE's submission that from a cost causation perspective, one 10 MW load is identical to one thousand 10 kW loads, has not been challenged.\textsuperscript{75} TCE noted that AE agreed that "customers in similar circumstances should be treated the same" and agreed to the "like treatment of like cases" is a principle of fairness.\textsuperscript{76} TCE submitted that AE violated this principle when it stated, "only end-use customers who, under its proposal, have been identified to have caused the need for transmission costs that exceed an approved roll-in amount, should make a contribution."\textsuperscript{77} TCE submitted it is clear from the EU Act that the customers of the TA are at the POD and POS level and therefore tariffs charged to customers who are similarly situated at each POD should be the same. TCE noted that AE attempted to justify its discrimination against one or two (or possibly up to ten) identifiable customers on the basis that these customers impose a greater risk on the system because "the load could disappear, and strand other customers with that cost."\textsuperscript{78} As well, AE acknowledged that the risk of stranded costs from large industrial customers is mitigated by long-term contracts, contract minimums and unrecovered capital clauses.\textsuperscript{79} TCE noted that AE recognized that non-industrial customers such as residential loads have no long-term contractual obligations to protect against stranded costs.\textsuperscript{80}

TCE submitted that AE did not identify any stranded costs resulting from large industrial customers that did not materialize or did not honor contractual commitments. TCE submitted there is no evidence to substantiate that additional customer contribution must be assigned to certain customers because they are riskier or could cause stranded costs.

**Consideration 2:** TCE indicated that AE incorrectly concluded that the number of customers of a DISCO downstream of a POD is relevant to the TA's contribution policy. TCE dealt with this matter further in response to Considerations 1 and 4.

**Consideration 4:** TCE considered that differentiating system and customer on the basis of whether "the individual distribution points of service (customer accounts) the facility will serve are all part of a related process", is flawed and should be rejected. TCE indicated that the real reason for Consideration 4 may be to treat those customers who can "pack it up and leave" as customer related.\textsuperscript{81}

TCE submitted that ownership of facilities had no bearing on the risk of loads creating stranded costs. Furthermore the longevity of an oil or gas field is largely a function of the economically recoverable reserves in the field and has little to do with who or how many companies own the wells and processing facilities. The evaluation downstream of a POD, as to how related a process is or who owns the facilities, is not grounds to determine whether a transmission facility should be consider system or dedicated.

\textsuperscript{75}TCE evidence found at Exhibit 75, page 7, lines 10 to 14
\textsuperscript{76}Transcript page 3077, line 6 to 17
\textsuperscript{77}TCE-AETA-5 (a)
\textsuperscript{78}Tr. p.3089
\textsuperscript{79}Tr. p.3089 to p.3090. Tr.p.3090. Tr. p.3098 to 3099, Tr. p.3099, p.3100
\textsuperscript{80}Tr. p.3098 to 3100
\textsuperscript{81}Tr. Pg. 3093 to 3094
**Consideration 5:** With respect to this issue, TCE noted that AE confused diversity of DISCO customers downstream of a POD with diversity among Transmission PODs. The former is not relevant to the TA’s contribution policy.

**Consideration 6:** TCE urged the Board to reject AE’s proposal that a customer’s ability to respond to a price signal constituted grounds for the facility to be treated as customer-related. AE stated that if a customer could “actually move that operation somewhere else, then that is one of the considerations that would tend or lead you to calling the extension customer, because they can actually do something about that signal.” TCE indicated that AE had a policy that looked like a “load repulsion” rate. TCE submitted that the ability of a customer to locate elsewhere in the world should be irrelevant to any fair contribution policy.

**Consideration 9:** TCE is unclear why AE proposed special designation as system just because an existing facility is approaching its maximum capacity. Nor is it clear how it is determined when one is “close to maximum” capacity. Without more clarity on these matters, TCE recommended the Board reject this consideration other than to say that expansion facilities should not be treated differently than greenfield facilities in decisions on system versus customer matters. AE stated that the TA’s contribution policy “should yield results that render the same average rates for all DISCOs (in accordance with EU Act 27(2)(b)).” This section stated that the rates set out in the tariff “must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system.”

TCE noted that this is not discriminatory for new customers who are imposing above average costs on the system to incur above average charges. To do otherwise would violate AE’s principle that a balanced contribution policy must limit “the amount of the costs rolled in such that extension costs that exceed the average are not unduly transferred to customers who clearly do not make use of them.” TCE stated that AE understood the principle, however it doesn’t want it applied if it has a negative impact on the costs to some of its customers.

TCE indicated that without a contribution, the investment for the community of users could exceed that afforded identifiable customers. If that occurred, “identifiable” large industrial customers cross subsidize other customers. AE acknowledged they had not adjusted their cost of service study to reflect variations in transmission investment to serve a single end-use customer and transmission facilities serving a community of users. TCE indicated that with the replacement of Electric Energy Marketing Agency (EEMA), there is no longer an opportunity to cost average within the Large Industrials, General Service and Residential/Farms groups. Finally, it appeared that AE contemplated a rider to recover transmission-related costs of the Senex project. Such a charge causes some the costs of some AE DISCO customers to be different than

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82/Tr. Pg. 3095  
83/EAL-AETA-4 (a)  
84/EAL-AETA-4, (a) (i)  
85/Tr. p.3361 to 3362  
86/Tr. p.2085  
87/Tr. p.3115
customers of other DISCOs. TCE submitted that the fairest way to resolve this issue and to avoid inappropriate "pioneering" is to apply the same contribution policy at the POD level to all users.

With respect to AE’s position that the TA’s proposal was inconsistent and did not protect the utility and its customers from the risk that such customers would have to bear the costs of a facility built for the benefit of a few customers, TCE noted that the TA’s policy does more to protect the utility and its customers from risks by applying the contribution policy to all PODs, not just PODs built for the benefit of a single or a few customers. The TA noted that in paragraphs 40 and 41, in the “absence of a contribution policy that charges DISCOs a contribution for multi-customer PODs, there is little discipline imposed upon the DISCO’s requests for transmission service.” The TA’s contribution policy imposed discipline at all PODs.

AE argued that: “... contribution policies are generally intended for facilities dedicated to end-use customers.” TCE did not dispute that, historically, contribution policies were developed for end-use customers in the context of fully integrated utilities. However, fair and reasonable contribution policies relevant to an unbundled industry needed to be developed.

TCE noted that ENMAX, in argument (page 2), submitted that the purpose of a Customer Contribution Policy should be to ensure that a new customer has access to the electric system on a fair, equitable and non-discriminatory basis, while at the same time, protecting the interests of existing customers. TCE noted that ENMAX had concerns with risk and that the TA hasn’t done enough to curtail the risk of stranded costs that new customers create for existing customers. TCE disagreed with ENMAX’s proposal that the TA mitigate the risk by assuming the discretion to impose “forms of security” (presumably such things as letters of credit) as a condition to system access.

TCE submitted that there was no evidence that ENMAX’s concerns were valid. As the TA noted, all existing customers were once new customers, and all new customers will soon become existing customers. TCE noted that there is no reason to discriminate between existing and future customers as proposed by ENMAX. TCE further noted in argument that there is no evidence that costs of facilities to serve one or two customers have been rendered stranded to a greater degree than have costs of facilities built to serve multiple customers.

TCE submitted that AE’s position EAL’s proposal was “arbitrary, as costs are attributed to system or customer simply on the basis of whether the POD is connected to a looped or radial line without regard to the purpose of a customer contribution, or various other considerations relevant to the system/customer determination” was wrong. AE ignored factors that may cause a radial line to be deemed to be system. AE stated that the “radial /looped consideration should not drive a contribution policy”.

Concerning AE’s position that “the Board to bear in mind that at the transmission level (as opposed to the distribution level) most expansion is for system growth”, TCE queried that, if that were true, why would it not be appropriate to design a contribution policy to extend system service to most new customers without requiring a customer contribution. TCE stated that AE supported its statement by referring to an information request response by the TA where it

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88 EAL-FIRM-1, IPPSA-FIRM-4, AE Argument, p.4

48 • EUB Decision 2001-6 (February 2, 2001)
acknowledged that most contributions at the transmission level should be zero. TCE also indicated, in its view, that AE did mischaracterize EAL’s investment policy by alleging an artificial unfairness when comparing the application of the investment policy between loops and radials, yet ignoring the second step in the radial process, the application of a roll-in formulae. The fairness of the investment policy must be taken as a whole, considering all the steps and the outcomes of applying those steps.

With respect to AE’s position that EAL’s proposal is, “unfair to end-use customers, as the proposed policy does not take into account relevant considerations which exist “behind the POD,” for instance in circumstances where numerous end-use customers are served from a single POD connected by a radial line”, AE provided no rationale to support its claim that the TA should look “behind the POD”. TCE agreed with EAL that “AE’s ‘wholesale customer’ and ‘end-use customer’ approach …is simply another way of stating AE’s position that DISCOs should not be subject to the contribution policy.

TCE stated that, in spite of AE’s objection to using loops as a definition of system, AE apparently agreed that looped facilities should be treated as system. TCE claimed that the debate centered around AE’s claim that radial facilities should be treated as system and if it is radial supply, they should be treated as customer related. If this approach were adopted, TCE considered that AE could promote projects that had little load and were not constrained by the roll-in formula. AE acknowledged that the TA’s roll-in formula was generous, but not generous enough if multiple customers are involved. However, if identifiable customers were involved, AE has no problem treating them as customer related charges under certain “circumstances”. TCE indicated that those circumstances were unfair, based on matters such as whether a customer can relocate somewhere else or not.

TCE noted that AE in argument indicated, “True system facilities (for instance, to serve diverse load behind a single POD) may consist of “radial” extensions, just as dedicated facilities for end-use customers may consist of a “looped” extension.” Even the FIRM Customers recognized that just because a POD serves multiple customers is not sufficient reason to classify that service as system. The FIRM Customers acknowledged that there must be provision for cases where the costs to serve that group of customers exceed some reasonable boundary conditions. While TCE disagreed with the FIRM Customers’ proposal that would provide a more generous boundary condition for their customers than other customers, the FIRM Customers were willing to accept that there must be boundary conditions for groups of customers behind a POD, not just individual customers behind a POD when attaching to the system.

With respect to AE’s position that EAL’s proposal was contrary to the postage stamp transmission rate principle, this argument had been addressed in TCE’s and in the TA’s Argument. TCE submitted that it would be helpful for the Board to provide further advice on the

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89 AE Argument, page 4
89 Tr. p. 3107 to p. 3108
91 Tr. p. 3071,
92 Tr. p. 3096
93 AE Argument p.5
94 FIRM Argument p.5
issue of whether section 27(2)(b) of the EU Act applied to customer contribution policies where the costs imposed relate only to the local interconnection costs of the system expansion.

TCE indicated that the purpose of a contribution policy is to provide a boundary condition between what is to be charged through postage stamp tariffs and to individual customers of the TA, which AE agreed with. The reason a contribution policy was required at all was to prevent excessive investment in transmission facilities that must be borne by the rest of the system. Albertans obviously cannot afford to build a 100 km transmission line to serve 50 -10 kW loads. 96

TCE considered that AE’s claim that EAL’s proposal would no longer average transmission rates, was false. TCE stated that the tariffs were identical in every area of the province. 97 What AE was really suggesting was that DISCO customers would see different rates but not at the POD level. The existence of a contribution policy ensures that rates seen by DISCO customers experience unaveraged rates after factoring in the contribution. TCE stated that this was not a violation of the postage stamp principal. Even if it were, it would have to be remedied for all customers of the TA, not just PODs with multiple customers.

TCE indicated that AE was aware that classifying all radial extensions as system is only the first step in the contribution process. The second step would be to apply the TA’s investment policy. Only after the application of that investment policy (which includes up to $6 million for the Commitment Term Amount for one POD along with the Revenue Related Amount) 98 would a contribution be required. If a contribution were required, it is because the cost to serve that particular POD (serving whatever number of customers downstream) is in excess of a reasonable level of investment. To seek an unlimited amount of investment for any customer is not reasonable and fair to other customers on the system who will have to subsidize that investment. TCE indicated that an investment policy prevents a level of “pioneering” unacceptable to the remaining customers. 99

TCE submitted that AE’s motivation was clear in their statement that “System costs are presently dispersed through the entire province. However, if EAL’s proposal were adopted, the system costs of radial lines serving PODs with multiple end-users would be distributed only through the DISCO service area.” 100 TCE stated that AE wanted all costs associated with PODs with multiple customers paid for by all customers of the Province, not just those benefiting from the POD. AE could achieve its objectives by asking for a more generous investment policy than the TA proposed, or perhaps eliminating the investment policy. AE was aware this would drive up costs to all consumers in the province. 100 AE wanted to preserve its policy that had excessively generous investment in PODs with multiple customers and offset these by ensuring that large identifiable customers pay a substantial contribution.

95 See TCE Final Argument p.10 and 11 and 21 and 22
96 Tr. p.1459 to p.1460
97 Exhibit 2, Tab 2, p.20 of 39, Paragraph 9.3
98 Tr. p.3361 to page 3362
99 AE Reply, p.13
100 EAL-AETA-4(a)(ii)
TCE noted that the FIRM Customers\textsuperscript{101} argued that a single-customer facility should be charged a contribution while PODs serving multiple customers should not. TCE indicated that this is a discriminatory practice. TCE stated that there is no reason for charging single-customers other than it “mirrors” current DISCO contribution policies. The FIRM Customers realized that a cap must be placed on POD level investments; therefore a price cap should be based on not being more expensive than a “distribution interconnection or isolated service.”\textsuperscript{102}

TCE indicated that the FIRM Customers’ position confirmed the inequity proposed by FIRM Customers and its desire to have single-customer facilities pay large contributions while not being willing to do so when PODs serving multiple customers have the same load characteristics. TCE stated that the Board should be mindful of the fact that single-customer facilities are paying postage stamp tariffs on the same basis as multiple customer PODs.

AE argued that because it is in a high growth area of the province, the TA’s policy would have “negative impacts on its customers.”\textsuperscript{103} TCE submitted that, to the extent that high growth in AE’s service area is driven by resource development, it is those industries that should pay the contributions under the TA policy. Neither TCE, IPPSA nor IPCCAA, objected to the general features of the TA’s investment policy for loads.

TCE submitted that AE’s reference to high growth was misleading. The main reason why high growth was a concern is that AE may be required to establish more PODs than other DISCOs. TCE stated that the issue was where PODs serve multiple customers. TCE indicated that there was no issue for PODs serving multiple customers where the cost to serve those customers is covered by the TA’s investment policy. AE’s real issue is the cost to serve multiple customer PODs where the load will not justify the expenditure. This class of PODs could occur in any service area of any DISCO. AE may have more than their fair share of this type of POD, however an investment policy is designed to ensure that unwarranted investment relative to load size does not occur. No customer of the TA, regardless of which DISCO served them or how many customers exist beyond the POD should be exempt from a reasonable constraint on the cost of serve them, including the investment in their supply facilities.

Concerning Fording’s position that the Board not accept TCE’s proposed amendment for Article 9.6, as it will cause an increase in uncertainty, TCE’s noted that its proposed amendment to Article 9.6 did not presume a recalculation of customer contributions. The TA’s proposal Article 9.6 prescribed such a recalculation but only when a customer reduces its contract capacity.

If recalculation created uncertainty, it already existed in EAL’s proposed Article 9.6. TCE’s proposed amendment removed the inequity of Article 9.6, which, as proposed, would force customers to pay additional contributions should they reduce their contract capacity. EAL would refuse to repay customers for contributions already made when customers increased their contract capacity and/or commitment term.

TCE noted that Fording also suggested the Board not adopt TCE’s proposed amendment to

\textsuperscript{101} FIRM Argument, p.5
\textsuperscript{102} FIRM Argument, p.5
\textsuperscript{103} AE Reply, p.13
Article 9.10, as it “differentiates the method of calculating refunds when the original customer contribution is less than $50,000”. TCE noted that the purpose of the proposed amendment is not to change the method of calculation if the original customer contribution is less than $50,000.00. Where the original customer contribution is less than $50,000.00, TCE proposed applying the TA’s presently proposed methodology. It is only where the original customer contribution is greater than $50,000.00, or greater than any threshold deemed appropriate by the Board, that TCE proposed that its more rigorous, and admittedly, more fair, calculation be applied.

TCE agreed with UNC that there are problems with EAL’s proposal but agreed that it represented a significant step in the right direction and reduced the likelihood of arbitrary and interpretation and application of the policy.

TCE requested that the Board approve the TA’s proposed contribution policy with those recommendations as detailed in TCE’s Final Argument and in this Reply.

2.10 Views of TransAlta

TransAlta did not object to the proposed contribution policy of EAL. This position is based on its understanding of the proposal that was set out in its argument.

However, TransAlta noted two additional matters not forming part of the contribution policy at this time arose during the hearing.

First, EAL brought up a ‘commercial generation’ concept\(^{164}\) that would be an exception to some of the parameters discussed above. EAL acknowledged the concept was a developing concept and what was raised in this proceeding was ‘only a first cut’. As well, even where the concept to be adopted, it would not be expected to come into play in the near future.

Moreover, were the concept to be implemented, EAL acknowledged that it would engage EAL in a generation planning role ‘which is clearly beyond its mandate’. TransAlta submitted that the Board’s decision on EAL’s contribution policy in this proceeding exclude approval at this time of the concept, definition and treatment of so-called commercial generation.

The second matter that arose was the specific treatment of facilities that fall within Industrial System Designations\(^{165}\) (ISD). While some of the parameters set out above would, in principle, be applicable to non-TFO facilities within an ISD, EAL acknowledged that differing and additional matters might come to bear.

EAL brought up an alternative concept of ‘wheel-through’ that would be explored in negotiations with owners of facilities within an ISD, including TransAlta Energy. EAL concurred that treatment of ISD facilities was a matter for negotiation in the specific circumstances. TransAlta agreed with that approach and did not attempt to pursue ‘negotiations on the stand’ in this proceeding.

\(^{164}\) Tr. p.2094-2099

\(^{165}\) Tr. p.2126-29

52 • EUB Decision 2001-6 (February 2, 2001)
TransAlta accordingly requested that the Board’s decision on EAL’s contribution policy in this proceeding reflect and encourage negotiations to determine the appropriate treatment of facilities within ISD’s. Therefore, IPPSA’s request for codification of compensation parameters for non-TFO wires owners when non-TFO facilities commence to be recognized as providing system service was premature. It was also premature for IPPSA to ask that such facilities be treated on the same basis as TFO wires owners. EAL and TransAlta were in agreement that further pursuit of these matters through cross-examination was therefore inappropriate.

The Board will have the opportunity to review and consider the arrangements that ultimately are so negotiated, for example in the application currently before the Board in respect of connection of the Muskeg River (Albian) plant to the system, using non-TFO facilities.

TransAlta submitted that the FIRM Customers’ proposal for proper apportionment of facilities costs in respect of dual use should be applied to all non-system, dual use customer facilities. To do otherwise would effectively reverse the current treatment of supply connection costs, and would invite gaming by contracting for a small amount of load to avoid otherwise-payable connection costs for supply.

TransAlta disagreed with TCE’s proposals to collect and use POD reliability information for purposes of determining, in the next EAL rate application, matters of “substandard, standard and above standard reliability levels”. TransAlta notes that, pursuant to the TFO T&Cs, such information is to be provided to the TA by the TFOs in any event. TransAlta submitted that it was premature to consider such potential complexities in TFO/TA tariff design, when one of the reasons for collecting the data under the T&Cs was to assess what a proper approach to measuring transmission reliability might be.

In reply, TransAlta noted that EAL indicated\(^{166}\) some discomfort with the current policy that supply customers were ineligible for investment in respect of local connection facilities. EAL did not propose any changes and none of the participants in the hearing who addressed this matter in evidence or in argument-in-chief have made a proposal to alter the current treatment. Accordingly, no change in the treatment of supply customer connection costs should take place at this time. TransAlta noted that at such time as local connection facilities (including those of supply customers) become used to provide service to a second POS or a POD, those parts - and only those parts - of the facilities so used will commence to be treated as system facilities. At that time, costs borne and contributions paid by the owners of those facilities will be rebalanced.

2.11 Views of UNC

UNC noted that EAL acknowledged during the proceeding that it is important that the TA cooperate with the DISCO, in evaluating whether new loads should be connected to the distribution or transmission system. UNC also noted that the TA does have an internal formal requirement that DISCOs be consulted or notified in all cases where it is technically feasible to connect to either the transmission or distribution system\(^{167}\). UNC submitted that the Board should include in its Decision a statement emphasizing the need for, and importance of, such co-operation. UNC

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\(^{166}\) EAL Argument, p.9
\(^{167}\) Tr. p.2149-50
considered that this would be helpful in dealing with potential, or actual, customers and with EAL, when faced with individuals who may not be familiar with EAL policy.

UNC acknowledged that EAL has done a great deal to reduce the potential for a variety of, and accordingly potentially arbitrary, interpretations of the Policy. UNC submitted that it was clear from the questioning during the hearing that more can and will have to be done. UNC urged the Board and EAL to continue to strive for clarity in the Contribution Policy and to monitor its implementation in the future to ensure that an acceptable level of clarity has been achieved.

3 VIEWS OF THE BOARD

The Board has summarized its findings into the following topics:

1. Compliance of the Proposed Contribution Policy with the EU Act.
3. Harmonization Issues
4. Looped versus Radial Concepts and Customer versus System Concepts
5. Impact of Customer Contribution Policy on Multiple Customer PODs
6. Classification to Supply and Demand Customer-Related Costs
7. Negative Contributions
8. Refund Policy
9. Roll-in Ceiling
10. Risk Associated with Serving New Demand Customers
11. Symmetry between STS and DTS
12. Discussion on Reliability
13. Other Items
   13.1 Construction and Financing of Local Customer Dedicated Connection Facilities
   13.2 Use of Load Forecasts to Identify need for Additional Capacity
   13.3 Cost of Advancement versus Full project Costs
   13.4 Use of a 5-Year Planning Horizon on a Rolling Basis
   13.5 Items Deferred to Phase I and II Decision

3.1 Compliance of the Proposed Contribution Policy with the Electric Utilities Act.

AE and the FIRM Customers raised concerns with respect to whether EAL’s proposed contribution policy contravened section 27(2)(b) of the EU Act. AE in particular argued that the proposed contribution policy would “unaverage” transmission rates across the province, contrary to the so-called “postage stamp” principle.

The Board dealt with a similar issue in the proceedings respecting EAL’s 1999/2000 GTA. In determining whether EAL’s currently proposed contribution policy is compliant with section 27(2)(b) of the EU Act, the Board considers it instructive to review its findings in relation to this issue in Decision 2000-1.
In Decision 2000-1, the Board considered whether EAL’s proposed location-based system expansion related pricing (SERP) and related customer contributions contravened section 27(2)(b), which provides as follows:

(2) The rates set out in the tariff

(b) must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system.

In its 1999/2000 GTA proceedings, EAL had argued that the location-based SERP portion of its contribution policy did not constitute a “rate” as defined in the EU Act and, therefore, was not covered by the prohibition in section 27(2)(b). The Board found that EAL’s tariff involved “hybrid pricing”; the rate portion of the tariff proposed a system-wide rate covering system capacity costs; the T&Cs portion of the tariff proposed a customer contribution.

The Board found as follows:

It may be reasonably concluded, however, that the ordinary meaning of “rates” would include all financial payments customers are charged for service provided by the TA. ...

The over-arching requirement in the EU Act for postage stamp rates does not allow for the implementation of a hybrid pricing structure which differentiates between load customers based on their location on the system.108

In the present proceedings, EAL again proposes a hybrid pricing approach, which includes both rates (in the strict sense) and customer contributions. If this hybrid pricing results in differentiation between owners of electric distribution systems as a result of their location on the system, it would contravene section 27(2)(b) of the EU Act and could not be approved by the Board.

In the Board’s view, EAL’s proposed contribution policy does not result in a hybrid-pricing scheme that contravenes section 27(2)(b) of the EU Act. That section requires only that the rates for owners of electric distribution systems not vary as a result of the location of their systems on the transmission system. It does not require rates for all end-use customers to reflect the same transmission rate component.

In EAL’s present application, the contribution policy is indifferent to the location of an electric distribution system on the transmission system. The policy proposes simply that the costs of any radial extension to serve a POD will be considered customer costs, while the costs of any looped extension will be considered system costs. The geographic location of the POD in the province—i.e., “on the transmission system”—is immaterial both to the determination of whether the costs of the extension will be considered customer or system costs and to the amount of the contribution.

108 Decision 2000-1, p. 270
For these reasons, the Board concludes that EAL's proposed policy does not contravene section 27(2)(b) of the EU Act.

The Board made the following observations about the appropriateness of customer contributions for load customers in Decision 2000-1:

The Board considers that customer contributions are suitable in circumstances where service to a customer may impose costs on other customers for which they should not be responsible. An appropriate contribution policy therefore provides a suitable balance to an unlimited obligation to serve by imposing economic discipline on siting decisions. It transfers the economic burden of connection of new customers from the utility and its existing customers to the new customer. In other words, it exerts some of the discipline of the utility's economics on the economic decision-making of the customer. The Board considers that customer contributions should relate only to the local connection costs of the system expansion. The deep system costs of expansion are properly the responsibility of all customers, form part of the utility's revenue requirement and should be recovered from all customers through rates.\(^{109}\)

In other words, the Board accepts that customer contributions may differ as a result of factors peculiar to particular PODs. These factors may include the load at the POD as well as the length and capacity of the customer connection serving the POD, without violating section 27(2)(b) of the EU Act.

AE argued that a "customer" cost under EAL's proposed contribution policy, which the DISCO would consider to be a system cost, would result in the "unaveraging" of transmission rates where the POD served multiple end-users. However, section 27(2)(b) of the EU Act does not require average transmission rates among end users. It only requires that the rates charged by the TA to the owners of electric distribution systems not vary as a result of their location on the transmission system.

The Board notes AE's argument that EAL's contribution policy represents a significant change in government policy that should not arise indirectly through amendments to EAL's contribution policy but should be a matter for government policy makers. AE noted that Mr. Marcus on behalf of the FIRM Customers also expressed this concern at Tr. pp. 3530-3531. The Board notes that it is a creature of statute and that if it has erred in implementing the Act the Government can act to amend the legislation to clarify its intent.

In the Board's view, however, the arguments of AE and other interested parties raising these concerns are relevant to whether the contribution policy will result in a just and reasonable TA tariff.

In considering whether EAL's proposed tariff is just and reasonable, the Board believes it should consider the impact of the proposed contribution policy on end users. This, however, is a

\(^{109}\) Decision 2000-1, p. 270
different question than whether the contribution policy contravenes section 27(2)(b), which the Board has concluded is not the case.

3.2 Just and Reasonableness of the Proposal. Provision of Certainty, Predictability and Objectivity.

A fundamental question that needs to be answered is whether or not the proposed contribution policy is just and reasonable and does it provide certainty, predictability and objectivity.

ENMAX submitted that the purpose of a Customer Contribution Policy should be to ensure that a new customer has access to the electric system on a fair, equitable and non-discriminatory basis, while at the same time, protecting the interests of existing customers. ENMAX appears to generally support the contribution policy.

The Cities support the initiative to introduce a policy it considers being fair, open and non-discriminatory. In addition, the Cities submit the TA should be impartial as to the number and identification of the customers to be served.

The issue of the number and identification of customers to be served, especially if they are downstream of a POD, attracted the attention of all intervenors. Most intervenors agreed with EAL that the TA is in the best position to apply the contribution policy and that the proposed contribution policy is fair and is able to balance interests of both the new customer and the existing customers.

AE and the FIRM Customers have maintained that the proposed policy may differentiate among DISCO systems based on geographic location, resulting in different rates for transmission service, for the same class of customer.

EAL and TCE have maintained that it did not matter whether there was one customer, ten customers or a thousand customers behind a POD.

With a view to what seems fair, the Board does not agree with AE at this time. If the Board were to agree, then it begs the question “How many customers does it take to be exempt from a customer contribution?” The Board recognizes that any attempt to answer the question may have an arbitrary aspect. The Board does agree that the matter should be dealt with in exceptional situations, as discussed later in this Decision. The concerns of AE and FIRM have resulted in the Board identifying a further related issue for owners of distribution systems within AE’s and UNC’s territories as discussed in Section 3.5.

Another issue related to the number of customers to be served is whether or not the contribution policy provides the desired economic discipline.

EAL believed that the contribution policy was consistent with the philosophy of Decision 2000-1 that a customer contribution “exerts some of the discipline of the utility’s economics on the economic decision-making of the customer.” EAL submitted that, in the absence of a contribution policy that charges DISCOs a contribution for multiple customer PODs, there is little discipline imposed upon the DISCO’s requests for transmission service. EAL was
concerned that if a DISCO is not subject to a contribution for a multiple customer POD, there is little to prevent a request for service for an end-use customer that is remote from the system and may be uneconomic to serve, even in the most liberal interpretation of policy. EAL did not believe that it would be reasonable to include the cost of a transmission extension in its rates where there is a cheaper distribution or isolated generation alternative available. In EAL's view, Article 9.4 ensures that the TA's existing customers will be protected from that eventuality.

EAL argued that its contribution policy is a vital means of providing the appropriate price signals at the interface of transmission and distribution. EAL further argued that applying the contribution policy and, if it is determined one is required, assessing a customer contribution against a DISCO for a new point of delivery, sends the right economic signal and is fair. EAL stated that if the DISCO is required to pay a customer contribution for a multiple customer POD, the DISCO has a number of options for fairly distributing those costs among its customers. The DISCO could allocate the cost of the contribution to one or more customers behind the POD, to all customers behind the POD or to all customers on its distribution system.

The Board is in agreement with the objectives set out in EAL's contribution policy and expects, in most instances, it will produce the right economic decision in a fair manner.

With respect to EAL's contribution policy, most intervenors agree that certainty and predictability has been accomplished, but there was less agreement with the goal of objectivity. AE argued that it "does not achieve the objective of protecting the utility and its customers from the risk that such customers will have to pay, through general rates, for a facility built for the benefit of only a single or a few customers".

To examine if customers may be at risk of paying for a facility that benefits only one customer, it is important to look at how the contribution policy is applied.

The contribution policy is used to determine what level of contribution is required to be paid by the demand customer to cover the capital costs that exceed a certain proposed threshold. The proposed threshold is determined by a formula that takes into account revenues and term. EAL argued that the proposed formula provides a predictable outcome and gives weight to revenues to be paid to the TA and to the term or longevity of the revenue stream. By taking into account the revenue stream and the term of the contract, EAL argued that the economic well being of all the existing customers is being taken care of and the risk is mitigated.

In determining whether or not the contribution policy is just and reasonable, the Board has applied a test that would see all demand customers, including DISCOs, in the same light. That would mean any customer should be able to approach the TA with their load information and their location and be given the same answer as to the cost to connect. If the load and distance to connect were identical then one would expect the cost to be identical.

The Board considers such a scenario to be an example of fairness and would judge it to be just and reasonable. If the contribution policy formula is then applied, one would expect the customer contribution level to be identical assuming the term to be the same. In a simple example like this,

110 Tr. P.2537.
each customer in question would be given the same information on which to base their economic decision. The Board accepts, subject to further consideration at a future date, that there is normally no need for the TA to look beyond the POD to apply the contribution policy.

This is not the same as saying that the TA does not need to concern itself with downstream details and information. The Board would expect DISCOs to cooperate with the TA, providing information to assist in the development of the 5-year and 10-year transmission development plans.

The Board notes that EAL anticipates that in the ordinary course, there would be discussion between the TA and its customer. The Board agrees that EAL is considered to be the decision maker, subject to any appeals or applications to the Board, with respect to the imposition or the amount of a customer contribution, whether for a single-customer POD or a multiple customer POD.

AE acknowledged that the approach used by EAL to determine the contribution was relatively simple and avoided the need to be subjective. However, AE also noted the policy created uncertainty with respect to whether an extension was considered to be radial or looped and that a level of discretion was included in the contribution policy.

By contrast, other interested parties generally observed there was greater certainty and the degree of discretion was such that there was greater objectivity and less subjectivity than in the previous contribution policy.

On the whole, the Board is persuaded that the contribution policy as proposed is just and reasonable and provides a reasonable degree of certainty, predictability and objectivity.

The Board also recognizes that, while the contribution policy achieves all these objectives, there may be room for improvement.

As noted by the Cities, they did not consider it perfect, nor did the Cities consider that the proposed policy would perfectly deal with every case that might be brought forward in a fashion that would be acceptable to all participants. UNC urged the Board and EAL to continue to strive for clarity.

In this regard the Board believes that there will be situations that will have a history or unique circumstances and the Board accepts that parties may ask the Board to adjudicate. The Board will address these issues later in the Decision.

3.3 Harmonization issues.

The Board considers that the harmonization issues, which require resolution, are as follows:

1) Ensuring the appropriate harmonization between EAL and DISCO customer contribution policies;
2) Ensuring that the contribution policy does not disturb proper planning; and
3) Understanding how the customer contribution policy will affect a customer’s decision in choosing whether to become a “direct” transmission-connected customer versus a distribution-connected or isolated generation customer.

To evaluate whether EAL has successfully harmonized its contribution policy with that of the DISCOs, the following words appeared in Decision 2000-1:

Concerning the size of the contribution, the Board considers that, as the DISCOs’ transmission utility, the TA’s investment policies should be as consistent as possible with those of the DISCO so that the TA’s costs flow through efficiently to end-users. In this respect, the Board notes that the DISCOs employ a revenue-based system to determine the amount of investment that the project will support, with 100 per cent contribution above that amount. The DISCOs require contributions only on the customer connection with the “backbone” system costs borne by all DISCO customers, consistent with the Board’s findings above. Other contribution-related policies should be harmonized with those of the DISCOs as much as possible to reduce interface problems between the DISCOs’ systems and the transmission system. The Board considers that such a contribution policy would minimize any transition problems associated with the tariff.111

The Board recognizes that, pre-TA, the DISCO customer contribution considered both transmission and distribution facilities through the operation of the integrated utility. In the restructured industry, the DISCO contribution, by definition, can only deal with distribution facilities. The transmission contribution is paid to the TA. Therefore, policies on the part of the TA and DISCO that are harmonized, as to principle, should provide the least discontinuity to customers during the period of transition to the two levels of contribution.

The Board is satisfied that, by following the Board’s direction to develop a contribution policy based on the concept of excess of project cost over supporting revenue for the connection of customer costs for customers, EAL has harmonized this principle sufficiently with that of the DISCOs through its Roll-in Ceiling discussed later. The Board does understand that adjustments may need to be made to the contribution policies of the DISCOs to account for the Board’s decision on EAL’s policy. The appropriate forums for addressing any changes are in DT proceedings.

The Board notes that EAL has incorporated system versus customer principles in its policy. The extent to which the radial versus looped distinction fits previous historical practice will be evaluated in another section. The extent to which EAL has successfully defined customer versus system portions of the system will determine the success of EAL’s harmonization.

The Board concludes that, in principle, EAL has performed the harmonization directed in Decision 2000-1 and will evaluate the details below.

111 Decision 2000-1, p.271
The Board considers that the total electric system needs to be planned with the appropriate mix of transmission and distribution facilities. Contribution policies of the various entities that must work together must not disturb proper planning. In this respect, it appears as if the various parties are sharing information needed to perform the planning function.

The Board encourages cooperation within the industry and the co-operation of customers as well.

The Board considers that EAL’s policy of looking beyond the POD for distribution-based solutions is a sound step towards optimizing the overall system planning process. Searching for distribution-based solutions to system expansion should ensure that, in most cases, the most economical solution would result.

The amount of the customer contribution required for connection to the transmission system rests with the TA as discussed earlier. In this regard, the Board rejects the suggestion of AE that the amount of customer contribution should be a joint decision between the DISCO and the TA. The Board rejects AE’s view that the DISCO should have an effective veto on the amount of customer contribution. The Board further considers that the distribution versus transmission decision may ultimately rest with the customer if the customer decides that the distribution system connection or isolated generation is more attractive.

Nevertheless, if a customer considers that the TA is not properly exercising its discretion to choose between distribution and transmission solutions, the customer can apply to the Board and may request the Board’s assistance through adjudication.

The necessary use by the TA of its discretion is also addressed in the sections in this Decision dealing with Refund Policy and Roll-in Ceiling.

Ensuring equitable treatment of customers is important to the Board. The Board considers that it is important that a new customer has clear choices as to the options available and the costs associated with the options.

If there are substantive differences between contribution policies of the TA and DISCOs, it may be the cause of inequitable treatment such as differences in the terms and level of contribution. The Board considers that when the DISCO and TA policies are properly harmonized, then the inequities are minimized and the customer will choose direct versus distribution connection based on appropriate technical and financial considerations.

The Board considers that a customer should not be unduly influenced by the contribution policy in selecting a service provider. This assumes that the new customer is not taking undue advantage of the service opportunities.

3.4 **Looped versus Radial Concepts and Customer versus System Concepts.**

The issues raised with respect to the looped versus radial definition for the purposes of determining when a contribution is necessary are as follows:
1) whether the radial versus looped definition is a suitable proxy for determining whether the facility is a system expansion or one that requires a customer contribution;
2) the status of the “double radial”; and
3) whether a radial line serving more than one POD should be considered “system”.
4) Reference to the five-year planning horizon

The Board notes that EAL has not included a definition of a radial line in Article 9 but would consider adding a definition of a radial line.

The Board considers that it would be helpful to include a definition of both “Radial” and “Looped” facilities in the T&C and the Board directs EAL to include such definitions in its refiling.

IPCCAA did not take issue with EAL’s proposed customer versus system classification of costs with respect to the customer contribution policy.

IPCCAA stated, however, that it would be unwise for the Board to accept it as anything more than a pragmatic approach that appeared to work for the present.

IPCCAA recommended that EAL’s proposed customer contribution policy be approved for implementation in 2001. It may be that it will become necessary to modify or replace that policy in future once its impacts become known. IPCCAA submitted that the customer contribution policy should apply equally to all demand customers of EAL and in particular to DISCO customers.

The Board considers that EAL has mitigated some of the uncertainty within its control concerning contributions by harmonizing its policy, to the extent possible, with that of the DISCOs. EAL has further reduced uncertainty within its control by picking a definition which, in the Board’s judgement, works in most cases.

The Board acknowledges that there are exceptions where EAL’s definitions may produce an awkward result. However, as noted by the Cities, there is less discretion involved in EAL’s proposal than in AE’s proposal. The Board would extend this comment to the modifications proposed by the FIRM Customers. In the Board’s view, EAL’s definitions appear to best describe the differences between system or customer expansions.

The Board considers that the examples presented by the various parties during the hearing were very helpful to the understanding of the intended application of the customer contribution policy and further identified situations where the policy may not work perfectly. However, the Board notes that some of the examples cited in the hearing where the policy appears to not work, appear to be exceptional circumstances. The Board believes that EAL would and should take note of all the circumstances and adjust the contribution policy, if necessary, in the future.

For example, if a Jasper line were ever to be considered, the required contribution would have to take account of the environmental restrictions that would be imposed on a power line located
within a National Park and the resulting possible cost impact. In addition, there are generating units in place in Jasper and, as a consequence, the line would have STS usage, if the units remain in place. The Board’s understanding of EAL’s policy is that under these circumstances, the Jasper line would be systemized, under EAL’s proposal.

If a line to Jasper becomes feasible, the Board expects both EAL and AE to evaluate all the circumstances surrounding the project, the benefit to the existing system and Jasper for connection and decide what deviation, if any, from the contribution policy may be necessary. If any variance from the policy were proposed, the variance would then need to be filed with the Board for approval.

TCE stated that only five to seven PODs are added on average every year. The Board does not consider it would be an undue hardship for EAL to examine each system expansion for exceptional circumstances. EAL has already stated that it will examine situations to determine where a distribution solution may be more cost-effective. In all exceptional circumstances, the Board would consider an application from EAL or from a customer for contribution relief.

With respect to the “double radial” line, the Board notes that these arise where the system connection is close or identical to the connection of the first radial line. The Board considers that it matters whether the second radial line is intended to provide reliability or to provide capacity. If the second part of the double radial line is put in to provide capacity, the Board considers that it is only fair that the customer(s) requiring that capacity pay whatever contribution is required to connect to the system.

The Board considers that very rarely would a “double radial” line be installed solely for reliability but, should the circumstances arise, the “double radial” line can be considered to be system and the costs borne by all system users. The Board considers that the circumstance of a “double radial” line being installed for both capacity and reliability may occur more frequently than for reliability alone.

The Board would expect that EAL would take the unique circumstances of these lines into account and to adjust the customer’s contribution to recognize the possible shared responsibility between customer and system financial responsibility.

The Board does not see a need to change the definition of a radial line where that line or a portion thereof serves more than one POD. The Board notes that the second POD may benefit from a lower contribution from the presence of the first POD and vice versa through the refund mechanism. For these reasons, the Board will not require EAL to redefine the portion of a radial line serving multiple PODS as system.

In view of the growing experience with the new policy and its interaction with the DISCO’s contribution policy, the Board directs EAL to address any needed changes to the contribution policy at the next GTA. Further, the Board directs EAL, before the next GTA, to prepare and make public brochures or guidance material to assist potential customers in understanding its contribution policy. The Board assumes that EAL will naturally file copies with the Board and parties for information.
Further, given the increased clarity provided by the examples examined in the Hearing, the Board directs EAL, in its refiling, to include appropriate examples, that include both narrative and diagrams, of the application of the contribution policy.

EAL stated that that when the TA’s Transmission Development Plan shows a proposed radial extension will be looped within 5 years from the date that a customer signs a System Access Service (SAS) Agreement for the radial line, no contribution will be required.

EAL further stated that it would be reasonable to amend the language in Article 9.2 to make explicit reference to the 5 year planning horizon. The following explains EAL’s intended approach. If a radial line were not planned to be looped within 5 years of a customer signing a SAS Agreement the customer would pay the contribution. The next annual update to the 5-year plan could show the radial line as being looped within five years of the customer signing an SAS Agreement. In that case, the customer would not be released of its obligations to pay the contribution. However, if the line were looped within the initial 5-year period, the customer would receive a refund of a portion of the contribution.

The Board agrees with EAL and the Board directs EAL in its refiling to amend Article 9.2 to make explicit reference to the 5-year planning horizon. In its refiling, EAL should clarify that the refund would follow normal refund policy.

### 3.5 Impact of Customer Contribution Policy on Multiple Customer PODs.

The Board acknowledges the concerns of the FIRM Customers and AE that the proposed contribution policy may result in a level and frequency of transmission contributions at multiple customer PODs that would create unjust disparities in the transmission system access costs included in each DISCO distribution tariff.

However, these concerns appear to be based on scenarios of what might occur if EAL’s proposed contribution policy is approved rather than on actual data that would demonstrate the effect of the proposal had it been in force over the past few years.

Notwithstanding the improvements that the proposed Customer Contribution Policy appears to provide, the Board is also concerned there is insufficient evidence to assess the impact of the policy when applied to PODs serving multiple customers. In particular, where there is a potential for normal and continued growth that could precipitate the need for additional transmission facilities, it is unclear what the impact on DISCO distribution tariffs will be.

In order to have empirical data, the Board directs EAL to provide at the next GTA, for each of the years 1998, 1999, and 2000, the following information for those multiple customer PODs that would have required a transmission contribution using the proposed contribution policy:

- the number of customers downstream of the POD,
- the initial (or reinforcement) cost of the radial line
- the transmission contribution

The above information should be supplied for each of the following:
• Each new multiple customer POD installed.
• Each existing multiple customer POD where increased capacity was installed.
• the impact that the above annual transmission contributions associated with multiple customer PODs would have had on that DISCO’s total annual transmission access payments.

The Board directs EAL to provide the above same information, at the next GTA, on an actual basis for each month in 2001 during which the new TA contribution policy was in place.

The Board is also concerned about the flow through that any transmission customer contribution will have on independently owned distribution systems such as those of Ponoka, Cardston, Fort Macleod, Municipality of Crowsnest Pass, and the REAs. The question is whether the transmission customer contributions for those independently owned distribution systems should be treated as average transmission system costs in each of the UNC or AE service areas or whether the cost should be passed directly through to the independently owned distribution system alone.

The Board considers the appropriate forum to deal with the impact on the transmission customer contribution on independently owned distribution systems within the UNCA service area is in the 2001-200X UNCA DT proceeding.

For the AE service area, the Board considers AE’s proposed refiling of its Phase 2 T&C required to implement the approved TA contribution policy, to be the appropriate forum to deal with AE’s proposed handling of transmission contributions associated with REAs. The Board understands that amendments to AE’s T&C may have to be considered.

3.6 Classification to Supply and Demand Customer Customer-Related Costs

EAL noted that the FIRM Customers recommended the use of the ratio of DTS/(DTS + STS) to determine the demand customer-related costs prior to applying the contribution policy.

The Board notes that EAL considered FIRM’s approach to be reasonable but expressed concern that this recommendation was not the subject of stakeholder consultation, nor was it the subject of direct evidence. EAL was concerned that the potential impacts on other customers have not been fully canvassed. EAL would be prepared to accept the refinement proposed by the FIRM Customers if there were no significant objection.

The Board notes that EAL has no objection to the FIRM Customers’ DTS/(STS+DTS) (and presumably STS/(STS+DTS)) formula to determine the demand customer-related costs and the supply customer-related costs for transmission facilities prior to applying the contribution policy, if there was no objections to the proposal. EAL’s initial reluctance concerning the FIRM Customers’ proposal appears to be that it was not discussed at stakeholder meetings or in evidence during the hearing.

112 Exhibit 165, ATCO Electric 2001-2002 Distribution Tariff Application
The Board is not aware of any strong objection and considers the FIRM Customers’ proposal reasonable to implement for the purposes of this Decision and notes that it can be reviewed at the next GTA.

Accordingly, the Board directs EAL to use the DTS/(STS+DTS) and the corresponding STS/(STS+DTS) formula to determine the demand customer-related costs and the supply customer-related costs for transmission facilities prior to applying the contribution policy.

The Board also agrees with the proposal to “systemize” connection costs when dual usage occurs and notes that this proposal meets with no objections from intervenors.

Accordingly, the Board directs EAL, in its refiling, to reflect, in its contribution policy, the proposal to “systemize” connection costs when dual usage occurs.

The Board notes that it is leaving open, to its main decision respecting EAL’s 2001 GTA, the appropriate formula to be used in the determination of the Customer Owned Substation Credit.

3.7 Negative Contributions

The concept of a negative contribution policy arises from the premise that contributions should be symmetrical to the extent that contributions due to extraordinarily high customer costs should be matched by credits for extraordinarily low customer costs. In other words, when customer investment is less than average, the customer needs to be compensated by the utility. Some utilities have rewarded some customers for locating on the transmission system where customer investment would be less than the average to serve that particular customer’s load.

The Board notes that this practice has not been consistent among the integrated utilities or with the municipal systems. Furthermore, the Board notes that utilities that practiced negative contributions in the form of investment credits have not had a consistent practice across customer classes.

The Board is of the view that contributions need not be symmetrical to the extent that contributions would, in certain cases, become credits. The Board considers that this form of symmetry in contributions would result in a system of location-based credits for demand customers, which were discussed and found to be inappropriate in Decision 2000-1.

The Board also agrees with EAL that negative customer contribution payments also result in higher costs for other system customers, either as increased rates, increased frequency and level of contributions for new extensions, or both.

Accordingly, for all of the above reasons, the Board rejects the concept of negative contributions.

3.8 Refund Policy.

The Board notes EAL’s agreement that Article 9 could be amended to make it more fair to the first customer that has paid a contribution, by refunding a portion of the contribution to the first customer when a second customer comes along and uses the same facilities to which the first had provided the contribution.
The Board supports EAL’s submission that such a procedure could be implemented as a business practice following stakeholder consultations to review the various mechanisms by which this could be achieved.

The issues raised with respect to refunds are as follows;

1) the 10 year limit on contributions;
2) refunds available from POS or dual usage of contributed facilities; and
3) the rate of interest, if any, to be paid on contributions.

Other than these issues, the Board notes that there is general satisfaction among intervenors with the principle of refunding contributions as the system develops.

EAL proposed that the refund policy would be 100% for the first five years, and then a straight-line decline with no refund available at the end of 10 years.

TCE has proposed to extend the terms of the contribution refund over the life of the assets. As TCE noted, transmission assets may have an extremely long life, possibly as long as 40 years.

However, the Board notes that the engineering life may not coincide with the actual life of the assets, which is more likely to vary with the customer’s need for the assets. This is especially true for the types of assets that may require customer contribution, for example, transmission lines to limited life resource extraction developments. In this case, the life of the line is based on the life of the development and not on normal life expectations. If the line has a shorter life than expected, TCE’s proposal could leave contributions unamortized.

On the other hand, the Board notes TCE’s submission that there are very few contributions called for in any given year and TCE’s position that it would not be too onerous to keep track of this relatively small number of situations. TCE argued that the dollars involved can be very large and significant to the parties involved. TCE argued that any contribution over $50,000 should be eligible for refunds beyond the 10 years proposed by EAL.

The Board agrees with EAL that the contribution should be eligible for full refund for the first five years. The Board also agrees with EAL that maintaining records for small projects or small balances may result in undue administrative costs that are borne by other customers for a relatively small financial advantage of a small number of customers.

To be fair to the parties making a contribution while at the same time protecting the interests of all customers, the Board does agree with TCE that it would be fair to refund contributions or a portion thereof, for a maximum period of twenty years for more significant projects. The appropriate level that should qualify was not clear from the positions of the parties.

Accordingly, the Board directs EAL, in its refiling, to revise its refund policy to achieve the following:
• the contribution should be eligible for full refund for the first five years as proposed by EAL
• For the remaining 15 years the contribution would be amortized on a straight-line basis with the remaining book value of the contribution being available for refund to the customer.
• Commencing in year 11, any project whose remaining balance is below $50,000 can be truncated for refund purposes and no further refunds would be due.

Further, the Board directs EAL, in the next GTA, to address any change in the recommended project cost threshold for refunds beyond the 10 year period or any administrative cost levy to compensate for the extra administrative cost involved. The Board accepts TCE’s argument that customers would be willing to pay for any incremental administrative costs. Accordingly, at the time this issue is addressed, the Board will consider whether the effective date for the requirement for customers to pay the additional administrative costs should be the effective date of the new contribution policy.

The Board is also concerned that the rigid application of the refund policy may result in unintended or inappropriate refund situations. A number of these situations were discussed during the course of the Hearing.

Accordingly, the Board directs EAL, in its refiling, to ensure an appropriate clause exists to provide EAL with the discretion to determine that a refund in a specific situation may not be given or that a refund may be deferred pending specified circumstances. A specified circumstance could include, for example, the lack of a demonstrated sustained operation of a new or unproven industrial plant. This clause should address the situation where a customer was denied a contribution refund under EAL’s discretionary authority but subsequently satisfactorily completed some specified probationary period. After satisfactorily meeting the criteria, the customer should be then eligible for an interim or complete refund.

Further, the Board directs EAL, in its refiling, to include a clause that provides for the ability of the TA to have a refund returned to the TA where it was demonstrated that an error or inappropriate refund was given.

It is understood that parties, after discussion with EAL, could appeal EAL’s decision to the Board.

TCE proposed Article 9.6 should be changed to provide reciprocal treatment of adjusted customer contributions in the event of revised commitment terms and/or revised revenue amounts. EAL indicated their willingness to include such a change. The Board considers that a reciprocal treatment is appropriate.

The Board directs EAL in its refiling to incorporate changes that reflect a reciprocal arrangement in the event of revised commitment terms and/or revised revenue amounts.

In Article 9.6 of EAL’s proposed T&C, EAL outlined its proposal when a customer reduces its contract capacity before the completion of its commitment terms. EAL required customers to pay
interest at the rate of 12% per year for the number of years between the date of the original customer contribution and the revised customer contribution where a customer reduces its contract capacity before the completion of its commitment terms.

EAL was prepared to use a Board-approved weighted average cost of capital rather than the 12%, if the Board believed this to be appropriate. EAL noted that determining a weighted average cost of capital may be difficult where TFO rates are set by settlement and no weighted average cost of capital is explicitly expressed.

The Board considers that the charge to the customer has to offset the costs that the TA is obligated to pay to the TFO in order to avoid leaving a stranded cost with other customers. EAL should also consider whether other O&M type costs are being incurred and ensure that these are being recovered as well.

The Board recognizes that at times no weighted average cost of capital is established. The Board notes that AE in its 2001-2002 DT Negotiated Settlement filed with the Board on November 24, 2000 (Clause 32) contains language that addresses a similar situation. The Board considers that there is a ranking that should be followed to determine the cost of capital if one from the specific TFO in question is not available. The ranking would be other TFOs regulated by this Board and then other DTs regulated by this Board. If no rate is available, the Board can be asked for a rate.

The Board directs EAL in its refiling to change Article 9.6 that reflects EAL’s recommendation of an appropriate discount rate to calculate adjusted customer contributions in the event of revised commitment terms and/or revised revenue amounts. In so doing EAL should consider that it pays transmission facility tariffs to both investor owned utilities and municipally owned utilities. Tax effects may have to be considered. The Board also considers that whatever is approved by the Board may be subject to amendment in the future in order to harmonize EAL’s contribution policy with that of the DISCOs.

Further, the Board directs EAL to include clauses to address the situation where a cost of capital is not available due to a negotiated settlement.

3.9 Roll-in Ceiling

The issues the Board will consider in this section are the level of the Roll-in Ceiling and whether the calculation is appropriate.

The Roll-in Ceiling is composed of two parts, one related to revenue and the other related to the term of the contract. The level of the Roll-in Ceiling is, therefore, the sum of the two components.

The Board notes that EAL’s proposal was not challenged on the basis of the level of the Roll-in Ceiling. The Board also notes that EAL claimed that the formula, combined with the simplified system definition, was expected to result in an overall level of customer contributions comparable with previous utility policies. In the response to information request ENMAX-EAL-10, EAL confirmed that the amount of the Roll-in Ceiling was developed by comparing the results obtained by the proposed policy to the contributions produced by the application of
existing DISCO contribution policies. The level of the Roll-in Ceiling appears to have been chosen as the result of a heuristic process in order to best harmonize with DISCO contribution policies and so that 80% of system expansion projects would not require a contribution.

The Board considers this to be a fair manner to set the roll-in level as it preserves a balance between the need of new customers for service without a need for subsidy from existing customers. Most new customers will not see a different cost of system connection than existing customers. Existing customers should not bear any extraordinary costs of system expansion. Accordingly, the Board approves the level of the Roll-in Ceiling.

The Board notes that in its argument, bullet 2 of recommendation 15, TCE stated that pricing cliffs in the TA’s investment policy could be removed by interpolating values between identified points. TCE proposed that the Commitment Term Amount should not be based on a series of 5-year commitment term “pricing cliffs”. Rather, “interpolations” between the 5-year points should be used. IPPSA submitted that the TA should investigate refinements as proposed by TCE.

The Board notes that EAL has indicated that it does not oppose the recommendation and was prepared to make changes to the policy to incorporate interpolations between the 5-year commitment periods. The Board also notes that no other party indicated opposition to these suggestions.

The Board considers TCE’s recommendation to be fair and reasonable and notes IPPSA’s support for a revision. The Board agrees that the proposed change would remove pricing cliffs.

Accordingly, the Board directs EAL, in its refiling, to change the Roll-in Ceiling policy to incorporate interpolations between the 5-year commitment terms to reflect the recommendation of TCE with respect to pricing cliffs.

On a related subject, the Board notes that TCE recommended that the TA should calculate the revenue-related portion of the Roll-in Ceiling based on the levelized annual revenue from the new service over all the commitment terms with due regard to the changing levels of contract capacity over time. EAL had proposed a revenue-related amount equal to three times the incremental levelized annual revenue from the new service. In Exhibit 91, TCE has provided suggested wording changes to Article 9.3 to reflect this recommendation.

EAL was prepared to calculate the revenue-related portion of the Roll-in Ceiling based on the levelized annual revenue from a new service over all the commitment terms, as proposed by TCE as long as the future increases in contract capacity are contracted at the time of the original commitment.

Similarly, the Board directs EAL, in its refiling, to revise the revenue-related portion of the Roll-in Ceiling to be based on the levelized annual revenue from a new service over the qualifying commitment terms, as long as the future increases in contract capacity are contracted at the time of the original commitment.
The FIRM Customers consider that the calculation of the Roll-in Ceiling should be based entirely on a set of escalating multipliers based on contract term. This proposal has the patina of harmonizing more closely to the DISCOs’ principle of revenue supported project cost.

However, the Board notes that EAL’s proposal contains one revenue-based component.

The Board also considers that the second component, the $2 million per commitment term, takes sufficient account of revenue risk and the size of future revenue streams. The Board would also note that under EAL’s proposal no investment is made by the TA for the first 5 year contract term. It is only the second, third, and fourth contract terms that attracts an investment of $2 million from the TA for each term. The Board recognizes that there is considerable judgement in a contribution policy and that there is no one right answer. Therefore, the Board is not convinced that the FIRM Customers’ proposal for calculation of the Roll-in Ceiling would harmonize any better with that of the DISCOs. In any case, the FIRM Customers have placed a caveat on their proposal that it not be applicable to DISCOs.

The Board finds that the DISCOs should be included in the TA’s contribution policy. The DISCOs take contributed capital in various forms from DISCO customers. The level of these contributions presumably contains a portion for expansion of the transmission system. The Board considers that the contribution policies of DISCOs would harmonize better with those of the TA if the DISCOs compensated the TA for expansion of the transmission portion of the system on their behalf. Therefore, DISCOs should be included in the TA’s contribution policy.

The Board does not accept the method of calculation of the Roll-in Ceiling of the FIRM Customers and accepts that proposed by EAL modified so as to base the revenue related portion on the levelized annual revenue from the new service over the qualifying commitment terms.

The Board considers that EAL, in unusual circumstances, could require parties to sign a contract for service of sufficient length to provide for the amortization of costs. At the same time, EAL may not provide the Roll-in Ceiling credit amount normally associated with the length of contract signed.

Further, the Board expects that the TA will use its authority under Clause 9.4 of the T&Cs to determine the Roll-in Ceiling to be zero in situations where warranted.

The Board considers that the TA should have the ability to use its discretion to deviate from the policy as appropriate. Some examples of situations that may require deviation are as follows:

- in uneconomic circumstances or unreasonably high economic risk projects,
- the expected life of the project is shorter than the term of the contract that the customer is willing to sign and the financial capability of the customer is not established.

Accordingly, the Board directs EAL, in its refiling, to include revised wording in the Terms and Conditions that provides for the necessary authority for EAL to deviate from the established contribution policy.
It is understood that parties, after discussion with EAL, could appeal an EAL decision to the Board.

3.10 Risk Associated with Serving New Demand Customers

ENMAX submitted that the proposed policy of the TA did not adequately address the risk associated with serving new demand customers.

During the hearing, EAL proposed to mitigate the risk by exercising considerable discretion in determining the Roll-in Ceiling. ENMAX noted that there was no provision in the Customer Contribution Policy that provided the TA with this discretion to limit the contractual term.

Even if the TA were able to exercise some level of discretion and limit a contractual term, ENMAX submitted it would not be enough to mitigate the amount of risk to which the TA is exposed and would ultimately seek to pass on to its customers.

ENMAX noted that during the time of construction of facilities to serve a new demand customer, the TA does have considerable discretion over what forms of security it may seek from the customer under Article 8 of the Terms and Conditions of the Tariff. However, once construction is complete, and the facilities are put into service, the security that the TA had is no longer available. ENMAX argued that this loss of security places the TA and remaining customers at risk for what may be many millions of dollars.

To mitigate this risk, ENMAX proposed that Article 10 be amended as follows:

1) Article 10 should be amended to provide the TA with discretion over what forms of security it will accept to mitigate the risk that a customer might abandon service and create the potential for stranded costs; and

2) Article 10 should be amended to provide the same level of security that the TA might require during the construction of new facilities, as contemplated and provided for under Article 8 of the Terms and Conditions of the Tariff.

EAL noted that the ENMAX recommendations for amendments to the T&C were not raised in direct evidence but through cross-examination and ENMAX's opening statement. EAL noted that the concept was simple, get more security, but the practical implementation was not so simple. Requiring additional security, such as letters of credit or performance bonds over long periods of time could have significant impacts on customers which have not been debated in the consultations to date.

TCE noted that ENMAX, in argument (page 2), submitted that the purpose of a Customer Contribution Policy should be to ensure that a new customer has access to the electric system on a fair, equitable and non-discriminatory basis, while at the same time, protecting the interests of existing customers. TCE noted that ENMAX had concerns with risk and that the TA hasn't done enough to curtail the risk of stranded costs that new customers create for existing customers. TCE disagreed with ENMAX's proposal that the TA mitigate the risk by assuming the discretion

\(^{113}\) Tr. p.1157, lines 1-8.
to impose “forms of security” (presumably such things as letters of credit) as a condition to system access.

TCE submitted that there was no evidence that ENMAX’s concerns were valid. As the TA noted, all existing customers were once new customers, and all new customers will soon become existing customers. TCE noted that there is no reason to discriminate between existing and future customers as proposed by ENMAX. TCE further noted in Argument that there is no evidence that costs of facilities to serve one or two customers have been rendered stranded to a greater degree than have costs of facilities built to serve multiple customers.

The Board notes that EAL suggested it can use the following measures to mitigate the risk associated with serving new customers:

- Carry out a credit check on the new customer
- Determine the Roll-in Ceiling consistent with the number of commitment terms the customer is prepared to make and the results of the credit check

Although the Board has sympathy with ENMAX’s concerns, the Board agrees with EAL and TCE that the issue was not sufficiently explored in the hearing to understand the impacts and to be fair to those parties affected by a change.

The Board accepts EAL’s position that the above measures are adequate to mitigate the risk associated with serving new customers for the purposes of this GTA.

The Board notes the comment by ENMAX that there was no provision in the customer contribution policy that provided the TA with the discretion to limit the contractual term. The Board agrees that this discretion should be specifically authorized in the contribution policy.

Accordingly, the Board directs EAL, in its refiling, to amend the contribution policy to clarify that EAL has the discretion to limit the contractual term in order to mitigate the risk associated with serving new demand customers.

The Board agrees with EAL that the ENMAX proposal be deferred until the next GTA prior to which it could be discussed in the stakeholder consultations and more fully addressed in evidence.

Accordingly, the Board directs EAL, at the next GTA, to address the proposal to amend Article 10 to provide the TA with discretion over what forms of security it will accept to mitigate the risk that a customer might abandon service and create the potential for stranded costs.

3.11 Symmetry between STS and DTS

IPPSA and Fording raised this issue and EAL agreed that, while the current proposal is not symmetrical, the issue has merit. TCE and TransAlta took the position that the contribution policy should not change, as a result of these proceedings, from the findings of Decision 2000-1 on this matter.
The Board notes the suggestions, in IPPSA’s words, that resolution of this issue focus on:

- Adhering, to the extent reasonable and appropriate, to the current course for tariff design.
- Ensuring that cost allocation responsibilities are equitable.
- Operation of the current “2000” policies for the Dual Use and Customer Owned Substation.
- Establishing effective compensation practices for generators and other non-utility owners of transmission facilities for those facilities that become “systematized”.

The Board is of a similar view that the current proceedings are not a suitable vehicle for making the contribution policies for STS and DTS rates symmetrical. There was little evidence that would lead the Board to conclude that the current contribution policy required change.

The Board notes TCE’s views that, in the TA’s 1999/2000 hearing, the Board determined that there was no need for symmetry between generation and load but symmetry was important between regulated and new generation. TCE noted this was achieved, in part, by continuing the deemed interconnection charge to existing generation and having new generation responsible for all of the local interconnection costs. TCE submitted that reopening this issue would create additional uncertainty in the generation development market.

Accordingly, the Board will address this matter upon application or intervention from parties in the normal regulatory process. The Board notes IPPSA’s suggestion that the Board require the TA to maintain a register of attachment costs on a go forward basis to ensure that cost allocation responsibilities are equitably established. IPPSA maintained that fair and appropriate cost allocation is essential to any meaningful discussions on symmetry.

The Board considers that EAL will undertake prudent record keeping without the need for a specific Board direction given the expressed interest of parties in this issue. The Board notes that EAL saw some merit in a symmetrical contribution policy. The Board did rule in the last GTA on this issue and sees no need to address the issue further at this time.

3.12 Discussion on Reliability.

Reliability is not an issue that is directly related to the question of contribution policy. The indirect relationship is that, as a result of EAL’s solution to the system versus customer definition, the customer who is required to make a contribution to obtain transmission service may be obtaining a service that is less reliable than the system average. This is because a radial line, which EAL has chosen to define as a customer connection, is inherently less reliable than a looped line, which EAL has chosen to define as system. To some parties, this has the appearance of unfairness, which some parties have attempted to address by integrating reliability with the contribution policy.

On the matter of fairness, the EU Act does not require the TA to provide reliability on a postage stamp basis. In fact, the EU Act is silent on matters of reliability and assigning responsibility for ensuring customer reliability.
Furthermore, the TA, the TRANSCOs and the DISCOs generally state in their terms and conditions of service that they do not ensure 100% reliability of their service. The TA’s, the TRANSCOs’ and the DISCOs’ disclaimers are not made with any relationship to any contribution the end-use customer may make. At the end use customer level, reliability is not delivered on a postage stamp basis. The end-use customer may even require investment in standby generation in addition to the investment and whatever contribution the TA or the DISCO may require.

The Board has generally recognized that 100% reliability is not cost-effective and the Board, the utilities and customers have historically tolerated a reliability to cost of service tradeoff. The fairness surrounding reliability has not been an issue historically and seems to have become an issue with the development of performance-based regulation.

EAL noted that the relationship between reliability and rate design, including contribution policy, will be the subject of upcoming stakeholder consultations on the TA’s rates as well as between the TA, the TFOs and stakeholders for TFO PBR discussions. EAL considered discussion of the potential application to the contribution policy of unidentified reliability criteria to be premature and not suitable for consideration in this proceeding.

The Cities noted TCE identified another issue that may have some future significance, which is that differences in level of reliability should result in differences in rates paid by the customers. The Cities agreed that there may be different levels of reliability and that, over time, customers may be prepared to pay for different levels.

The Board considers that the reliability issue should be addressed as a matter of total rates and performance objectives and not only in the context of contribution policy and system expansion. It appears as if EAL and interested parties agree that the current proceedings do not have sufficient definition on the elements of reliability and its effects on system cost to incorporate reliability into contribution levels or overall rates.

Therefore, the Board will not place any reliability objectives upon EAL in these proceedings.

However, the Board directs EAL to develop, with the TFOs and with customers, a set of reliability objectives for the transmission system, the means for measuring them and the means for identifying which customers at which locations are most affected by reliability that does not meet objectives for consideration at the time of the 2003 GTA. These reliability objectives should be incorporated into the system of objectives that EAL sets for itself for 2003 GTA Phase I purposes.

These objectives should include the following:

- readily measurable, i.e. the data must be available at reasonable cost
- the objective must be set at a reasonable cost to reliability tradeoff point
- the means, if any, by which affected customers are identified and located
The Board considers that the reliability data collected by the TFOs and the TA should be kept in a format suitable for use in performance-based regulation.

With the restructuring of the electric industry, the responsibility for reliability is now dispersed among several players. The Board directs EAL and stakeholders to define responsibility for reliability objectives between the TA and TFOs, when developing objectives for the transmission system.

3.13 Other Items

3.13.1 Construction and Financing of Local Customer Dedicated Connection Facilities

Fording recommended that a supply customer should have the option of having EAL coordinate the construction, arrange for a transmission facility owner to finance the project, and have the customer pay for the actual cost of local Customer Dedicated Connection Facilities over time.

The Board notes that Fording has a number of options open to it pursuant to Section 4.5 of the Transmission Planning Guidelines issued by the Department of Resource Development on June 3, 1999. Section 4.5 reads as follows:

4.5 Customer Direction Regarding Ownership

Notwithstanding sections 4.3 and 4.4, a single customer at a single site with an individualized or totalized meter, shall have the right but not the requirement to choose to

(a) construct and own the transmission facility itself or through an affiliate; or

(b) instruct the Transmission Administrator to directly assign the ownership and construction of the transmission facility to a new or existing Transmission Facility Owner; or

(c) request the Transmission Administrator to hold a competition for the ownership and construction of the transmission facility in accordance with these Guidelines.

The Board notes that supply customers are fully responsible for the cost of local connection facilities. Further, the Board notes that EAL will arrange for a TFO to construct, own, and operate such assets in the absence of a direction from the supply customer pursuant to section 4.5 of the transmission planning guidelines. In this instance, the supply customer will pay a contribution equal to the cost of such facilities.

Pursuant to section 4.5(a), the customer can arrange the construction of and finance any local customer dedicated connection facilities necessary to connect its generator to the AEIS. In this case, the supply customer effectively becomes an unregulated TFO.
The Board is of the view that it is not necessary to order EAL to provide an option to customers for the coordination of financing and construction in order to achieve Fording's request. The Board considers that Fording's request can be realized through either of the following:

- Where a customer has chosen to own the local connection facilities, the customer can enter into commercial arrangements directly with a new or existing TFO. The customer would transfer its ownership position in such facilities to the TFO in exchange for a tariff, which would allow the customer to pay for the cost of the facilities over time.
- The customer, pursuant to section 4.5(c), can request the TA to hold a competition for the ownership and construction of the transmission facility with a condition that the successful bidder allow the customer to pay for the cost of the facilities over time.

Either of the above arrangements may result in a tariff, which effectively finances the project over an agreeable period of time.

However, the Board considers that this issue was not fully addressed by parties, including EAL and as such the record is not clear or complete on why Fording considered such a request necessary. The Board may not fully understand the concerns of Fording.

As well, Fording indicated that it would like the option to have the TA coordinate the construction of the customer connection facilities in order, as the Board understands Fording's position, to facilitate an efficient construction process.

The Board surmises that the issue is likely associated with Fording's interest in new large-scale coal fired generation. There is considerable public interest in facilitating and expediting decisions associated with such an application.

Accordingly, the Board advises Fording to continue to discuss this issue with the TA and the relevant TFOs and to raise this issue, if necessary, at the next GTA.

In the event that this matter requires more urgent resolution, the Board would consider, upon application by Fording, EAL or other interested party, handling this issue as an additional module to the 2001 GTA in advance of the 2002 GTA. In this manner, the Board can address any timing concerns of parties.

### 3.13.2. Use of Load Forecasts to Identify need for Additional Capacity

The Board notes that TCE has recommended (Recommendation 5) that load forecasts should be used to identify the need for additional capacity beyond that required to serve an individual customer, and any costs related to the additional capacity (whether looped or radial) should be deemed system. TCE claimed that if the TA chose, in anticipation of other transmission customer needs, to pre-build capacity beyond what was required to serve a particular customer’s load, the cost of the additional capacity should not be treated as customer related.

EAL has disagreed, stating that there was a risk in relying too heavily on load forecasts, citing the AE Ring Creek example. Additionally, EAL claimed the TCE proposal was an incentive to
game the system based on the “lumpiness” of transmission investment. There was too much incentive for the customer to understate its long term load requirements and rely on the ‘excess capacity’ to meet its requirements.

The Board notes that the transmission system must be planned such that adequate transmission facilities are installed to meet the forecast load growth at each POD. Proper planning includes a determination of the initial sizing of facilities, as well as the sizing of any reinforcements, required to meet the load forecast over the planning period of the Development Plan in the most economic manner. The Board considers that there is normally a minimum size of facilities that must be installed to meet the demand customer’s load forecast at each POD. In this case the Board agrees with EAL that the entire cost of the facilities, if radial, should be deemed to be customer.

The issue raised by TCE appears to go to the situation where transmission facilities are economically sized and built to meet forecast demand beyond the demand customer’s immediate needs forecast.

The Board is sympathetic with a concern that would foresee too strict an application of only signed SAS Agreements being used in Development Plans. The Board would see this as too restrictive and not enabling a useful 5 or 10 year plan being produced. The Board believes that the TA should have a view to possible and potential projects to create realistic, albeit potential, Development Plans.

In applying the contribution policy, the Board understands that a facility can be built that will exceed the requirements of the customer who is seeking service. This may arise due to practical economic reasons to do with incremental sizing of facilities or when taking into account the need for future capacity.

A situation that can arise when providing service to a new POD is that the radial line capacity will exceed the load of the customers’ requirements or even the customer’s reasonably foreseeable requirements.

The Board considers that the following to be a reasonable approach:

- in such an event, it seems reasonable that the customer cost and any contribution should be based only on the size of facility required to satisfy the customer’s requirements.
- When economics or system planning dictate a larger facility is to be initially installed, the TA would treat the additional cost of the ‘customer’ facility as ‘system’ until such time as growth or a second POD requires additional capacity.
- At that time, the TA would evaluate the need for an additional contribution based on the growth or incremental load that would utilize the built-in capacity.

It is also possible that the original load used to determine the contribution for the first customer POD was too low and the actual load served would have required a different contribution. Just as when considering a refund, it seems reasonable to the Board that the original customer should be
assessed an additional contribution in accordance with the contribution policy in the first place at the time the additional capacity is called for under the TA’s contribution rules. The Board considers that this should satisfy EAL’s concern that there was too much incentive for the customer to understate its long term load requirements.

A related situation can occur when a customer’s growth behind a POD gradually increases, such as with a community, to the point where a second radial line is necessary to continue serving the load into the future as the POD load continues to grow.

In this situation it seems appropriate to the Board that when reviewing the need for a contribution it is appropriate to take into account the total load, future considerations for growth and the entire facility. In these circumstances a strict application of the contribution policy may not be possible or practical and discretion by the TA will be warranted.

The Board directs EAL, in its refiling, to incorporate the following into its contribution policy:

- The method of assessing customer contributions in situations where economics or system planning dictate that a larger facility is to be initially installed, and the additional cost of the ‘customer’ facility is treated as ‘system’ until such time as growth or a second POD is required to be served.
- The method of assessing customer contributions where the original load used to determine the contribution for the first customer POD was too low and the actual load served would have required a different contribution.
- The method of assessing customer contributions where it is appropriate to take into account the total load, future considerations for growth and the entire facility at the POD.

3.13.3. Cost of Advancement versus Full Project Costs

The Board notes that TCE has recommended (Recommendation 6) that load forecasts be used to identify transmission projects and that individual customers be charged only for the cost of advancing project costs (or in other words early system costs) as customer related, as opposed to full project costs. TCE was addressing the case where an individual customer of the TA sought construction of the facilities earlier than the development plan. In this case, TCE believed that by simply bringing forward in time the construction of facilities already contemplated in the development plan, such a customer should not be charged the full amount of the transmission project. To do so would result in the other customers getting a free ride, according to TCE.

EAL has stated it understood this recommendation to apply where construction of a facility contemplated by the 5-year Transmission Development Plan was accelerated at the request of a customer. An example would be where a facility was forecast to be required in year five but a customer required the service in year two. In that situation, EAL understood TCE’s recommendation to be that the customer only be charged the costs of accelerating the construction. Presumably, these costs would include the time value of money and any incremental administrative costs, but not the cost of design, materials acquisition or construction.
EAL stated that, should its understanding be correct, the recommendation would be reasonable as long as it did not create uncertainty and time-consuming debate between the TA and the customer. If the TCE recommendation was to be implemented, EAL recommended that it be subject to the TA’s discretion to determine the applicable cost of accelerating the facilities.

The Board considers TCE’s recommendation to have merit and also agrees with the conditions that EAL has identified.

The Board directs EAL, in its refiling, to set out the method of assessing customer contribution in situations where it is appropriate for the cost of advancement to represent customer related costs rather than the full project costs.

3.13.4. Use of a 5-Year Planning Horizon on a Rolling Basis

The Board notes that TCE has recommended (recommendation 7) that when loops are planned, the TA should use a 5-year planning horizon on a rolling basis, not arbitrarily fixed at one point in time. Further, TCE recommended load forecasts should be based on the TA’s assessment of most probable load growth and should not be limited to load signing a SAS Agreement.

TCE noted the TA’s proposal that the determination of system versus customer would depend on the development plan in place at the time the customer contracts for system access service, created an arbitrary cutoff date (i.e. when signing a System Access Service agreement) and another unnecessary pricing cliff. The 5-year period commences when the customer signs the System Access Service Agreement. If a radial line is not planned to be looped within 5 years of a customer signing a SAS Agreement the customer pays the contribution. The next annual update to the 5-year plan could show the radial line as being looped within five years of the customer signing an SAS Agreement. In that case the customer would not be released of its obligations to pay the contribution. However, if the line were looped within the 5-year period, the customer would receive a refund of a portion of the contribution. EAL believed this to be a reasonable balance between the need for certainty and the need to protect the customer’s interests.

According to TCE, a demand customer might sign a SAS Agreement before that load would be included in the development plan. Therefore, unless two customers happen to sign SAS Agreements at exactly the same time, which seems improbable, there would always be a “first mover disadvantage” for the first customer signing a SAS Agreement. This “first mover disadvantage”, according to TCE, was obviously unfair and would be a disincentive for the customer to sign such agreements.

The Board notes that EAL has disagreed, stating that the customer paying the initial contribution was protected by the refund policy.

The Board considers that there are 2 matters to be addressed from its review of this issue as follows:

- The point that the clock starts for the refund period, including the initial 5-year period.
• If a customer is treated equally when the TA’s annual update shows a particular line being looped the day before a customer signs the SAS Agreement versus if the customer signs the SAS Agreement the day after an annual update shows the line being looped.

The Board agrees with TCE that there are elements of an unfair outcome in how EAL is proposing to implement the contribution policy although it is an indirect effect. The TA’s desire is to achieve and improve the reasonable balance between the need for certainty and the need to protect the customer’s interests.

The Board considers that there are mitigating measures that can be taken to reduce the unfairness while achieving the TA’s goals.

The TA proposed that the 5-year refund clock start at the time the customer signs the SAS Agreement even though the line may not be put into service for some period of time.

It appears to the Board that it would be equally reasonable to commence the start of the 5-year refund clock at the time the line is put into service or is available for service. This would introduce a much better sense of fairness and balance between customers who commit far in advance and thereby allow the system to be planned in a more economical manner versus the customer who requests the service in a very short period of time. It is more likely that funds will be disbursed in relation to the commencement date rather than the date of signing the Agreement.

Accordingly, the Board directs EAL, in its resiling, to revise its T&Cs to commence the start of the 5-year refund clock at the time the facilities are put into service or are available for service.

Further, the Board directs EAL, in its resiling, to submit the terms of the payment schedule for a customer contribution.

The Board will now address whether a customer is treated equally if the TA’s annual update shows a particular line being looped the day before a customer signs the SAS Agreement versus if the customer signs the SAS Agreement the day after an annual update shows the line being looped.

The Board can envision situations where the TA subsequently determines that a given investment will be treated as a system expansion after the TA has told the customer that customer contributions are required. In some cases, all payments by the customer may not have been made or received or not even started. Given the foregoing circumstance, it would seem unreasonable for the TA to actually require the cash be provided. Depending on the circumstances, the TA may waive or refund the contributions at that time or simply defer actually collecting the contribution.

The Board considers that the handling of contributions prior to the time the facilities are put into service is worthy of further examination at the next GTA and therefore, the Board directs EAL, at the next GTA, to submit revised practices for these circumstances.
3.13.5. Items Deferred to Phase I and II Decision

The Board notes that IPPSA mentioned some other matters as well.

IPPSA submitted that the Board should provide direction to the TA on the appropriate treatment of revenue requirement when dealing with the $97.9 million placeholder for demand attachment costs and new “post 2000” costs before a 50/50 split of costs between demand and supply customers.

IPPSA also requested the Board deal with compensation of generation developers who are non-utility transmission owners.

Finally, IPPSA requested the Board allow EAL to operate the existing “2000” Dual Use and Customer Owned Substation policy, giving time for the TA to address the related issues mentioned above.

The Board is of the opinion that all the above matters are not within the narrow scope of the Customer Contribution Policy, but raise issues that can be dealt with more appropriately as part of Phase II and can be addressed in that Decision. The views of parties expressed in argument and reply in this module will be imported into the Phase II decision.

4 REFILING

As a result of this Decision, it will be necessary for EAL to refile its proposed customer contribution policy.

The Board directs EAL to provide to the Board a proposed schedule for the refiling, including implementation of the approved contribution policy, within one week of the issue of this Decision.

5 SUMMARY OF BOARD DIRECTIONS.

The following summary of Board Directions to EAL is provided for the convenience of parties. In the event of any inconsistency between the Directions described below and those in the text of the main body of this Decision, the wording in the main body of the Decision shall prevail.

1. The Board considers that it would be helpful to include a definition of both “Radial” and “Looped” facilities in the T&C and the Board directs EAL to include such definitions in its refiling. [Page 62]

2. In view of the growing experience with the new policy and its interaction with the DISCO’s contribution policy, the Board directs EAL to address any needed changes to the contribution policy at the next GTA. [Page 64]

3. Further, the Board directs EAL, before the next GTA, to prepare and make public brochures or guidance material to assist potential customers in understanding its contribution policy.
The Board assumes that EAL will naturally file copies with the Board and parties for information. [Page 63]

4. Further, given the increased clarity provided by the examples examined in the Hearing, the Board directs EAL, in its refiling, to include appropriate examples, that include both narrative and diagrams, of the application of the contribution policy. [Page 64]

5. The Board agrees with EAL and the Board directs EAL in its refiling to amend Article 9.2 to make explicit reference to the 5-year planning horizon. In its refiling, EAL should clarify that the refund would follow normal refund policy. [Page 64]

6. In order to have empirical data, the Board directs EAL to provide at the next GTA, for each of the years 1998, 1999, and 2000, the following information for those multiple customer PODs that would have required a transmission contribution using the proposed contribution policy:
   
   - the number of customers downstream of the POD,
   
   - the initial (or reinforcement) cost of the radial line
   
   - the transmission contribution
   
   The above information should be supplied for each of the following:

   - Each new multiple customer POD installed.
   
   - Each existing multiple customer POD where increased capacity was installed.

   - the impact that the above annual transmission contributions associated with multiple customer PODs would have had on that DISCO’s total annual transmission access payments. [Page 65]

7. The Board directs EAL to provide the above same information, at the next GTA, on an actual basis for each month in 2001 during which the new TA contribution policy was in place. [Page 65]

8. Accordingly, the Board directs EAL to use the DTS/(STS+DTS) and the corresponding STS/(STS+DTS) formula to determine the demand customer-related costs and the supply customer-related costs for transmission facilities prior to applying the contribution policy. [Page 66]

9. Accordingly, the Board directs EAL, in its refiling, to reflect, in its contribution policy, the proposal to “systemize” connection costs when dual usage occurs. [Page 66]

10. Accordingly, the Board directs EAL, in its refiling, to revise its refund policy to achieve the following:
• the contribution should be eligible for full refund for the first five years as proposed by EAL

• For the remaining 15 years the contribution would be amortized on a straight-line basis with the remaining book value of the contribution being available for refund to the customer.

• Commencing in year 11, any project whose remaining balance is below $50,000 can be truncated for refund purposes and no further refunds would be due. [Page 68]

11. Further, the Board directs EAL, in the next GTA, to address any change in the recommended project cost threshold for refunds beyond the 10 year period or any administrative cost levy to compensate for the extra administrative cost involved. The Board accepts TCE’s argument that customers would be willing to pay for any incremental administrative costs. Accordingly, at the time this issue is addressed, the Board will consider whether the effective date for the requirement for customers to pay the additional administrative costs should be the effective date of the new contribution policy. [Page 68]

12. Accordingly, the Board directs EAL, in its refiling, to ensure an appropriate clause exists to provide EAL with the discretion to determine that a refund in a specific situation may not be given or that a refund may be deferred pending specified circumstances. A specified circumstance could include, for example, the lack of a demonstrated sustained operation of a new or unproven industrial plant. This clause should address the situation where a customer was denied a contribution refund under EAL’s discretionary authority but subsequently satisfactorily completed some specified probationary period. After satisfactorily meeting the criteria, the customer should be then eligible for an interim or complete refund. [Page 68]

13. Further, the Board directs EAL, in its refiling, to include a clause that provides for the ability of the TA to have a refund returned to the TA where it was demonstrated that an error or inappropriate refund was given. [Page 68]

14. The Board directs EAL in its refiling to incorporate changes that reflect a reciprocal arrangement in the event of revised commitment terms and/or revised revenue amounts. [Page 68]

15. The Board directs EAL in its refiling to change Article 9.6 that reflects EAL’s recommendation of an appropriate discount rate to calculate adjusted customer contributions in the event of revised commitment terms and/or revised revenue amounts. In so doing EAL should consider that it pays transmission facility tariffs to both investor owned utilities and municipally owned utilities. Tax effects may have to be considered. The Board also considers that whatever is approved by the Board may be subject to amendment in the future in order to harmonize EAL’s contribution policy with that of the DISCOs. [Page 69]

16. Further, the Board directs EAL to include clauses to address the situation where a cost of capital is not available due to a negotiated settlement. [Page 69]
17. Accordingly, the Board directs EAL, in its refiling, to change the Roll-in Ceiling policy to incorporate interpolations between the 5-year commitment terms to reflect the recommendation of TCE with respect to pricing cliffs. [Page 70]

18. Similarly, the Board directs EAL, in its refiling, to revise the revenue-related portion of the Roll-in Ceiling to be based on the levelized annual revenue from a new service over the qualifying commitment terms, as long as the future increases in contract capacity are contracted at the time of the original commitment. [Page 70]

19. Accordingly, the Board directs EAL, in its refiling, to include revised wording in the Terms and Conditions that provides for the necessary authority for EAL to deviate from the established contribution policy. [Page 71]

20. Accordingly, the Board directs EAL, in its refiling, to amend the contribution policy to clarify that EAL has the discretion to limit the contractual term in order to mitigate the risk associated with serving new demand customers. [Page 73]

21. Accordingly, the Board directs EAL, at the next GTA, to address the proposal to amend Article 10 to provide the TA with discretion over what forms of security it will accept to mitigate the risk that a customer might abandon service and create the potential for stranded costs. [Page 73]

22. However, the Board directs EAL to develop, with the TFOs and with customers, a set of reliability objectives for the transmission system, the means for measuring them and the means for identifying which customers at which locations are most affected by reliability that does not meet objectives for consideration at the time of the 2003 GTA. These reliability objectives should be incorporated into the system of objectives that EAL sets for itself for 2003 GTA Phase I purposes.

These objectives should include the following:

- readily measurable, i.e. the data must be available at reasonable cost
- the objective must be set at a reasonable cost to reliability tradeoff point
- the means, if any, by which affected customers are identified and located. [Page 76]

23. With the restructuring of the electric industry, the responsibility for reliability is now dispersed among several players. The Board directs EAL and stakeholders to define responsibility for reliability objectives between the TA and TFOs, when developing objectives for the transmission system. [Page 76]

24. The Board directs EAL, in its refiling, to incorporate the following into its contribution policy:

- The method of assessing customer contributions in situations where economics or system planning dictate that a larger facility is to be initially installed, and the
additional cost of the ‘customer’ facility is treated as ‘system’ until such time as growth or a second POD is required to be served.

- The method of assessing customer contributions where the original load used to determine the contribution for the first customer POD was too low and the actual load served would have required a different contribution.

- The method of assessing customer contributions where it is appropriate to take into account the total load, future considerations for growth and the entire facility at the POD. [Page 79]

25. The Board directs EAL, in its refiling, to set out the method of assessing customer contribution in situations where it is appropriate for the cost of advancement to represent customer related costs rather than the full project costs. [Page 80]

26. Accordingly, the Board directs EAL, in its refiling, to revise its T&Cs to commence the start of the 5-year refund clock at the time the facilities are put into service or are available for service. [Page 81]

27. Further, the Board directs EAL, in its refiling, to submit the terms of the payment schedule for a customer contribution. [Page 81]

28. The Board considers that the handling of contributions prior to the time the facilities are put into service is worthy of further examination at the next GTA and therefore, the Board directs EAL, at the next GTA, to submit revised practices for these circumstances. [Page 81]

29. The Board directs EAL to provide to the Board a proposed schedule for the refiling, including implementation of the approved contribution policy, within one week of the issue of this Decision. [Page 82]
6 ORDER

THEREFORE IT IS ORDERED THAT

1) ESBI Alberta Ltd. shall inform the Board on or before February 9, 2001 of its timetable for the refiling of the Customer Contribution Policy portion of its 2001 Phase I and Phase II General Tariff Application and its proposal for the implementation date of the new policy. ESBI Alberta Ltd. shall refile the policy as quickly as possible, incorporating the findings of the Board in this Decision.

2) The refiling shall be at a level of detail sufficient to reconcile with the original filing and to demonstrate compliance with the Board’s findings.


ALBERTA ENERGY AND UTILITIES BOARD

N. W. MacDonald, P. Eng.
Presiding Member

A. J. Berg, P. Eng.
Member

Member
APPENDIX 1

THOSE APPEARING AT THE HEARING

<table>
<thead>
<tr>
<th>Principals and Representatives (Abbreviation Used in Report)</th>
<th>Witnesses</th>
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<td>ESBI Alberta Limited (EAL)</td>
<td>David Erickson, Fergal McNamara, Randall Stubbings, Fred Ritter, Eamonn Duggan, Richard Stout</td>
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<td>D. A. Holgate</td>
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<td>ATCO Power (ATCO Power)</td>
<td>Robert Baer, Kris Sakowsky</td>
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<td>J. E. Lowe</td>
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<td>ATCO Electric Limited (AE)</td>
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<td>L. G. Keough</td>
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<td>Shannon Young</td>
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<td>S. M. Munro</td>
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<td>Alberta Urban Municipalities Association (AUMA)</td>
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<td>C. R. McCreary</td>
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<td>City of Calgary (Calgary)</td>
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<td>R. B. Brander</td>
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<td>P. Qinton-Campbell</td>
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<tr>
<td>Cities of Lethbridge and Red Deer (the Cities)</td>
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<td>Phyllis A. Smith, Q.C.</td>
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<td>ENMAX Power Corporation and ENMAX Energy Corporation (ENMAX)</td>
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<td>L. A. Cusano</td>
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<td>D. M. Wood</td>
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<tr>
<td>TransCanada Energy Limited (TCE)</td>
<td>Dan Levson, Vincent Kostesky</td>
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<td>M. S. Forster</td>
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<td>Resorts of the Canadian Rockies (RCR)</td>
<td>Neil Jackson, Dale Hildebrand</td>
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<tr>
<td>M. S. Forster</td>
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Industrial Power Consumers and Cogenerators
Association of Alberta (IPCCAA)
D. E. Crowther
Mark Drazen
Ron Mikkelsen
Dan Macnamara

Independent Power Producers Society of Alberta (IPPSA)
and Senior Petroleum Producers Association (SPPA)
L. L. Manning

TransAlta Utilities Corporation (TransAlta)
T. Dalgleish, Q.C.
Shauna Finlay

Alberta Irrigation Projects Association (AIPA)
J. H. Unryn

Utilicorp Networks Canada (UNC)
R. B. Wallace

Alberta Cogenerators Council (ACC)
R. C. Secord
Alan Rosenberg

City of Medicine Hat (Medicine Hat)
K. F. Miller

Powerex Corp. and British Columbia Power and Hydro Authority (POWEREX)
Cecilia A. Low

Fording Coal Limited (Fording)
Arnie Reimer
Sean Smyth
Arnie Reimer

Consumers Coalition of Alberta (CCA)
J. A. Wachowich

Public Institutional Consumers of Alberta (PICA)
Nancy J. McKenzie

Duke Energy Marketing (Duke)
Glenn MacIntyre

Alberta Federation of REAs Ltd. (REA)
K. L. Sisson, Q.C.
PART D: CUSTOMER CONTRIBUTION POLICY

Alberta Association of Municipal Districts and Counties (AAMDC)
   L. J. Burgess

EPCOR Utilities Inc. (EPCOR)
   J. M. Liteplo
   D. R. Wright, Q.C.

Canadian Forest Products Limited and Ainsworth Lumber Company Ltd. (Canadian Forest)
   Ted Vanderveen

Aboriginal Communities
   Jim Graves

Enron Canada Corporation (Enron)
   N. C. Herle

Amoco Energy Management Services Canada (Amoco)
   Norman Mills

Power Pool of Alberta
   Renee Usselman
1 INTRODUCTION

The Alberta Energy and Utilities Board (the Board or EUB) received an application dated May 18, 2000 from ESBI Alberta Ltd. (EAL, Transmission Administrator (TA) or the Applicant) respecting a general tariff application for the 2001 test year (the Application). The Application was made pursuant to Sections 27(1) and 49(2) of the Electric Utilities Act (EU Act) and requested approval of a revenue requirement for 2001 (the Phase I matters) and a rate design, including a revised customer contribution policy (the Phase II matters). EAL indicated that it would prefer receiving a decision on its proposed customer contribution policy on an expedited basis so as to assist potential demand customers contemplating investments in Alberta.

In Decision 2001-6, Part D of the matters dealt with to date by the Board pertaining to EAL's application, the Board rendered its findings with respect to EAL's proposed customer contribution policy. The Decision contained and number of directions and EAL was required to make a refiling. EAL submitted its refiling on March 22, 2001.

2 BOARD FINDINGS

In general, the Board is satisfied that EAL has complied with the directions contained in Decision 2001-6.

The only exception is the proposed Article 9.12 dealing with the discount rate to be used in certain circumstances. This is dealt with below.

The Board in 2001-6 addressed the situation of the contribution policy discount rate and determined that the following changes needed to be made:

- Revise the proposed Article 9.6 that would require customers to pay interest at the rate of 12% per year where a customer reduces its contract capacity before the completion of its commitment terms.
- Ensure that the charge to the customer offsets the costs that the TA is obligated to pay to the TFO to avoid leaving stranded costs with other customers.

1 Issued February 2, 2001
2 2001-6 pg. 68
3 2001-6 pg. 69
• Address the circumstance when no Board approved weighted average cost of capital was established.

Accordingly, the Board, in Decision 2001-6 directed EAL as follows:

The Board directs EAL in its refiling to change Article 9.6 that reflects EAL’s recommendation of an appropriate discount rate to calculate adjusted customer contributions in the event of revised commitment terms and/or revised revenue amounts. In so doing EAL should consider that it pays transmission facility tariffs to both investor owned utilities and municipally owned utilities. Tax effects may have to be considered. The Board also considers that whatever is approved by the Board may be subject to amendment in the future in order to harmonize EAL’s contribution policy with that of the DISCOs.

EAL responded with the following proposed method of determining an appropriate discount rate in a new article numbered Article 9.12:

9.12 The discount rate applicable to payments due under this Article shall be determined as follows:

(a) If the costs of capital are available for at least three regulated TFOs, including one municipally owned TFO, then the discount rate shall be the simple average of the costs of capital of all Alberta municipally owned and investor-owned TFOs for which the costs of capital are available; or
(b) If the conditions under (a) are not met, then the discount rate shall be equal to the yield on 30-year Government of Canada bonds plus 3.5 percent.

The Board is not persuaded that EAL has adequately considered the tax effects of investor-owned TFOs. The Board considers that 9.12 (a) above refers to regulated TFO rates of return which would be equivalent to after tax composite costs of capital and 9.12 (b) refers to an after tax current cost of equity.

Specifically the Board considers that the use of a before tax composite cost of capital would more accurately reflect the following:

• The cost of advancement under Article 9.2
• The calculation of levelized annual revenue under Article 9.4 (a) (iii)
• Credit arrangements under Article 9.5
• Recalculations of Customer contributions under Article 9.7

The Board recognizes that the use of a before tax composite cost of capital has deficiencies in that it does not explicitly recognize the method of depreciation that may be employed for tax purposes and can, therefore, result in the overstatement of annualized revenue requirements for properties that are depreciable.

---

4 Decision 2001-6 pg. 69
However, the Board considers that the use of a before tax composite cost of capital is sufficiently accurate for the above applications of the discount rate in Article 9 and produces more accurate results than an after-tax discount rate.

Although the Board recognizes that it would be efficient and simple to use a common discount rate regardless of whether the facilities are constructed by an investor owned utility or a municipally owned utility, the Board does not consider that a customer should have to pay a different (e.g. higher) payment than is necessary consistent with the Board findings described above.

The use of a single discount rate for situations related to on an investor owned and income tax paying utility would result in different (e.g. higher) end result payments than would be the case for a non-tax paying municipally owned utility.

The Board considers that a formula approach reflecting current market conditions, similar to EAL’s proposal in Article 9.12 (b), would be superior to attempting to reflect the embedded costs of capital for investor owned utilities or municipally owned utilities.

The Board considers that the following before tax discount rate formula would be appropriate:

\[ I_d = \text{current cost of debt; equal to the yield on 30-year Government of Canada bonds plus 1\% (the 1\% represents the spread between a TFO debt issue and a 30-year Government of Canada bond yield)} \]

\[ I_e = \text{current cost of equity; equal to the yield on 30-year Government of Canada bonds plus 3.5\% (the 3.5\% represents a typical risk premium for equity funds compared to risk free Canada bonds)} \]

\[ R_d = \text{debt ratio; equal to 65\%} \]

\[ R_e = \text{equity ratio; equal to 35\%} \]

\[ T = \text{combined federal and provincial income tax rate for investor owned TFOs} \]

\[ T = 0\% \text{ for municipally owned TFOs} \]

\[ GCB = \text{yield on 30-year Government of Canada bonds} \]

**For investor owned TFOs:**

The following discount rate was developed using \( T = 44\% \) as an example

\[ \text{Discount Rate} = R_d(I_d) + R_e(I_e)/(1 - T) \]

\[ = .65(GCB + 1\%) + .35(GCB + 3.5\%)/(1 - .44) \]

\[ = 1.275 \text{ GCB} + 2.8375\% \]

\[ = 1.28 \text{ GCB} + 2.8\% \text{ (Rounded)} \]
For municipally owned TFOs:

The following discount rate was developed using T=0

\[
\text{Discount Rate} = R_d(I_d) + R_c(I_c)/(1 - T)
\]

\[
= .65(\text{GCB} + 1\%) + .35(\text{GCB} + 3.5\%)/(1 - 0)
\]

\[
= \text{GCB} + 1.875\%
\]

\[
= \text{GCB} + 1.9\% \text{ (Rounded)}
\]

The Board notes that pursuant to Article 9.5, customer contributions must be paid prior to the TA initiating procurement of the required facilities.

With many projects going out to competitive bid, the Board further notes that it can no longer be assumed those transmission facilities within a municipal boundary would of necessity be constructed by a municipal TFO.

Accordingly, when transmission facilities are planned within the boundary of a municipality, but unassigned to a municipally owned TFO, the Board considers that the discount rate for investor owned TFOs should be used.

However, for situations where the transmission facilities have been supplied or clearly will be supplied by a municipally owned TFO then the municipally owned discount rate should be used. If a municipality were to become subject to income tax with respect to their transmission function, then the discount rate for investor owned TFOs should be used.

Accordingly, the Board directs EAL to delete subsections (a) and (b) and substitute the following wording for Article 9.12

9.12 The discount rate applicable to payments due under this Article shall be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the TA by an investor owned Transmission Facility Owner or for facilities supplied to the TA by an income tax paying municipally owned Transmission facility Owner:

\[
.65(\text{GCB} + 1\%) + .35(\text{GCB} + 3.5\%)/(1 - T) \text{ where GCB is equal to the yield on 30-year Government of Canada bonds and T is equal to combined federal and provincial income tax rate for investor owned TFOs}
\]

(b) For transmission facilities supplied to the TA by a non income tax paying municipally owned Transmission Facility Owners: the yield on 30-year Government of Canada bonds plus 1.9 percent

The Board expects that EAL will monitor any changes in the typical Board approved capital structure or cost of equity and will bring forward proposed changes, as necessary, to Article 9.12 in a future GTA.
The Board directs EAL, at the next GTA, to provide examples of the use of the investor owned TFO discount rate and the municipally owned TFO discount rate for each of the following calculations:

- The cost of advancement under Article 9.2
- The calculation of levelized annual revenue under Article 9.4 (a) (iii)
- Credit arrangements under Article 9.5
- Recalculations of Customer contributions under Article 9.7

For clarity, the Board does not require EAL to apply for approval of changes to the GCB yield or the T factor (the combined federal and provincial income tax rate for investor owned TFOs) in the Board approved formula.

3 REFILING NOT REQUIRED

The Board has attached a complete version of the Board approved Article 9. Since the Board revised section Article 9.12 is the only change to Article 9, it will not be necessary for EAL to refile a revised customer contribution policy for the T&Cs.

For the convenience of readers, EAL's submission on compliance with the directions of the Board in Decision 2001-16 is included as Appendix 2. Inclusion of this material does not necessarily mean that the Board is in agreement with the views of EAL.

4 BOARD ORDER

Therefore, having considered the Refiling of the Customer Contribution Policy, the Board hereby approves, as amended, EAL's Article 9 of its Terms and Conditions of Service, Customer Contribution Policy, to be effective January 1, 2001, and as attached hereto as Attachment 1.
Dated in Calgary, Alberta on April 3, 2001

ALBERTA ENERGY AND UTILITIES BOARD

<original signed by>

Neil W. MacDonald, P.Eng.
Presiding Member

<original signed by>

Arden J. Berg, P.Eng.
Member

<original signed by>

Member
APPENDIX 1

ARTICLE 9
(BOARD APPROVED)
CUSTOMER CONTRIBUTION POLICY

9.1 In considering requests to provide service to a new POC, or to increase the capacity of, or improve the service to an existing POC, the Transmission Administrator will determine the appropriate means of delivering the requested service.

(a) If the Transmission Administrator determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), or that the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the full cost of the transmission upgrade or extension (“the project”) shall be borne by the Customer.

(b) Otherwise, the Customer’s contribution to project costs shall be determined in accordance with Article 9.2 through 9.4.

9.2 Project costs will be classified as either system-related costs or Customer-related costs, as follows:

(a) The costs of that part of the project associated with Looped transmission extensions shall be classified as system-related costs, and shall be paid by the Transmission Administrator.

(b) The costs of that part of the project associated with Radial transmission extensions shall be classified as system-related if it is proposed in the transmission development plan (as that plan exists on the date the project is Commissioned) that the extension become Looped within five years. The Customer shall pay the cost of advancing that part of the project from the date established in the transmission development plan, which cost shall be calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.12.

(c) Where economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed initially, then the cost of that portion of the project deemed to be in excess of the Customer’s needs shall be classified as system-related. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer’s requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer’s requirements.

(d) All costs not identified under (a), (b), or (c) shall be classified as Customer-related costs. If the project is to serve a Customer not taking service under Rate DTS, then the Customer shall pay all Customer-related costs. Otherwise,
the Customer’s contribution to Customer-related costs shall be determined in accordance with Articles 9.3 and 9.4.

9.3 Customer-related costs will be classified as either supply-related costs or demand-related costs, as follows:

(a) The fraction of Customer-related costs classified as supply-related shall be STS/(STS+DTS), where STS and DTS are the STS and DTS Capacities, respectively, at the POC. All supply-related costs shall be paid by the Customer.

(b) The Customer-related costs not classified as supply-related costs shall be classified as demand-related costs. The Customer’s contribution to demand-related costs shall be in accordance with Article 9.4.

9.4 The Customer’s contribution to the demand-related costs shall be calculated as follows:

(a) 

Customer contribution = demand-related costs - roll-in ceiling, where:

(i) roll-in ceiling = commitment term amount + revenue-related amount;
(ii) commitment term amount = $400,000 for every one-year commitment term after the first five-year commitment term. A commitment term is a period within which the Customer commits to maintain its Contract Capacity at or above its initial Contract Capacity. The maximum commitment term amount is $6 million.
(iii) revenue-related amount = three times the levelized annual revenue from the new or expanded service, where the levelized revenue is determined based on the projected Contract Capacities that are contracted at the time of the calculation of the Customer contribution. The discount rate to be used in the calculation of the levelized annual revenue shall be that established under Article 9.12.

(b) If the calculation in (a) results in a negative Customer contribution, no Customer contribution is payable. The Transmission Administrator will make no payment to the Customer with respect to any excess of the roll-in ceiling over the demand-related costs.

9.5 Any Customer contribution to be paid to the Transmission Administrator must be paid prior to the Transmission Administrator initiating procurement of the required facilities, unless other credit arrangements acceptable to the Transmission Administrator are made. The discount rate to be used in any credit arrangement shall be that established under Article 9.12.

9.6 The cost estimate used in the calculation of project costs will be based on certain assumptions, including but not limited to assumptions about the method of construction, the routing of facilities, and the approvals and rights of way required to
serve the Customer in accordance with the Customer's requests. In the sole opinion of the Transmission Administrator, where a request for service is changed by a Customer or any assumptions are changed for reasons beyond the reasonable control of the Transmission Administrator or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) Subject to (b), where there is an increase in the Customer contribution, this amount is immediately payable to the Transmission Administrator, or

(b) If feasible, the Customer and the Transmission Administrator may modify the terms of the contract to adjust the Contract Capacity or the number of commitment terms.

(c) The Customer shall have the right to cancel the request for service by paying to the Transmission Administrator, and/or the TFO, all costs then incurred or required to be incurred to discharge the Transmission Administrator, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.7 Certain material events may result in a recalculation of the Customer contribution in respect of a project. Any recalculation shall make use of revised commitment terms, revenue-related amounts, and other available information, and may result in payments by the Transmission Administrator to the Customer or by the Customer to the Transmission Administrator. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) A Customer materially increases or decreases its Contract Capacity or number of commitment terms prior to the expiration of its original commitment terms;

(b) The actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;

(c) A facility that had been classified as system-related under Article 9.2(c) is reclassified as Customer-related due to load growth or the addition of a new POC.

(d) A material error is detected in the original calculation.

(e) A difference between the estimated costs of the project and the actual costs of the project.

9.8 If the Transmission Administrator installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the Transmission Administrator will adjust the original Customer's contribution and assess each of the new Customers a contribution, as follows:

(a) The contributions of the existing Customer and the new Customers will be determined on the basis of:
(i) the commitment terms of the original and new Customers;
(ii) the revenue-related amounts of the original and new Customers;
(iii) the Contract Capacities of the original and new Customers;
(iv) the extent of shared facilities; and
(v) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(v) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11, any project whose remaining adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, and no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the Transmission Administrator subsequently deems that all or part of an original Customer's facilities have become system-related.

9.9 Where relocation of transmission facilities is required, the Transmission Administrator will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

9.10 Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the Transmission Administrator and the party responsible for costs in the other Control Area.

9.11 The Transmission Administrator reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the Transmission Administrator may:

(a) Limit the maximum number of commitment terms used to determine the roll-in ceiling.
(b) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as customer-related.
(c) Determine that a refund of a Customer contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.
(d) Determine that a refund of a Customer contribution must be returned to the Transmission Administrator where it is demonstrated that an error was made or that an inappropriate refund was given.
9.12 The discount rate applicable to payments due under this Article shall be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the TA by an investor owned Transmission Facility Owner or for facilities supplied to the TA by an income tax paying municipally owned Transmission facility Owner:

\[0.65(GCB + 1\%) + 0.35(GCB + 3.5\%)/(1 - T)\]

where GCB is equal to the yield on 30-year Government of Canada bonds and T is equal to combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the TA by a non income tax paying municipally owned Transmission Facility Owners:

the yield on 30-year Government of Canada bonds plus 1.9 percent.
APPENDIX 2

ESBI Alberta Ltd.
Response to Board Directions in Decision 2001-6
March 22, 2001

The following sets out the Transmission Administrator’s responses to the Board’s directives in Decision 2001-6\(^5\) concerning the customer contribution policy. The responses are followed by a table that sets out the correspondence between Article 9 of the Terms and Conditions as submitted in EAL’s July 20, 2000 refiling and as modified in response to the Board’s directives.

1. *The Board considers that it would be helpful to include a definition of both “Radial” and “Looped” facilities in the T&C and the Board directs EAL to include such definitions in its refiling.* [Page 62]

Definitions of “radial” and “looped” have been included in Article 1 of the T&C. Pictorial examples of radial and looped extensions are given in Diagram #1.

2. *In view of the growing experience with the new policy and its interaction with the DISCO’s contribution policy, the Board directs EAL to address any needed changes to the contribution policy at the next GTA.* [Page 64]

EAL will comply with this directive at the next GTA.

3. *Further, the Board directs EAL, before the next GTA, to prepare and make public brochures or guidance material to assist potential customers in understanding its contribution policy. The Board assumes that EAL will naturally file copies with the Board and parties for information.* [Page 63]

EAL will prepare and make public the brochures and guidance material before the next GTA, and will file these materials with the Board for information.

4. *Further, given the increased clarity provided by the examples examined in the Hearing, the Board directs EAL, in its refiling, to include appropriate examples, that include both narrative and diagrams, of the application of the contribution policy.* [Page 64]

Examples of the operation of the contribution policy are currently being prepared, and will be filed with the Board as soon as practicable. As experience is gained with the operation of the policy, further examples will be added to the document.

Diagram #1
Examples of Radial and Looped Extensions

Starting Point: There is one "visible" electrical path between POC1 and POC2, plus some number of paths within the rest of the system.

The extension to POC3 is radial (in this case a "double radial") because the number of paths between POC1 and POC2 has not changed. There is still only one visible path, and the number of paths within the rest of the system has not changed.

The extension to POC4 is looped because it creates an additional path between at least two POCs other than POC4 (for example, from POC1 to POC3, as shown). The extension to POC5 is radial because it does not create an additional path between any two POCs excluding POC5.
5. The Board agrees with EAL and the Board directs EAL in its refiling to amend Article 9.2 to make explicit reference to the 5-year planning horizon. In its refiling, EAL should clarify that the refund would follow normal refund policy. [Page 64]

The 5-year planning horizon has been explicitly referenced in Article 9.2(b). As stated in that article, a transmission extension will be classified as system-related if the Transmission Development Plan in effect as of the commissioning date shows that the facility will be looped within five years. Article 9.8 provides for a later adjustment to the contribution if some or all of the facilities are reclassified as system-related within 20 years.

6. In order to have empirical data, the Board directs EAL to provide at the next GTA, for each of the years 1998, 1999, and 2000, the following information for those multiple customer PODs that would have required a transmission contribution using the proposed contribution policy... [Page 65]

EAL will comply with this directive at the next GTA.

7. The Board directs EAL to provide the above same information, at the next GTA, on an actual basis for each month in 2001 during which the new TA contribution policy was in place. [Page 65]

EAL will comply with this directive at the next GTA.

8. Accordingly, the Board directs EAL to use the DTS/(STS+DTS) and the corresponding STS/(STS+DTS) formula to determine the demand customer-related costs and the supply customer-related costs for transmission facilities prior to applying the contribution policy. [Page 66]

These ratios are used to classify costs as either demand-related costs or supply-related costs, as set out in Article 9.3.

9. Accordingly, the Board directs EAL, in its refiling, to reflect, in its contribution policy, the proposal to “systemize” connection costs when dual usage occurs. [Page 66]

Article 9.11(b) allows the Transmission Administrator to exercise its discretion and “systemize” costs that might otherwise be considered customer-related when circumstances warrant. An example of a potential application of this article—that being a line to Jasper—was cited by the Board in its Decision.⁶

⁶Decision 2001-6, p. 62.
10. Accordingly, the Board directs EAL, in its resiling, to revise its refund policy to achieve the following:
   - The contribution should be eligible for full refund for the first five years as proposed by EAL.
   - For the remaining 15 years the contribution would be amortized on a straight-line basis with the remaining book value of the contribution being available for refund to the customer.
   - Commencing in year 11, any project whose remaining balance is below $50,000 can be truncated for refund purposes and no further refunds would be due. [Page 68]

Article 9.8, in particular paragraphs (b) and (c), gives effect to this directive.

11. Further, the Board directs EAL, in the next GTA, to address any change in the recommended project cost threshold for refunds beyond the 10 year period or any administrative cost levy to compensate for the extra administrative cost involved. The Board accepts TCE’s argument that customers would be willing to pay for any incremental administrative costs. Accordingly, at the time this issue is addressed, the Board will consider whether the effective date for the requirement for customers to pay the additional administrative costs should be the effective date of the new contribution policy. [Page 68]

EAL will address this directive in the next GTA.

12. Accordingly, the Board directs EAL, in its resiling, to ensure an appropriate clause exists to provide EAL with the discretion to determine that a refund in a specific situation may not be given or that a refund may be deferred pending specified circumstances. A specified circumstance could include, for example, the lack of a demonstrated sustained operation of a new or unproven industrial plant. This clause should address the situation where a customer was denied a contribution refund under EAL’s discretionary authority but subsequently satisfactorily completed some specified probationary period. After satisfactorily meeting the criteria, the customer should be then eligible for an interim or complete refund. [Page 68]

This directive has been incorporated as Article 9.11(c).

13. Further, the Board directs EAL, in its resiling, to include a clause that provides for the ability of the TA to have a refund returned to the TA where it was demonstrated that an error or inappropriate refund was given. [Page 68]

Article 9.11(d) gives effect to this directive.
14. The Board directs EAL in its refiling to incorporate changes that reflect a reciprocal arrangement in the event of revised commitment terms and/or revised revenue amounts. [Page 68]

The reciprocity is reflected in Article 9.7, which provides for a recalculation of the customer's contribution based on several criteria, including revised commitment terms and/or revised revenue amounts. The payments under Article 9.7 can flow from the Transmission Administrator to the Customer or vice versa.

15. The Board directs EAL in its refiling to change Article 9.6 that reflects EAL's recommendation of an appropriate discount rate to calculate adjusted customer contributions in the event of revised commitment terms and/or revised revenue amounts. In so doing EAL should consider that it pays transmission facility tariffs to both investor owned utilities and municipally owned utilities. Tax effects may have to be considered. The Board also considers that whatever is approved by the Board may be subject to amendment in the future in order to harmonize EAL's contribution policy with that of the DISCOs. [Page 69]

The discount rate for all payments under Article 9, including adjusted customer contributions arising from revised commitment terms and/or revised revenue amounts, is established in accordance with Article 9.12. That article provides for the use of the costs of capital of both municipally owned and investor-owned utilities when those costs are available.

16. Further, the Board directs EAL to include clauses to address the situation where a cost of capital is not available due to a negotiated settlement. [Page 69]

Article 9.12 specifies that, where the appropriate costs of capital are not available, a risk-free rate equal to 30-year Government of Canada bonds, plus a risk premium of 3.5%, will be used for the discount rate. The figure of 3.5% was set in Decision U990997 and in TransAlta Utilities Corporation's 2001 negotiated settlement.8

17. Accordingly, the Board directs EAL, in its refiling, to change the Roll-in Ceiling policy to incorporate interpolations between the 5-year commitment terms to reflect the recommendation of TCE with respect to pricing cliffs. [Page 70]

The interpolations between the five-year commitment terms have been realized by changing the commitment term amount from $2 million for each five-year term to $400,000 for each one-year term.

18. Similarly, the Board directs EAL, in its refiling, to revise the revenue-related portion of the Roll-in Ceiling to be based on the levelized annual revenue from a new service

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over the qualifying commitment terms, as long as the future increases in contract capacity are contracted at the time of the original commitment. [Page 70]

The necessary changes have been incorporated in Article 9.4(a)(iii).

19. Accordingly, the Board directs EAL, in its filing, to include revised wording in the Terms and Conditions that provides for the necessary authority for EAL to deviate from the established contribution policy. [Page 71]

Article 9.11 provided the Transmission Administrator with the ability to exercise its discretion, acting reasonably, in the application of the customer contribution policy.

20. Accordingly, the Board directs EAL, in its filing, to amend the contribution policy to clarify that EAL has the discretion to limit the contractual term in order to mitigate the risk associated with serving new demand customers. [Page 73]

Article 9.11(a) gives the Transmission Administrator the authority to limit the maximum number of commitment terms used to determine the roll-in ceiling.

21. Accordingly, the Board directs EAL, at the next GTA, to address the proposal to amend Article 10 to provide the TA with discretion over what forms of security it will accept to mitigate the risk that a customer might abandon service and create the potential for stranded costs. [Page 73]

EAL will comply with this directive at the time of the next GTA.

22. However, the Board directs EAL to develop, with the TFOs and with customers, a set of reliability objectives for the transmission system, the means for measuring them and the means for identifying which customers at which locations are most affected by reliability that does not meet objectives for consideration at the time of the 2003 GTA. These reliability objectives should be incorporated into the system of objectives that EAL sets for itself for 2003 GTA Phase I purposes. These objectives should include the following:
   ▪ readily measurable, i.e. the data must be available at reasonable cost
   ▪ the objective must be set at a reasonable cost to reliability tradeoff point
   ▪ the means, if any, by which affected customers are identified and located. [Page 76]

EAL will comply with this directive at the time of the 2003 GTA.
23. With the restructuring of the electric industry, the responsibility for reliability is now dispersed among several players. The Board directs EAL and stakeholders to define responsibility for reliability objectives between the TA and TFOs, when developing objectives for the transmission system. [Page 76]

EAL will comply with this directive at the time of the 2003 GTA, in conjunction with the previous directive.

24. The Board directs EAL, in its refiling, to incorporate the following into its contribution policy:
   - The method of assessing customer contributions in situations where economics or system planning dictate that a larger facility is to be initially installed, and the additional cost of the 'customer' facility is treated as 'system' until such time as growth or a second POD is required to be served.
   - The method of assessing customer contributions where the original load used to determine the contribution for the first customer POD was too low and the actual load served would have required a different contribution.
   - The method of assessing customer contributions where it is appropriate to take into account the total load, future considerations for growth and the entire facility at the POD. [Page 79]

The directive in the first bullet has been incorporated into Article 9.2(c). The second directive has been complied with by establishing for the Transmission Administrator the ability to re-assess customer contributions based on a variance between assumed and actual contribution determinants, as set out in Article 9.7. Article 9.2(c) addresses the third bullet by providing for costs above the Customer's requirements to be classified as system costs until such time as other customers require system access using the facilities in question.

25. The Board directs EAL, in its refiling, to set out the method of assessing customer contribution in situations where it is appropriate for the cost of advancement to represent customer related costs rather than the full project costs. [Page 80]

Article 9.2(b) provides for the customer to pay only the advancement costs for facilities that are identified in the Transmission Development Plan.

26. Accordingly, the Board directs EAL, in its refiling, to revise its T&Cs to commence the start of the 5-year refund clock at the time the facilities are put into service or are available for service. [Page 81]

The facility commissioning date, as defined in Article 1, is used throughout Article 9 as the reference point for date calculations.
27. Further, the Board directs EAL, in its refiling, to submit the terms of the payment schedule for a customer contribution. [Page 81]

Article 9.5 states that the customer contribution must be paid to the Transmission Administrator prior to initiating procurement of the facilities. That Article also allows for alternative financial arrangements acceptable to the Transmission Administrator, and associates with any payment stream a discount rate as set out in Article 9.12. This arrangement will be revisited at the time of the next GTA, in compliance with Directive 28.

28. The Board considers that the handling of contributions prior to the time the facilities are put into service is worthy of further examination at the next GTA and therefore, the Board directs EAL, at the next GTA, to submit revised practices for these circumstances. [Page 81]

EAL will comply with this directive at the time of the next GTA.

29. The Board directs EAL to provide to the Board a proposed schedule for the refiling, including implementation of the approved contribution policy, within one week of the issue of this Decision. [Page 82]

Complete.
Table 1: A Guide to the Original Article 9

<table>
<thead>
<tr>
<th>Original Article</th>
<th>Revised Article(s)</th>
<th>Summary of Changes</th>
</tr>
</thead>
<tbody>
<tr>
<td>9.1</td>
<td>9.1, 9.2</td>
<td>The last sentence of the original 9.1 has essentially been incorporated into 9.2.</td>
</tr>
<tr>
<td>9.2</td>
<td>9.2</td>
<td>The first sentence of the original 9.2 is now embodied in 9.2(a) and 9.2(b). The last sentence is reflected in 9.2(d). Article 9.2(c) is a new construct reflecting part of Directive 24.</td>
</tr>
<tr>
<td>9.3</td>
<td>9.4</td>
<td>The commitment term amount has been changed from $2M for each five-year term to $400k/year in response to Directive 17. The revenue-related amount is now based on the levelized annual revenue in response to Directive 18.</td>
</tr>
<tr>
<td>9.4</td>
<td>9.1(a)</td>
<td>The wording has been revised to state that the Customer shall pay the full cost of the Project (the original stated that the roll-in ceiling would be zero). The effect is the same.</td>
</tr>
<tr>
<td>9.5</td>
<td>9.2(d)</td>
<td>The wording has been changed in the same manner it was for the original Article 9.5.</td>
</tr>
<tr>
<td>9.6</td>
<td>9.7</td>
<td>The circumstances under which recalculation of the Customer contribution can occur have been broadened in response to several Board directives.</td>
</tr>
<tr>
<td>9.7</td>
<td>9.5</td>
<td>Reference to the discount rate to be used with any credit arrangement has been added.</td>
</tr>
<tr>
<td>9.8</td>
<td>9.6</td>
<td>Minor edits.</td>
</tr>
<tr>
<td>9.9</td>
<td>9.6(c)</td>
<td>Minor edits.</td>
</tr>
<tr>
<td>9.10</td>
<td>9.8</td>
<td>The time within which refunds are available has been extended to 20 years from 10, and the amortization has been modified accordingly, both in response to Directive 10.</td>
</tr>
<tr>
<td>9.11</td>
<td>9.9</td>
<td>No change.</td>
</tr>
<tr>
<td>9.12</td>
<td>9.10</td>
<td>Minor edits.</td>
</tr>
</tbody>
</table>
Alberta Electric System Operator (AESO)

2005/2006 General Tariff Application

August 28, 2005
Rider E would address only the calibration factor related to transmission system losses and would apply to Rate STS as well as all opportunity rates (DOS 7 Minutes, DOS Term, EOS, and IOS).

Rider E’s purpose would be “…to adjust loss factors to ensure that the actual cost of losses is reasonably recovered through charges and credits on an annual basis” in accordance with Subsection 21(1) of the Transmission Regulation.

Rider E would be determined prior to the beginning of each calendar quarter, and would be set at a level that, if applied for the remainder of the calendar year, would result in the full recovery of the actual cost of transmission line losses by the end of the calendar year.

Rider E would be applied as a calibration factor percentage based on the preceding which would be added to or subtracted from all location-specific loss factors for generators and all opportunity services.

Rider E would apply on a prospective basis only in accordance with Subsection 21(2) of the Transmission Regulation. However, an annual reconciliation would be filed with the EUB for information purposes only.

As Rider E will be set in advance based on a forecast year-end balance, there will likely remain some small difference between the anticipated and actual cost of transmission line losses at the end of the year. Any year-end balance will be included in the next year’s Rider E in accordance with Subsection 21(2) of the Transmission Regulation.

Rider E should primarily address variances from forecast of losses volumes. Variances from forecast of pool price should not require Rider E recovery or refund as both the cost of transmission system losses and the recovery (through a percentage of pool price) varies directly with pool price. Establishing Rider E with a purpose of achieving a zero balance at year-end should avoid any seasonal variations that could arise if the rider’s purpose was to achieve a zero balance at the end of the following quarter.

In reply, the AESO noted that no party had commented upon this Rider proposal and suggested it should be approved as filed. The Board agrees and it is approved as filed.

6 TERMS AND CONDITIONS – CONTRIBUTION POLICY

6.1 Customer Contribution Policy

The AESO proposed a number of major revisions to the customer contribution policy in the 2005-2006 Application.

6.1.1 High Level Policy Principles

The AESO submitted in the Application that the current contribution policy approved in Decision 2001-6 was devised with regard to four major principles, namely:

- The desire to impose an economic siting discipline on customers;
- Consistency with the “postage stamp” principle;
- Harmonization with the contribution policies of distribution facility owners (Discos); and
- Consistent application of the policy to all load customers.
The AESO submitted that the refinements to the contribution policy proposed in the Application were necessary to achieve these principles and to reduce the need for discretionary classification of project costs.

The Board will evaluate the AESO’s proposed changes to the contribution policy in light of these policy principles in the sections that follow. In addition, the Board will also consider other factors in assessing the appropriateness of the AESO’s proposal that have arisen since Decision 2001-6 was released. In particular, the Board will be mindful of the impact that the Transmission Regulation may have on these principles.

**Provision of Economic Signal(s)**

The Board notes that Decision 2002-082, in respect of ATCO Electric’s (AE’s) 2002 Investment and Contribution Policy, extensively investigated the principles underlying electric utility contribution/investment policies. In turn, that Decision quoted Decision 2000-1 as follows in order to set out certain basic principles for its disposition of the AE contribution policy:

> The Board considers that customer contributions are suitable in circumstances where service to a customer may impose costs on other customers for which they should not be responsible. An appropriate contribution policy therefore provides a suitable balance to an unlimited obligation to serve by imposing economic discipline on siting decisions. It transfers the economic burden of connection of new customers from the utility and its existing customers to the new customer. In other words, it exerts some of the discipline of the utility’s economics on the economic decision-making of the customer. The Board considers that customer contributions should relate only to the local connection costs of the system expansion. The deep system costs of expansion are properly the responsibility of all customers, form part of the utility’s revenue requirement and should be recovered from all customers through rates.

The Board’s views on the underlying purpose of a contribution policy have not changed since Decision 2002-082 was issued. As such, it remains important to the Board that the AESO’s contribution policy should continue to exert an economic discipline on siting decisions by sending price signals reflective of the AESO’s economics to an interconnecting customer.

The Board also notes the following finding reflected in Decision 2002-082 (originally derived from Decision 2001-38):

> The Board considers that these same observations apply at the distribution level in the case of AE’s investment policy. Achieving a suitable balance to an unlimited obligation to service does not necessarily mean that investment levels should be set as high as possible without placing undue upward pressure on rates. For example, if a technological breakthrough significantly reduced the cost of connecting new customers, it may be appropriate to reduce the level of investment to maintain intergenerational equity. In such circumstances, all generations of customers would benefit from investment toward the same functionality of service, and all customers would benefit from the eventual downward pressure on rates.

> Conversely, if the Board were persuaded that it was appropriate to adopt a new standard of construction (for example, underground instead of overhead construction), the Board might approve a significant increase in the level of investment, which would eventually result in upward pressure on rates for all customers.
The Board considers that the appropriate maximum level of investment could be affected by factors such as technological advancements and changes in standards of construction. Absent such factors, the Board would generally expect that maintaining a suitable balance to an unlimited obligation to serve would result in investment levels increasing with inflationary pressures, offset by productivity and technological improvements. This would result in different generations of customers benefiting from investment toward the same functionality of service, and would also result in approximately the same economic discipline on different generations of customers.

The Board notes that, while the above noted passage was taken from a decision issued by the Board in respect of ATCO Electric’s contribution investment policy, the principles described therein also apply to the AESO. Accordingly, the Board considers that three aspects of the above noted passage are relevant in considering the disposition of the AESO’s proposed contribution policy. These aspects are:

- Establishing a maximum investment allowance;
- Establishing standards for functionality and service characteristics; and
- Recognizing the changing nature of the standards for functionality and service.

The Board notes that the above referenced passage does not support a proposition that investment allowances should be set at the maximum amount of incremental revenues generated by the interconnection of a new customer. Rather, the Board has identified its concern that such a proposal may place undue upward pressure on rates. The Board continues to be concerned that setting investment allowances at a level significantly above the expected cost of an interconnection would be inflationary. In particular, the Board is concerned that an excessive investment allowance could provide incentives for customers to pursue higher standards of connection facilities than required, largely on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance. Accordingly, the Board considers that the incremental revenue generated by an interconnection should only be used as an upper bound but should not be the primary driver of the investment formula. The Board will provide further elaboration on these matters in its discussion of the AESO’s proposed Maximum Investment formula, found in Section 6.1.4 of this Decision.

The Board also notes that the passage above from Decision 2002-082 focuses on consideration of the functionality and service characteristics provided by the interconnection facilities rather than on the financial aspects as the principal driver of the contribution policy. Given this focus, investment allowances should be set with regard to the anticipated cost of establishing an interconnection to the AIES (Alberta Interconnected Electrical System) reflecting acceptable standards of functionality/service established by the AESO.

The above referenced passage from Decision 2002-082 also recognizes that the standards of functionality and service characteristics may change over time. The Board discusses this issue further in Section 6.1.3.1 of the Decision respecting the AESO’s proposed definition of “AESO Standard Service”.

Consistency with Postage Stamp Principle

The AESO suggested in the Application that certain aspects of its proposed contribution policy would bring the policy in closer alignment with the “postage stamp principle” outlined in Section 30(3) of the EUA which reads as follows:
s. 30 (3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

The Board notes that the wording of Subsection 30(3) substantially preserves the postage stamp rates provision from Section 27 of the version of the EUA in effect prior to June 2003, which was worded as follows:

s. 27(2) The rates set out in the tariff

(a) must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Transmission Administrator, and

(b) must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system.

(3) Rates are not unjust or unreasonable simply because they are prepared taking into account subsection (2)(b).

The Board notes that previous Board Decisions in respect of the AESO’s predecessor, EAL, including Decision 2000-1 and Decision 2001-6 examined the manner in which the postage stamp principle should coexist with the use of contribution policies to provide appropriate economic siting signals. In particular, the Board determined in Decision 2001-6 that because the contribution policy proposed by EAL did not have the effect of making the location of an electric distribution system on the transmission system or the geographic location of a POD within Alberta a consideration in how the contribution policy was applied, the contribution policy of EAL complied with the postage stamp requirements of Subsection 27(2)(b). Accordingly, the Board considers that the contribution policy of the AESO’s existing tariff may also be judged to align with the postage stamp principle as described in Subsection 30(3). It did not need to be altered to be brought into compliance.

**Harmonization of the AESO Contribution Policy with Contribution Policies of Discos**

The AESO advised that it is seeking to harmonize its contribution policy with those of the other regulated distribution companies in Alberta. The AESO submitted that the form of the maximum local investment function proposed in the Application would provide a better harmonization with the similarly-structured load-based investment policies of most distribution facility owners (Discos). By using an average unit investment allowance that varies with contract term, the maximum local investment allows customers to lower the customer contribution required by contracting for a longer DTS contract term.
The AESO indicated that it hoped its redesign of the maximum investment formula would ensure that approximately 80% of customer interconnection projects would be fully covered by the selected maximum investment limit while 20% of projects would only be partially covered. The AESO noted this “80/20 criteria” was initially adopted in order to preserve intergenerational equity relative to the customer contributions required during the vertically integrated regime that existed prior to the unbundling of the Alberta electricity system that occurred in 2001. The AESO noted that the “80/20 criteria” was accepted by the Board in Decision 2001-6.69

The Board notes that the rationale for seeking to harmonize the contribution policies of the AESO with the Discos was evaluated by the Board in Decision 2001-6. As noted in Decision 2001-6, the harmonization issues under consideration in that proceeding primarily related to the following aspects of the contribution policy:

- Ensuring the appropriate harmonization between the contribution policies of the distribution utilities and the AESO’s predecessor;
- Ensuring that the contribution policy did not disturb proper planning; and
- Understanding how the customer contribution policy affects a customer’s decision to choose to become a “direct” transmission-connected customer versus a distribution-connected or isolated generation customer.

The Board considers that while progress has been made in relation to the last of the harmonization goals noted above, additional improvements could be made. In particular, and as further discussed in Section 6.3.2 of this Decision, the Board considers that the primary focus on Disco/AESO harmonization efforts should be directed towards harmonizing the definitions of “standard facilities” and “optional facilities”.

Application of Supply Contribution Principles to Load Contribution Policy
The Board notes that the load customer contribution policy proposed in the Application parallels several aspects of the contribution policy for new interconnecting generators as outlined in the Transmission Regulation. The major components of the generator contribution policy are described in Sections 16 and 17 of the Transmission Regulation.

Through information requests, the Board sought to clarify the extent to which consistency is required between aspects of the Transmission Regulation’s generator contribution policy and the load contribution policy proposed by the AESO for the Application. The Board notes that, in one of its responses70, the AESO indicated that Subsection 16(4) of the Transmission Regulation had played some part in the formulation of the load policy, namely, the determination of whether a cost arising from an interconnection should be designated as a “system” or a “customer” cost.

The AESO noted that whereas Subsections 16(1), 16(2), and 16(3) all refer specifically to the interconnection by the “owner of a generating unit” to the transmission system, Subsection 16(4) of the Transmission Regulation uses the terminology “another person”. The AESO thus considered that the use of “another person” rather than “owner of a generating unit” was intended to imply general application of Subsection 16(4) to both generators and loads.

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69 Decision 2001-6, page 70
70 BR-AESO-017
The AESO further noted that, in general, facilities constructed for the same purpose should be classified the same regardless of whether the interconnection is for a generator or a load customer. In the AESO’s view, to do otherwise would be problematic for dual-use interconnections (serving both a generator and a load customer). The AESO did not consider that any other aspects of the *Transmission Regulation* had influenced its proposed contribution policy for load customers.\(^{71}\)

The Board has considered the provisions in Section 16 of the *Transmission Regulation* and agrees with the AESO that the reference to “another person” rather than “the owner of a generating unit” in Subsection 16(4) of the *Transmission Regulation* may be interpreted as a reflection of the Government’s intent to apply this provision to any type of customer that wishes to make use of previously constructed interconnection facilities and is not intended to be restricted to generators alone. However, as noted by the AESO, the more specific references to “a generating unit” in the other subsections of Sections 16 and 17 of the *Transmission Regulation* have the effect of making these requirements mandatory only in respect of interconnecting generating units. Therefore, while the Board is not precluded from adopting the AESO’s proposal to devise a load customer contribution policy that largely parallels the design principles for generator contributions outlined in the *Transmission Regulation*, the *Transmission Regulation* does not require the AESO to devise a parallel load customer contribution policy. Whether it is in the public interest to do so is a separate issue that must be determined by the Board.

The Board considers that the fundamental difference between the load customer contribution in the AESO’s current tariff and the generator contribution policy relates to the manner in which “system-related” and “customer-related” costs are determined. The existing contribution policy is essentially top-down in nature in the sense that the baseline for the identification of system-related and customer-related costs arises from an evaluation of the facilities currently available or contemplated for addition over the next five years in relation to the AESO’s long term system plan. Under this approach, any additional facilities and costs arising from a new customer’s interconnection are identified as customer-related costs and are charged to the existing customer. In contrast, the generator contribution policy described in the *Transmission Regulation* may be considered more of a bottom-up approach, in the sense that the generator’s local interconnection facility costs are determined first and deemed to be the customer-related costs associated with the interconnection. Any further residual incremental system enhancement or upgrade costs not fitting the definition of a local interconnection facility cost are deemed to be system-related, and thus excluded from the contribution policy.

As further described in the Board’s discussion of the designation of system and customer costs in Section 6.1.2 of this Decision, the Board does not, in general, consider that the generator contribution policy principles outlined in the *Transmission Regulation* should necessarily be used as the model for establishing the load customer contribution policy unless doing so is supportable under generally accepted principles of rate design.

### 6.1.2 Designation of System-Related Costs

The Board notes that the first step in the application of any contribution/investment policy is to classify costs as either system-related or customer-related.

\(^{71}\) BR-AESO-017
The mechanism to classify costs as system-related or customer-related was set out in Article 9.2 of the existing AESO Tariff’s Terms and Conditions. Article 9.2 reflects the framework established by the Board in Decision 2001-6.

Under Article 9.2, the determination of whether a proposed interconnection project would be classified as system-related or customer-related depended on whether the proposed project was radial to the existing transmission system. If a proposed interconnection was radial, new interconnection facility costs were generally designated as customer costs. Alternatively, if all or a portion of a new interconnection project completed a looped configuration in conjunction either with existing transmission system facilities or in conjunction with system upgrades expected to be built within the next 5 years, the looped portion of a new interconnection project was deemed to be a system-related cost. Article 9.2 also allowed for the customer to pay for the cost of advancing any portions to be looped within the subsequent 5 year period.

Article 9.3 of the proposed T&Cs in the Application establishes the proposed methodology to designate system and customer-related costs. Although the AESO proposes to preserve the looped vs radial criteria it had established in Article 9.2 of the existing T&Cs, the looped vs radial designation will no longer be the primary determinant of whether a cost was to be designated as system or customer-related. In its place, the AESO has proposed the additional Article 9.3(a), which concentrates on defining the specific types of facilities within a new radial interconnection project that the AESO considers to be customer-related. In conjunction with its proposed focus on typical local interconnection facilities as the basis for identifying customer-related costs, the AESO has also proposed to designate any enhancements to the existing transmission system that may arise as a result of a new customer interconnection to be, by definition, system-related for the purposes of the contribution policy.

The AESO contends that its revised criteria for designating system-related and customer-related costs are necessary because the existing process for designating costs may tend to be unpredictable for customers. In particular, the AESO noted that because the AESO exercises some discretion in the case of enhancements, such as protection upgrades, it is possible under the existing T&Cs to designate such costs as either system or customer costs, depending on the AESO’s determination as to who benefits from the interconnection upgrade.  

The AESO provided a conceptual illustration of three basic approaches to the classification of system and customer costs in Figure 6.1.1 of the Application. The AESO noted that, while each scenario always classifies local connection costs as customer-related and classifies bulk system costs as system-related, the classification of system enhancements varied between the three alternatives. Of the three alternatives described by Figure 6.1.1, the AESO chose “Alternative 1” (all system enhancements designated as system costs) on the basis that the chosen alternative would provide a high level of predictability and would provide consistency in the treatment of load and generator interconnection projects.

The AESO’s proposal to treat system enhancements as system costs for the purposes of the contribution policy was supported by ATCO Electric. Conversely, FIRM opposed the automatic designation of enhancements as system costs.
While desirable, the Board does not consider the goal of trying to achieve greater consistency between the generator and load customer contribution policies to be the most important public interest consideration. Accordingly, the Board is not persuaded that consistency with the generator contribution policy should, in and of itself, lead the Board to endorse the AESO’s proposed Alternative 1 in which all costs not specifically identifiable as a local interconnection cost should be deemed as system cost for contribution policy purposes.

The Board has difficulty accepting the proposition that decision making as to whether a system enhancement should be designated as a system or a customer cost should be problematic for the AESO. The Board notes that the radial vs looped framework currently in place in the T&Cs was proposed in part because it provided enhanced objectivity and predictability from a customer perspective.74

The Board also notes that the AESO has an explicit obligation under Subsection 4(2) of the Transmission Regulation to identify all transmission facility projects which the AESO proposes to initiate through a needs application within 5 years from the release of each update of its long term transmission system plan. Additionally, in respect of each project so identified, the AESO is required to provide the anticipated implementation schedule for the project. The Board considers that since detailed information must now be provided as required in Subsection 4(2), the AESO should be able to objectively assess whether a cost arising from a new interconnection warrants system or customer cost treatment.

With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.

The Board does not wish to take away the AESO’s discretion under Article 9.11 of its proposed T&Cs to deem costs normally designated as customer costs to be system-related costs in appropriate circumstances. The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the Transmission Regulation.

6.1.3 “Standard” and “Optional” Interconnection Facilities

6.1.3.1 AESO Standard Service Definition

The T&Cs submitted with the Application include a proposed definition of the facilities that the AESO considers to be the standard facilities that it expects to provide for a new interconnection project. The definition of AESO Standard Facilities from Article 1 of the proposed T&Cs is as follows:

“AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection.

74 Decision 2001-6, p. 3 and p. 62
The AESO noted in its Argument that the inclusion of a definition of standard facilities in the Tariff was intended to provide clarity and transparency to a long-standing practice.75

A number of parties addressed the definition of standard facilities in argument, including ATCO Electric, TCE, the Cities of Red Deer and Lethbridge and the FIRM Group.

TCE was particularly active respecting this issue, and proposed to define standard service as follows (TCE wording italicized to illustrate their proposed changes):

“AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of two lines of transmission circuit and two transformers to supply an individual POD for peak loads at or above 15 MVA and to generally consist of a single radial transmission circuit and a single transformer to supply an individual POD for peak loads below 15 MVA.

For reasons further described below, the Board has determined that the definition of “AESO Standard Facilities" as set out in the T&Cs of the Application should be approved as filed by the AESO. The Board has addressed the views of the other parties below.

Reliability Obligations Required by Legislation
The Board notes that the Transmission Regulation has imposed additional obligations on the AESO to ensure that its reliability standards meet or exceed generally accepted North American reliability standards. The AESO’s obligations in respect of reliability standards are set out in Part 2 of the Transmission Regulation, reproduced in part below:

8(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must

(a) plan a transmission system that satisfies reliability standards, unless the ISO decides that to do so would not provide for a safe, reliable or efficient transmission system;

(b) ensure that transmission facilities adhere to reliability standards;

(c) monitor and ensure overall reliability of the interconnected electric system;

(d) comply with directives of the Board;

…

(2) A decision by the ISO under subsection (1)(a) that a reliability standard would not be safe, reliable or efficient must be filed by the ISO with the Board for approval.

75 AESO Argument, p. 47 of 58
The phrase “reliability standards” as referenced in Section 8 of the *Transmission Regulation* is defined in Subsection 1(1)(e) of the regulation as follows:

1(1)(e) “reliability standards” means the reliability standards agreements, criteria and directives of the Western Electric Coordinating Council and the North American Reliability Council, or their successor organizations, and reliability standards, agreements, criteria or directives of any similar entity recognized by the ISO;

The above referenced passages of the *Transmission Regulation* mandate the AESO to adhere to reliability standards that meet or exceed standards adopted by the North American Reliability Council (NERC) and the Western Electric Coordinating Council (WECC). While the *Transmission Regulation* provides some discretion to the AESO to deviate from specific elements of either the NERC or WECC standards, the AESO faces a reverse onus requirement to prove that compliance with a particular aspect of the NERC and WECC standards would not be safe, reliable or efficient in the Alberta context.

The AESO submitted that it adopted both the NERC and WECC Reliability Criteria as the basis for its own Reliability Criteria document. The Board notes that no evidence was provided during the Application proceeding to suggest that the AESO Reliability Criteria did not reflect the NERC and WECC Reliability Criteria to the extent required by the *Transmission Regulation*. As the AESO has not made any application pursuant to Subsection 8(2) of the *Transmission Regulation* seeking relief from the reliability standards, the Board considers that the obligation on the AESO to maintain these standards remains fully intact.

The Board notes that a comprehensive update to the AESO reliability standards was prepared by the AESO (AESO Reliability Criteria) and was circulated for stakeholder comment. The AESO’s Reliability Criteria document was filed in this proceeding by the AESO in response to an information request. In addition, a matrix document containing stakeholder comments on the AESO’s Reliability Criteria and the AESO’s responses to these comments was also filed in the Application proceeding.

The Board finds that the Point of Delivery (POD) Criteria described in Section 4.5 of the AESO Reliability Criteria document reflects the WECC’s determination within its Reliability Criteria that interconnection facilities based on a single radial circuit and single transformer are acceptable in relation to WECC’s standards. Further, it is also notable that the Section 4.5 POD Criteria expressly indicate that there is a risk of firm and opportunity load having to be shed in the event of an outage of the radial interconnection elements. Accordingly, the Board considers that AESO customers contemplating the interconnection of a new load will be aware of the potential for electric service disruption if they choose to rely solely on the facilities described by the POD Criteria.

The Board notes that the AESO indicated in its matrix that distribution customers and industrials would be treated the same. However, the Board notes that it might be argued that, if a multi-customer POD waiver were to be granted to distribution utilities with the result that distribution utilities could obtain system cost treatment for most or all of the costs of a second

[76] Exhibit 02-025-001, p. 1
[77] Exhibit 02-025-001, EPCOR-AESO-001 response.
[78] Exhibit 02-021-001, CITIES-AESO-010, Attachment A
[79] Exhibit 02-021-00 (see AESO “Comment 56”, pp. 23-24)
transformer/second line while an industrial customer could not, this would constitute undue
discrimination. The Board considers this concern to be valid. As such, this concern contributed
to the Board’s decision to disallow the AESO’s multiple customer POD contribution waiver, as
further discussed in Section 6.1.5 of the Decision.

**Economic Rationale for AESO Standard Facilities Definition**
The Board notes that certain parties suggested that POD service standards should be higher than
a single line/single transformer standard and therefore advocated the adoption of a higher
standard on the basis that the AESO has a duty to ensure that an equal quality of service is
provided to all customers.

The Board notes that it was readily acknowledged by the AESO in the course of the proceeding
that the adoption of one-line/one-transformer as the normal standard would not provide a
minimally acceptable level of service for some customers. That is, the AESO has made it clear
that it accepts that some customers would never consider reliance on an interconnection based
solely on AESO Standard Facilities to be acceptable. As noted by the Cities, this implies that a
substantial contribution would be required just to achieve a minimum acceptable level of service.

The Board does not find that the AESO has an obligation to equalize service levels to the extent
advocated by some parties. The Board notes Decision 2001-6 where it held that there is no
analogue to the postage stamp rates principle that would mandate the AESO to provide postage
stamp service.\(^{80}\) The Board also notes that the notion of designating costs as system or customer-
related on the basis of whether a looped or a radial interconnection was built was adopted by the
Board in Decision 2001-6 in spite of the fact that certain parties had argued in that proceeding
that it would be unfair for customers served by a less reliable radial interconnection to have to
pay a contribution while customers who received more reliable looped service paid no
contribution.\(^{81}\)

The Board considers that the evaluation of a set of reliability criteria, including the POD service
level criteria, is influenced by economic considerations. That is, the AESO must consider the
extent to which the costs of providing higher standards of facilities justify the increase in benefits
to users in the form of increased reliability. In addition, the Board also considers that the manner
in which the benefits of increased reliability are distributed amongst the AESO’s customers
should also be a significant consideration in how aspects of the reliability criteria, including the
AESO Standard Service definition/POD Criteria, are devised.

In this regard, the Board notes that the AESO’s decision to adopt within its reliability criteria the
WECC practice of excluding radial customer interconnections from the general scope of the
AESO Reliability Criteria. This reflects the fact that an outage on a radial interconnection
“downstream” of the bulk system will affect the radially connected customer, but should have
limited impact, if any, on other AESO customers not served by the radial interconnection. As a
consequence, the Board considers that the benefit of increased electric service reliability arising
from higher standard and/or redundant interconnection facilities accrues primarily to the radially
interconnected customer rather than to AESO customers at large.

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\(^{80}\) Decision 2001-6, p.74

\(^{81}\) Decision 2001-6, page 74
Additionally, the Board notes that the need for absolute reliability amongst AESO customers is unlikely to be uniform, since different customers will experience different types and severity of consequences from electric service disruptions. The Board notes that alternative arrangements (such as backup power supplies), other than interconnection facilities may be made to deal with potential service disruptions. As such, the Board considers it to be economically efficient that the contribution policy should provide appropriate economic siting signals which pass along the costs arising from the installation of facilities beyond standard facilities to the specific AESO customer requesting the interconnection.

The Board considers that the principal concern that the AESO’s existing customers might have with a minimum standard service definition relates to the possibility that the cost of optional facilities might actually dissuade a customer from making an investment and interconnecting with the system. If this were to occur, existing customers would not enjoy the benefit of being able to transfer a portion of the burden of the AESO’s embedded system costs to a new customer. However, based on evidence available in this proceeding, this is not a substantial concern of the Board at this time. In particular, the Board notes that, while TCE presented analysis in its argument designed to show the high economic costs that would arise from a prolonged disruption in service, a corollary of TCE’s analysis is that customers will place a high value on reliability assurance at the time they are considering their initial investment as well. As a result, absent information to the contrary, the Board expects that customers facing substantial optional interconnection facility costs should generally be presumed to be willing to make a decision to invest in providing the minimum level of reliability that their operations require.

Analysis of Interconnection Facilities at Existing AESO PODs - Rate Shock
Regarding TCE’s submission that the AESO and its predecessors have generally provided a second transformer at system rather than customer expense, the Board does not agree. In arriving at this determination, the Board takes particular note of the AESO’s rebuttal evidence which suggests that a significant number of the second transformers may have been installed because the AESO and/or its predecessors determined that the cost of an interconnection using a configuration with two smaller capacity transformers was more efficient or cost effective than an interconnection devised using a single large capacity transformer. In any event, the Board finds that even if TCE’s interpretation of the statistics was to be accepted, it is clear from the statistics provided during the proceeding that a significant number of PODs greater than 15 MVA are presently served by a single transformer. As such, the Board is concerned that the adoption of TCE’s additions to the proposed AESO Standard Facilities definition could establish a de facto minimum standard for a second transformer in instances where such facilities have not historically been deemed to be warranted.

82 At p. 44 of its Argument, TCE estimated that the value of expected energy not served arising from a 7 day disruption of a 90% load factor 30 MW industrial load would be approximately $54.4 million.
83 The Board is in general agreement with the AESO’s observation at p. 47 of its Argument that a greater emphasis should be placed on the aspect of the AESO Standard Facilities definition focusing on the “least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria” and comparatively less on the one-line/one-transformer aspect of the definition. Conversely, however, the Board does not agree with the suggestion of AE the one-line/one-transformer standard is inherently contradictory with good transmission practice and should thus be removed from the decision. That is, notwithstanding that the good transmission practice should govern decision making in specific situations, the Board considers that the one-line / one-transformer standard provides a useful reference point to AESO customers and may appropriately be included in the AESO Standard Facilities definition.
The Board further notes that, to the extent that potential AESO customers are able to assess the
costs and benefits associated with higher or lower levels of reliability prior to committing to an
investment, such customers will not be harmed and do not experience rate shock in the manner
suggested by TCE. As such the Board does not agree with TCE’s view that the adoption of the
AESO’s proposed Standard Facilities definition constitutes rate shock for new customers.

Alignment with Discos Contribution Policies
The Board notes that two documents filed during the proceeding received some prominence in
some parties’ discussions of the AESO Standard Service. These documents are the “Distribution
Point-of-Delivery Interconnection Process Guideline – Typical Supply Arrangements” (Typical
Supply Arrangements Document) and the “Distribution Point-of-Delivery Interconnection
Process Guideline – Standard of Service” (Standard Service Document). The Board
understands that these documents were prepared in conjunction with the new Interconnection
Redesign Process initiative described in Section 6.3 of the Application.

The Board notes that TCE has pointed to the Typical Supply Arrangements Document as being
supportive of its contention that, at a breakpoint of approximately 15 MVA, customer
interconnections tend to require interconnection facilities beyond a single line/single transformer
configuration. TCE also pointed to the Standard Service Document as supporting its view that
the determination of standard interconnection facilities should be based on a maximum
restoration time standard. The Cities similarly appear to suggest that aspects of the
Interconnection Redesign Process documents may be interpreted as defining minimum standards.
The Board does not share this view.

The Board understands that an over-riding goal of the Interconnection Redesign Process
initiative is to streamline and standardize the interconnection process with an eye towards
shortening timelines, including the time required to obtain Board approval(s). In this respect, the
Board considers that the identification of common aspects of interconnection projects including
typical service and facility arrangements should be helpful in reducing the turn-around time for
processing interconnection applications. The Board notes, however, that when it is called upon to
assess the overall need for an interconnection project pursuant to Section 34 of the EUA, the
Board’s determination of need is typically straightforward because the technical specifications
have been worked out by the end-use customer and the AESO in advance, based primarily on the
customer’s requirement for a defined level of reliability. Accordingly, the Board notes that when
it approves the need for a customer interconnection project, the Board does not consider that
such an approval should imply, in any respect, that the Board agrees that the facilities built for an
interconnection project should be regarded as standard facilities for the purposes of applying the
contribution policies of either the AESO or the applicable Disco.

In this regard, the Board notes that a disclaimer warning parties not to infer interpretations of
contribution policies is included in the introductory sections of both of the Interconnection
Redesign Process documents filed in the Application proceeding. The Board considers that this
disclaimer is important and needs to be heeded in the present case.

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84 Exhibit 23-016 (Response to BR-TCE-1)
Arrangements”
86 Exhibit 02-033-004, TCE.AESO-238(a) Attachment entitled “Distribution Point-of-Delivery Interconnection
Process Guideline – Standard of Service”
87 Exhibit 30-006, page 1 and Exhibit 02-033-004, page 1
Notwithstanding the above, the Board agrees with the comment of the Cities that it may be somewhat unrealistic to expect that these documents could not have some influence on the determination of standard service. It is of concern to the Board that the above referenced documents could be interpreted such that, for Discos, facilities above a single line and transformer, could be considered standard for loads above a certain level. This could provide incentives for customers to generally favour interconnection to a distribution system over interconnection to the AESO system.

The Board considers that it would to be an economically inefficient and undesirable result if the type of interconnection (i.e. distribution vs. transmission) sought by a customer was driven more by a Disco’s more attractive contribution policy than on the basis of which type of interconnection was the most technically sound and cost efficient. Accordingly, the Board considers that it is important for the standard service definitions of the AESO and Discos to be aligned to the extent possible. For this to occur, the Board considers that an evaluation and debate must take place regarding the extent, if at all, that a minimum service norm as discussed in the Interconnection Redesign Process should be set at a higher level than a Disco’s standard facilities definition for a Disco’s contribution purposes. The Board considers the above described exercise to be an essential aspect of the harmonization of Disco and AESO contribution policies that should occur as soon as practicable. The Board will provide additional directions in regard to AESO/Disco harmonization process in Section 6.3.2 of this Decision.

6.1.4 Maximum Investment Formula

The AESO noted that in Decision 2001-6, the Board had supported a criterion for the design of the maximum investment formula (presently referred to as the “roll-in ceiling” in the existing tariff) such that approximately 80% of interconnection projects would not require a customer contribution. The AESO noted that it was posited by the AESO’s predecessor during the course of the proceeding leading to Decision 2001-6 that setting a roll-in ceiling in this manner would have the effect of minimizing intergenerational inequities.

In the Application, the AESO noted that the use of the roll-in ceiling had not met the target of 80% of projects not requiring a contribution with 20% of projects requiring some contribution be paid. Instead, it was noted that, in practice, the roll-in ceiling has resulted in customers being required to pay a contribution only in respect of about 10% of interconnection projects.

The Application also noted that while the roll-in ceiling reflected some consideration of the forecast amount of transmission rate revenues to be paid by a customer following the customer’s interconnection, the major driver of the size of the roll-in ceiling for a specific project related to the length of the DTS contract signed by the customer (the “commitment term amount”).

In an effort to try to meet the 80/20 target more consistently, the AESO has proposed a new maximum investment function in the Application. The proposed maximum investment function does not include a Commitment Term component. Instead, the AESO has proposed a simpler formula under which a customer would be granted an investment allowance of $27,000 per MW of contracted DTS load, per year of DTS contract term. A graphical representation of the roll-in ceiling and the maximum investment function proposed in the Application are shown in Figure 6.1.2.88

88 Application, Section 6, page 10
As discussed above in Section 6.1.1 the Board considers it is of primary importance that the contribution policy should send appropriate economic siting signals to new customers. The Board considers the design of the maximum investment function to be central to the goal of sending appropriate economic signals through the contribution policy. While the Board notes that the AESO has attempted to achieve a balance between economic signals and administrative simplicity, the Board considers that the maximum investment function proposed by the AESO is overly simple. As a result, it does not achieve an appropriate balance between simplicity and appropriate economic signals.

The primary concern of the Board with respect to the AESO’s proposed investment function is that it emphasizes revenues; that is, the AESO has considered the revenue stream it will receive from a prospective connection, rather than costs as a driver of the design. The Board agrees with the AESO that the current roll-in ceiling formula places a disproportionately high emphasis on the commitment term amount of the formula when compared to forecasted revenues. However, it is inappropriate to presume that a desire to downplay the influence of the commitment term component of the current roll-in ceiling formula results in a general preference for revenue based investment formulas over cost based formulas.

The Board considers that the underlying rationale for the consideration of revenues in the context of a contribution investment policy relates to the manner in which a new customer interconnection may benefit existing customers through a broader sharing of embedded system costs. In this context, the incremental transmission revenue generated by connecting the new customer is also the maximum level of the “willingness to pay” of existing customers. Furthermore, since the Board considers that a new customer may normally be presumed to be seeking an interconnection in order to obtain the benefits of electrical service rather than an investment allowance per se, the Board considers that the new customer should be provided the incentive to commit an investment as long as the costs of any required interconnection facilities are offset. Thus, there is the potential risk of creating a substantial difference between the respective willingness to pay of the new customers and that of existing customers. The difficulty in creating a utility investment policy is to determine how to design a maximum investment allowance function that will fall at a reasonable level within this range.

Based on evidence brought forward in this proceeding, the Board has determined that cost, not revenue, is the appropriate starting point for establishing the investment policy. As such, rather than being a driver of the investment policy, the Board considers that the primary role that transmission tariff revenues should play is to establish the upper limit of the investment allowance. That is, if the transmission revenues expected to be generated by a new DTS customer over the customer’s contract term are estimated to be less than the expected cost of a standard facility interconnection, the amount of maximum investment function should be limited to no more than the amount of the estimated incremental transmission revenue.

While the Board notes that the AESO has indicated that it has adopted a revenue based approach for the AESO’s maximum investment proposed in the Application, the Board considers that the AESO’s proposal is, in reality, based on the observed and/or derived costs for a set of interconnection projects of varying sizes. In contrast, the Board notes that the revenue based aspect of the AESO investment proposal related to the AESO’s decision to force the derived

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89 Application, Section 6, Pages 8-9
investment line through a zero intercept. The Board understands that this constraint was imposed in an attempt to reflect the fact that the AESO’s proposed rate design did not include a customer charge.\footnote{The AESO indicates at Tr. Vol. 3, pages 875-876, that the choice of a zero intercept reflected the AESO’s proposed rate design in which DTS rates did not have a customer charge component.} However, the Board considers that the AESO’s adoption of the zero intercept constraint acted in combination with the AESO’s adoption of a linear form for the investment function to create a function that is excessively steep. As a result, the Board considers that the AESO’s proposed maximum investment function tends to provide an insufficient allowance for small interconnection projects and an excessive allowance in respect of comparatively larger projects.

In addition to these concerns, it is also not clear to the Board that a linear investment function will properly reflect the reduced rate at which interconnection project costs increase as peak load rises. In this regard, the Board was strongly persuaded by the testimony of the IPCAA panel\footnote{Transcript Vol. 6, pp. 1587-1589} that significant scale economies occur as the size of interconnection projects increases. As a result, the Board considers that such scale economies should be reflected in the functional form of the maximum investment curve. The Board also takes note of evidence introduced by TCE which concretely illustrated the existence of significant scale economies in respect of both transformation equipment and transmission lines.\footnote{Exhibit 23-019-001 (FIRM-TCE-3 Schedule A) and Exhibit 23-019-002 (FIRM-TCE-3 Schedule B)} In light of the Board’s findings with respect to scale economies, the Board considers that it is appropriate for the AESO to assess the merits of a non-linear rather than a linear form for the maximum investment function along the lines of the “0.6 power rule”\footnote{The chairman discussed the subject matter of potential scale economies in respect of interconnection projects with the IPCAA panel at TR. Vol. 6, pp. 1587-1589. In the course of that exchange, the chairman discussed with the IPCAA panel the notion that engineers typically apply a rule-of-thumb which postulates that typical engineering projects should rise by only about 60% for any 100% increase in the size of the project. While it is not the intention of the Board to prescribe a specific non-linear functional form for the maximum investment function to the AESO, the Board considers that this “point-six power rule” may provide a useful starting point for the AESO’s investigations.} discussed by the Chairman and IPCAA.

The Board noted, with interest, IPCAA’s proposed approach whereby a threshold above the proposed allowable investment is incorporated into the maximum investment allowance. The Board notes that it is in the interest of existing AESO customers that the interconnection of new customers be encouraged so long as the interconnection costs to be funded by existing customers are less than the incremental transmission tariff revenues expected to be generated. Accordingly, the Board considers that it is appropriate that the maximum investment function to be applied in the longer term should include some additional “tolerance” above the amount that would be provided under an investment function strictly designed to reflect average costs. However, the Board is not prepared at this time to adopt IPCAA’s recommendation that the investment function should be increased by 25%. Instead, the Board considers that an appropriate level for this “average-cost plus” threshold should be the subject of future study of the extent to which interconnection project costs of a comparable capacity may be expected to exceed the average for that size of project.

Notwithstanding the Board’s suggestion to review the merits of a non-linear maximum investment function and provide its findings at the next GRA, the Board notes that the notion of a non-linear function was discussed only at a conceptual level during the Application proceeding. As such, the Board considers that a linear maximum investment function must continue to be utilized in the short term. Accordingly, the Board hereby directs the AESO to amend Article 9.4
of the Terms and Conditions proposed for the Application such that a minimum investment allowance reflects:

- A minimum investment allowance of $2.5 million; and
- An additional investment of $100,000 per MW of project capacity.

The AESO is further directed to provide a copy of the proposed adjustments to Article 9.4 with the refiling Application pursuant to this Decision.

In respect of the longer term beyond 2006, the Board directs the AESO to conduct further study so that it may devise a more comprehensive investment function proposal which avoids the Board’s concerns with the AESO’s 2006 Application and reflects the design principles described by the Board in this Decision. The Board considers that this task will involve several distinct steps, as reflected in the following list of Board directions:

1. The Board hereby directs the AESO to conduct a study for the purpose of devising a simplified maximum investment function. Such study to be completed in time for review no later than the 2008 GTA proceeding. The study should incorporate a sufficient number and diversity of data points to enable the study to consider the current costs of several different interconnection project sizes. Interconnection project costs for the purposes of the investment function study should only reflect the costs of standard facilities as described in the AESO Standard Facilities definition approved by the Board in this decision.

2. On the basis of the results of the study described in the preceding direction, the AESO shall recommend an investment function that represents the average cost per MW of capacity. The Board expects that the resulting interconnection cost function derived will exhibit significant economies of scale and, as a result, may be non-linear in nature. For the purposes of the remaining steps of the Board’s maximum investment function directions, the average cost function derived in accordance with this step will be referred to as the “Raw Interconnection Project Cost Function”.

3. In accordance with the notion of a tolerance as discussed in the argument of IPCAA, the Board directs the AESO to analyze the results of the above study for the purposes of determining an appropriate multiplier such that approximately 80% of the projects included have a cost greater than implied by the Raw Interconnection Project Cost Function fall within the selected tolerance multiplier.

The Board directs the AESO to present the results of the above analysis for review no later than the time of filing its 2008 GTA, along with its proposal for an appropriate maximum investment formula.

### 6.1.5 Contribution Waivers for Expansion at Multiple Customer PODs

In this Application, the AESO proposes to waive customer contributions in respect of transmission projects at AESO PODs where multiple users are served by a distribution utility.

The elements of the AESO’s Multi-POD waiver are described in Article 9.5 of the AESO’s proposed T&Cs. Specifically, Article 9.5 provides that, effective January 1, 2006, the AESO

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94 This direction is based on the IPCAA analysis described at page 34 of IPCAA’s argument submission.
would waive all or part of the customer contribution that would otherwise be assessed against a
distribution utility for transmission facility expansions at a multiple-user POD on condition that
the distribution utility:

- Provides sufficient documentation to demonstrate that the customer contribution arises
  from a transmission project required by multiple end-use sites served by the distribution
  utility;
- Executes a twenty year System Access Service Agreement in respect of the multiple-user
  POD; and
- Agrees to flow through a pro rated share of the customer contribution that would
  otherwise apply in respect of a transmission expansion at a multi-user POD to identifiable
  customers of the distribution utility with loads greater than 2 MW.

The proposed Article 9.5 also specifies that the proposed contribution waiver would not be
available in respect of any transmission facilities above and beyond the AESO Standard
Facilities deemed to be required to provide acceptable service to the distribution utility.

The AESO submitted that the availability of a contribution waiver in respect of distribution
utility PODs serving multiple customers was necessary because:

(1) regulated utilities have an obligation to serve regardless of any limits imposed by the
AESO’s contribution policy; and

(2) distribution utilities have little if any influence over the amount, location, or timing of the
load growth that they are obligated to serve.

ATCO Electric, the Cities of Lethbridge/Red Deer and FIRM supported the AESO’s multiple
customer POD waiver proposal. EnCana, IPCAA and TCE opposed the proposal, primarily on
grounds that it would create discrimination between the AESO’s industrial and distribution
utilities. Alpac indicated that while it did not have a view on the multiple-customer POD waiver
proposal at the present time, it considered that other aspects of the AESO’s proposed
contribution policy should be determined by the Board before further consideration is given to
the multiple customer POD waiver.

The Board agrees with the AESO’s observation that there are fundamental differences between
distribution utilities and industrial customers. In particular, the Board agrees that whereas a
regulated distribution utility has a statutory obligation to provide adequate service in response to
load growth that it cannot dissuade or otherwise control, there is no analogous requirement on an
industrial customer to ensure that it receives electric service at some predefined minimum level
of service and reliability. The Board further notes that, unlike the AESO’s industrial customers,
the AESO’s distribution utility customers have the ability to collect revenues reflective of the
prudent costs of carrying out their statutory obligations through the regulated distribution
utility’s tariff. As such, in the event that a transmission facility investment required by a
regulated distribution utility is not fully covered under the AESO’s contribution policy, the
distribution utility should generally be able to expect that the costs of a customer contribution
paid to the AESO may be recovered by flowing the cost of the customer contribution through the

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In addition to supporting the multiple customer POD contribution waiver, AE also indicated that the availability
of such a waiver should be back dated to January 1, 2005 rather than only being available as at January 1, 2006.
regulated distribution utility’s revenue requirement. By contrast, industrial customers do not enjoy a comparable guarantee that they will be able to pass along any customer contribution costs through the costs of the products they may produce.

Notwithstanding these noted differences, the Board is not persuaded that it is necessary or appropriate to grant a waiver from customer contributions otherwise payable by the distribution utility to the AESO. In particular, given that a distribution utility should generally be able to recover customer contributions arising from AESO facility projects through the distribution utility’s own tariff, the assessment of a contribution waiver is reduced to a question of whether the contribution costs should be spread more narrowly through a specific distribution utility’s tariff or shared more broadly under a waiver scenario that would see these costs being absorbed within the AESO’s revenue requirement.

In this regard, the Board notes that it was previously determined in Decision 2001-6 that the AESO’s predecessor would not violate the principle of postage stamp rates by adopting a contribution policy that could require some distribution utilities to pay somewhat higher contributions than other distribution utilities. The Board further notes that while narrative in the Application appeared to suggest that the AESO’s existing contribution policy might be regarded as violating certain aspects of postage stamp principle, the AESO confirmed in an information request response that statements on p. 88 of the Application linking the existing contribution policy to a possible postage stamp principle violation had previously been disposed of in Decision 2001-6.

The Board considers that it is both consistent with past practice and consistent with the desire to send efficient pricing signals through the contribution policy that customer contribution costs incurred by a distribution utility should be recovered through the distribution utility’s own tariff. Accordingly, the Board hereby denies the AESO’s proposed Article 9.5 of the Application’s proposed T&Cs in its entirety.

6.1.6 Other Contribution Policy Issues

6.1.6.1 Application of Contribution Policy to Dual-Use Sites

In the Application, the AESO noted that its existing contribution policy determines the extent to which the load or supply customer contribution policies apply to a dual use customer using a formula based on the ratio of the DTS and STS contract capacity to the aggregate contract capacity at the customer’s site. Under this formula, the amount payable under the load contribution policy is determined in accordance with the following formula:

\[ \frac{\text{DTS}}{\text{DTS} + \text{STS}} \times \text{customer-related costs} \]

Similarly, the amount payable as a generator in respect of local interconnection costs is determined as:

\[ \frac{\text{STS}}{\text{DTS} + \text{STS}} \times \text{cost of the local interconnection} \]

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96 Decision 2001-6, page 55
97 BR-AESO-019. (Note: The AESO’s response to BR-AESO-019 goes onto indicate that the passage found at p. 88 of the Application implying a possible postage stamp violation should be considered to be withdrawn from its evidence.)
The AESO noted that the dual-use ratio was intended to provide a reasonable sharing of customer-related costs between load and supply in consideration of the fact that a significant portion of the load customer’s interconnection costs may be rolled into rates through the operation of the roll-in ceiling while the generator costs are paid fully by the generator as a customer contribution. The AESO noted that, in particular, the dual-use ratio was beneficial in limiting the amount of contribution provided on the basis of the commitment term component of the roll-in ceiling which, since it is not revenue based, would provide a contribution to generators without a corresponding revenue stream.

The AESO indicated, however, that because its proposed maximum investment policy had eliminated the commitment term amount from the roll-in ceiling formula, it was no longer necessary to address potential mismatches between investment and revenue through the dual-use formula. Accordingly, the AESO proposed to eliminate the dual-use formula in favour of the application of a “load first” principle. Under this method, the AESO proposed to determine the dual use customer’s interconnection contribution by first determining what the contribution would be if the customer were treated as a load customer. Accordingly, if the application of the load customer contribution provided full coverage for the cost of a standard facility interconnection, the load first principle would mean that no contribution would be required. In the event that the application of the maximum investment function for load did not cover the full cost of providing a standard facility interconnection, the customer contribution would be the residual cost after subtracting the maximum investment allowance from the cost of the standard facility interconnection, as illustrated from the following formula reproduced from the Application:

\[
\text{customer contribution} = \frac{\text{total customer-related costs for load and generator}}{\text{less local investment for load}}
\]

The AESO’s proposed “load first” formula was supported by IPCAA and by TCE but was opposed by FIRM.

The Board notes that the AESO’s proposition that a “load first” principle should apply in determining the contribution for dual-use customers is strongly premised on the elimination of the commitment term amount from the maximum investment formula. This would be replaced by an investment formula driven entirely by the number of MWs of DTS contract capacity and contract terms that the customer signs up for.

However, the Board notes that while the maximum investment function adopted by the Board in Section 6.1.4 of the Decision above no longer includes a significant commitment term component, the formula prescribed by the Board still provides a minimum contribution of at least $2.5 million. Accordingly, while the Board considers that there is a better match under the new load contribution policy between interconnect costs and DTS revenues, the adoption of the AESO’s proposed “load first” formula would still provide a substantial contribution to generators who sign up for minimal DTS capacity.

In light of this finding, the Board considers that it is still necessary to maintain the dual-use formula to ensure that AESO customers that are primarily generators are not able to gain an effective exemption from the clear policy intent of the Government’s Transmission Policy and the Transmission Regulation whereby generators are to pay for their local interconnection costs. Accordingly, the Board hereby directs the AESO, in its refiling, to re-instate the dual-use
formula as described in Article 9.3 of T&Cs of the currently approved tariff. The Board considers that alterations to the wording of the dual-use clause should only be done for the purposes of maintaining consistent numbering and references to other parts of the AESO’s T&Cs.

6.1.6.2 Staged Load

The AESO proposed\(^{98}\) to apply the customer contribution policy in a manner that would accommodate material increases or decreases in a customer’s load, provided the customer signed a DTS contract with a term that extended a minimum of five years after the start date of the last staged contract capacity. Under this proposal, the maximum investment allowance accounting for staged changes in load, would be made available to the customer at the start of the project. However, it would be adjusted to reflect the staged nature of the load by taking the present value of the investment in the incremental load for the period of the contract term after the staged increase or decrease in the contracted capacity was to take place.

The AESO’s staged load proposal was supported by FIRM. However, FIRM also submitted that if the staged load did not materialize as planned for the purposes of determining the available investment allowance, the customer receiving staged treatment should be obligated to repay any excess facility investment allowance that may have been based on the assumed staging of the contracted load.

The Board notes that no parties opposed the proposal to permit the staging of load levels for the purposes of determining maximum investment allowances. The Board likewise supports and approves this proposal. However, the Board notes that the proposal to permit load staging in the determination of available investment is not specifically described in the AESO’s proposed Article 9.4 or elsewhere in the AESO’s Article 9 contribution policy T&Cs. As such, the Board shares the concern of FIRM respecting the obligation of a customer to provide a refund if the staging assumptions used initially do not materialize.\(^{99}\) Accordingly, the Board hereby directs the AESO to propose a specific additional provision of Article 9 which more specifically describes the consideration of staged loads for both investment allowance and refund determination purposes with its refiling Application.

6.1.6.3 Distribution vs Transmission Interconnections

The Board notes that Article 9.1 of the existing tariff’s T&Cs requires the AESO to assess the appropriate way of providing service to a customer requesting a new point of connection or expansion of an existing point of connection. Article 9.1 further provides that, if the AESO determines that the most economic option for providing that service to a customer is a distribution-level extension or isolated generation or, if the customer’s request primarily represents a shift of supply or demand from an existing point of connection, then the customer will pay the full cost of the project.

The Board notes that the parts of the proposed Article 9.1 describing the AESO’s obligation to assess the appropriate type of interconnection that should be provided to a customer are largely unchanged from the comparable part of the existing Article 9.1. The Board concludes, however, that some adjustment of Article 9.1 is necessary to bring it into alignment with the “optional

\(^{98}\) Application, Section 6, pages 11-12

\(^{99}\) Despite this concern, the Board notes, however that the AESO has the right to require a refund in this situation pursuant to the AESO’s proposed Article 9.7.
service” concept discussed in Section 6.1.3 above. Of specific concern to the Board is this passage from the proposed version of Article 9.1:

If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), or that the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension (“the project”). [Emphasis added].

The Board is concerned that, as currently proposed, the referenced portion of Article 9.1 does not align with the concepts of AESO Standard Service and Optional Service as described elsewhere in this Decision. In particular, the above referenced passage indicates that no investment allowance will be permitted on any portion of the costs of a transmission interconnection project when the AESO has determined that a distribution project is more economic. However, the Board considers that it is appropriate that an investment allowance should be permitted in respect of that portion of a project’s costs up to the cost of the foregone lower cost distribution or isolated generation service option.

The Board agrees, however, that a full customer contribution should be required in respect of the difference in cost between a lower cost distribution option and the selected transmission option. Accordingly, the Board directs the AESO to amend Article 9.1 to reflect the Board’s above noted findings as part of its refiling.

6.1.6.4 Discount Rates

Article 9.12 of the proposed T&Cs updated the formula used to determine the discount rate that may be used for various purposes within the contribution policy. The Board notes that no parties opposed the AESO’s proposed changes. The Board also supports the proposed changes. Accordingly, the Board hereby approves Article 9.12 as filed.

6.1.6.5 Common Facilities

Article 9.8 of the Application’s T&Cs proposed to change the way the AESO deals with situations arising when one or more additional customers make use of local interconnection facilities originally built for and funded by an existing AESO customer.

Unlike the existing tariff’s Article 9.8, which describes the allocation of interconnection facility costs amongst existing customers and any newly interconnecting customers using the same facilities, the proposed Article 9.8 simply provides that in any situation in which a new customer makes use of an existing customer’s local interconnection facilities, the cost of such facilities will simply be deemed to be a “Common Facility” as defined under Article 9.8 and the costs will then be designated as system-related to be borne by all AESO customers. The AESO indicates in the Application that its proposed treatment of common facilities for the purposes of Article 9.8 was devised to comply with Subsection 16(4) of the Transmission Regulation.

The AESO stated that it had interpreted the Government’s choice of the words “all users” within Subsection 16(4) to denote a specific policy intent as set out in the following response to Board IR 026:

… “all users” as “all users of the transmission system” simply because there is no qualification of usage in section 16(4). For example, if limitation has been intended,
section 16(4)(a) could have stated “all users of those facilities; or used other qualifying words.  

In argument, FIRM took issue with certain aspects of the AESO’s interpretation of Subsection 16(4) and in particular with the broad nature of the words “all users” in Subsection 16(4). In FIRM’s submission, the reference to “all users” should be interpreted as “all users of those facilities”. FIRM noted that this interpretation would be consistent with the principle of cost causation where costs should be borne by those causing the costs and with the Board’s long standing practice of applying a revenue test for shared facility costs. FIRM further submitted that, if the intent of the drafters of the legislation had been to overturn well established regulatory practice, the Transmission Regulation would have included specific language, such as “all users of the transmission system”, to effect such a change. In the absence of such language, FIRM submitted that the meaning of “all users” within Subsection 16(4) should be interpreted in a manner consistent with established Board practice and cost causation principles. FIRM noted that while its comments were primarily devised in relation to the circumstances of load customer interconnections, FIRM considered that a similar interpretation of Subsection 16(4) (references to “all users” should be interpreted as “all users of those facilities”) should also be applied when one or more new customers are added to the local interconnection facilities of an STS customer. FIRM further submitted that, if the revenue test in relation to shared facilities were eliminated through the adoption of the AESO’s proposed Article 9.8, a door to potential abuse in the future could be opened. FIRM submitted, for example, that a large customer needing new facilities involving a significant customer contribution may attempt to avoid a contribution by having another customer, perhaps an affiliate, request a second connection somewhere along the new facility line for load smaller than the original facility. In this situation, FIRM suggested that the AESO’s proposal would have the effect of funding the interconnection facilities of both of the customers in the example at the expense of all users of the system.

In reply to FIRM, the AESO submitted that additional background pertinent to the interpretation of Subsection 16(4) is provided by the Government’s policy paper Transmission Development: The Right Path for Alberta which states:

Local “system” upgrades typically include items such as changes to stations A and B (i.e. circuit breaker change-outs, protection upgrades), reconductoring of Line A-B, or other modifications to the local system to accommodate the generator. These costs will be considered “system” costs and will not be recovered specifically from a particular generator but will be treated like all other system costs.

Having regard to this passage, the AESO submitted that its proposed re-designation of customer costs as system costs as described in Article 9.8 aligns with both the Transmission Regulation and with government policy, and should therefore be approved as filed.

While the Board acknowledges the public policy concerns raised, the Board must approach this issue first as a matter of statutory interpretation. If the language used by the legislation is clear, then the Board must give effect to it. To construe any legislation, including its governing legislation, the Board applies ordinary principles of statutory interpretation. The Board will

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100 While not specifically indicated in FIRM’s argument, the Board understands that the referenced passage is part of BR-AESO-026 (Exhibit 02-016).

101 Exhibit 030-027
endeavour to give statutory language its plain and ordinary meaning having regard to its context. The Board will also interpret provisions in different enactments with similar subject matter so as to avoid conflict between them.

Accordingly, the Board has first approached the question of the extent to which interconnection costs are to be shared among multiple customers by considering the language used in the beginning of Subsection 16(4) which reads as follows:

16(4) If another person makes use of the facilities for which a local interconnection cost has been paid, (emphasis added)

As is clearly shown in the above provision, the use of the modifiers “another” before “person” and “the” before “facilities” narrows the consideration of interconnection costs to a particular customer in respect of a particular interconnection as opposed to all customers and all interconnections in general. This introductory provision must then be read as part of each of the subsections that follow. Thus the whole section read together would be as follows:

If another person makes use of the facilities for which a local interconnection cost has been paid, the cost of the use of those facilities by that other person or persons must be allocated to all users in accordance with the ISO tariff; and the original local interconnection cost, or a portion of it, must be refunded to the person who paid it in accordance with the ISO tariff.

When read as a whole, the provision supports the interpretation that the words “all users” is a reference to the cost of the use by those specific users of the interconnection facilities that are now being used by one or more persons. The Board has concluded, based on the language of Subsection 16(4) of the Transmission Regulation, that the costs of local interconnections which are used by more than one customer are to be shared amongst the other customers using that interconnection. The Board is of the view that this interpretation is consistent with the policy objectives of this scheme.

The Board considers that, even if it were possible to support the AESO’s proposed broad interpretation of the effect of Subsection 16(4) as valid, the Board would have very significant concerns about the potential abuse by customers seeking to minimize their contribution costs that could result in the application of Article 9.8, as proposed. In that event, the Board would have required the AESO to devise a number of safeguards to ensure that the potential abuses identified by FIRM would not occur.

With respect to the submission of the AESO that its interpretation of Subsection 16(4) of the Regulation is supported by the Government’s Transmission Policy paper, the Board notes that the passage referenced by the AESO in its reply argument occurs within the context of a discussion of Generator System Contribution. However, the Board notes that the referenced section of the policy paper does not address the question of whether secondary users of previously constructed local facilities should trigger a re-designation of a customer cost to a system cost. In any event, the Board notes that the passage from the Transmission Policy referenced by the AESO merely describes the generic dividing line for system and customer costs for the purposes of the generator contribution policy.

In light of the above noted findings, the Board considers that Article 9.8 must be amended. Accordingly, the Board directs that, in its refiling, the AESO provide a revised version of
Article 9.8 based on the wording of the existing Tariff’s Article 9.8. The proposed revision should exclude current sub-Articles (a)(i) and (ii) as they are no longer relevant, given the investment formula approved by the Board.

In addition to the above, the Board notes that the AESO proposed to drop Article 9.8 (c) from the existing Tariff’s T&Cs on the basis of the AESO’s assessment that the administrative burden associated with contribution refunds was not expected to be sufficiently onerous to require the continuation of the $50,000 threshold.

The Board notes that no parties commented on the AESO’s proposal to eliminate the $50,000 threshold. The Board likewise has no objections. However, the Board also notes that AESO’s proposal to eliminate the $50,000 minimum refund threshold may have been premised on the Board’s adoption of Article 9.8 as applied-for by the AESO. The Board notes that the AESO’s proposed Article 9.8 provided for a straightforward transfer between existing customers (i.e. “the system”) and the customer originally paying a contribution in respect of local interconnection facilities. However, with the Board’s variance of the proposed AESO wording of Article 9.8, the Board considers that the administrative costs associated with arranging for the transfers of money between old and new customers served by an existing local connection may be more complex and onerous than initially contemplated by the AESO.

In light of the above, the Board considers that the AESO should have the option of reinstating a minimum contribution threshold if, in the AESO’s opinion, the administrative burden requires this. Accordingly, the Board hereby directs the AESO in its refiling to advise the Board as to whether the minimum contribution refund threshold as provided in the existing AESO Tariff’s Article 9.8 (c) should be reinstated and, if so, to amend its T&Cs accordingly.

6.1.6.6 Conditions for Customer Contribution Adjustments

Article 9.6 of the proposed T&Cs provides directions to the AESO for dealing with situations when changed circumstances result in changes in the estimated cost of an interconnection project cost as compared to the initial cost estimate provided to a customer.

The Board notes that no parties raised concerns with Article 9.6. The Board has also reviewed Article 9.6 and considers that it should be approved as filed.

6.1.6.7 Pre-Paid Operations and Maintenance Charge

Article 9.13 of the proposed T&Cs provides for a prepaid operations and maintenance (O&M) charge calculated as 12% of the customer-related costs of an interconnection to be applied to all new STS customers.

For all other AESO customers, including DTS customers, Article 9.13 also provides for a prepaid O&M charge to be levied. The charge is to be calculated as 12% of the cost of any interconnection facilities deemed to be in excess of the AESO Standard Facilities for the interconnection project.

The AESO considered that its proposal to apply a prepaid O&M charge to newly connecting STS customers is consistent with Subsection 16(1)(a) of the Transmission Regulation which requires newly connecting generators to pay all local interconnection costs for connecting to the transmission system. The AESO considered that as customer interconnections incur on-going
O&M costs beyond their initial capital costs, it would be appropriate to include a prepaid O&M charge to ensure that load customers do not pay costs related to generator interconnections.

Alpac was opposed to the adoption of the AESO’s proposed prepaid O&M charge to generators because, in its view, doing so would not be consistent with the Transmission Regulation and because it would create discrimination between existing and new generators. Alpac submitted that Subsection 30(a) of the Transmission Regulation must be interpreted such that all wires related costs are allocated to load customers. Additionally, it submitted that Subsections 30(b) and 16(1) of the Transmission Regulation would not support making generation unit owners responsible for on-going operations and maintenance costs. Alpac noted that Subsection 30(b) permitted three types of costs to be charged to owners of generating units:

1. interconnection costs,
2. a financial contribution towards system upgrades, and
3. location based losses charges.

Alpac submitted that the use of the specific wording in Subsection 16(1)(a) that “local interconnection costs” are “payable by an owner of a generating unit for connecting to the transmission system” does not support an interpretation making generating units financially responsible for the operation and ongoing maintenance of portions of the transmission system. Alpac also noted that the AESO had confirmed that while prepaid O&M charges were applied to generators under the vertically integrated regime existing in Alberta prior to 1996, this practice was not continued from 1996 on under the tariffs of the AESO’s predecessors (GRIDCO and EAL). Accordingly, Alpac submitted that re-instituting a prepaid O&M charge to generators after a decade’s absence would be unfair and would provide an unwarranted first-mover advantage for the generation unit owners who have developed projects since 1996.

While FIRM was supportive of a prepaid O&M charge, FIRM submitted that evidence presented during the Application proceeding did not support 12% as the appropriate level for the surcharge. In the absence of supporting evidence, FIRM submitted that the prepaid O&M surcharge should be set with regard to the ratios of “other expenses charges” to capital charges for the duplication avoidance tariff riders contained in the AESO’s current tariff. FIRM submitted that on the basis of its analysis, the prepaid O&M surcharge should increase from the AESO’s proposed level of 12% to 15.2% until such time as a more detailed review has been completed by the AESO.

The Board has established four considerations in its disposition of the AESO’s proposed prepaid O&M charge, namely:

- Whether the implementation of a prepaid O&M charge would be beneficial to the orderly evolution of the transmission system.
- Whether the application of a prepaid maintenance charge is consistent with provisions of the Transmission Regulation.
- To the extent that it is consistent with the Transmission Regulation, how should the amount of the charge applied to specific customers be determined.
- If a prepaid O&M charge is adopted, what is the appropriate amount of a prepaid O&M charge in the immediate term and/or in respect of future years.

The Board has considered each of these elements separately as they apply to STS customers and DTS customers.
STS Customers
With respect to the first question, the Board considers that the notion of a prepaid O&M charge is consistent with the goal of providing an appropriate economic signal to new customers considering an interconnection to the AIES. Accordingly, the Board considers that a prepaid O&M charge should be pursued to the extent that doing so is in compliance with legislation.

With respect to the second consideration, however, the Board considers the application of the AESO’s proposed prepaid O&M charge to STS customers to be problematic. The Board agrees with Alpac that Section 30 of the Transmission Regulation describes the types of costs that may be charged to generators. That section limits the recovery of costs from generators to:

- Local interconnection costs as set out in Section 16; and
- Financial contributions for transmission system losses (as further described in Section 22) and system upgrades (as further described in Section 17).

With regard to the foregoing list, the Board considers that the only manner in which the Board could conclude that a prepaid O&M cost could be applied to a generator is if the proposed charge could be treated as being part of the “local interconnection cost to connect its generating unit to the transmission system”. Applying ordinary provisions of statutory interpretation, the language in this provision clearly restricts the responsibility for generators to assume the costs necessary to connect to the transmission system. The language does not contemplate any ongoing costs beyond the initial connection costs. This is borne out by the inclusion of the phrase “costs to connect”.

Had the drafters of the legislation intended the owners of generating units to be responsible for ongoing costs to maintain the connection, they would have said so. Given this interpretation, the Board concludes that the AESO cannot convert an ongoing cost, such as operations and maintenance for the interconnection, to a capital cost by requiring the cost to be paid in advance. For this reason, the Board considers that the proposed Article 9.3(a) cannot be approved. Having determined that a prepaid O&M charge cannot be supported by the Transmission Regulation, there is no need to address the remaining considerations respecting STS customers.

Accordingly, the Board hereby directs that, in its refiling of the Application, the AESO shall redraft Article 9.3 so as to exclude in its entirety the Article 9.3(a) portion of the Article.

DTS Customers
As noted above, with respect to the Board’s finding respecting the first issue, the Board considers that the prepaid O&M charge may be beneficial from the standpoint of economic efficiency and from the standpoint of the desire to send appropriate economic siting and facility development signals through the contribution policy.

On the second issue, the Board considers that there is no restriction arising from either Subsection 30(a) or elsewhere in the Transmission Regulation that would preclude the use of the charge as it is applied to DTS customers.

With respect to the third question regarding the structure of the charge, the Board considers that specific improvements need to be implemented in conjunction with the AESO’s refiling. The Board is particularly concerned that, in applying the proposed DTS customer pre-paid O&M
charge only to the deemed “optional facility costs” of a new interconnection, the AESO appears to be implicitly assuming that the combined amount of the pre-paid O&M costs associated with the “non-optional” local interconnection facilities and the cost of the non-optional facilities themselves will fall below the level permitted under the maximum investment allowance. However, the Board considers that this should not be presumed, particularly in light of the adjustments to the maximum investment function ordered by the Board in Section 6.1.4 above.

While the Board considers that the prepaid O&M charge may be improved with further research, the Board considers that the adoption of a 12% surcharge as proposed by the AESO is a good starting point for the purposes of the 2006 Tariff.

Accordingly, the Board directs the AESO in its refiling Application to apply the 12% prepaid O&M surcharge such that:

- The surcharge will be determined separately for the optional and non-optional facilities;
- The portion of a DTS interconnection project’s prepaid O&M surcharge based on cost of the optional facilities will be fully charged out to the interconnecting DTS customer, consistent with the Board’s disposition of other optional facility costs; and,
- The portion of the prepaid O&M surcharge related to non-optional facilities is added to other non-optional facility costs and evaluated against the maximum investment function to determine the amount of customer contribution that may be required in respect of the standard facility portion, if any.

While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application.

6.2 Generator System Contribution

Subsection 17(2) of the Transmission Regulation requires the AESO to collect, in its tariff, a system contribution charge of $10,000/MW from the owners of new generators for system upgrades to existing transmission facilities required as a result of a generator’s entry on to the AIES grid. This subsection further directs the AESO to collect a system contribution charge of no more than $40,000/MW from the owners of new generators who locate in areas of the transmission system where generation exceeds load, with the amount to be based on the location of the new generating unit relative to the load.

Subsection 17(4) of the Transmission Regulation directs the AESO to include in its tariff, a provision for the refund to the owner of a generating unit who paid system contribution charges pursuant to Section 17. The refund must be received over a period of 10 years from the date it was paid unless the operation of the generating unit failed to meet satisfactory performance standards as set forth in rules to be developed by the AESO pursuant to Subsection 17(5).

In its application, the AESO proposed to refund generator system contributions by way of 9 equal payments spread out over the 10 year period. The AESO explained that its suggested proposal was created to allow for the event that an owner of a generator might experience
circumstances beyond its control during one year of the 10 year period, thus not satisfying the AESO’s rules for satisfactory operation for that year. The AESO reasoned that the owner of the generator should still have an opportunity to collect the full amount of the system contribution it made, despite having 1 substandard year during the 10 year period.

The AESO noted the system contribution must be paid before construction and must be refunded within ten years of payment subject to satisfactory performance. Since satisfactory performance can only begin after construction is complete, and since construction of both the generating unit and interconnection facilities takes time, Article 9.10 of its Terms and Conditions provided for the refund of the system contribution in fewer than nine equal annual amounts, based on the number of years after the commercial operation date of the generator and the ninth year after payment. However, to ensure that the interconnection proceeded, if the commercial operation date was later than five years after payment of the system contribution, one-fifth of the contribution would be forfeited for each additional year the commercial operation date was delayed beyond five years. If the commercial operation date did not occur within ten years after the system contribution was paid, the whole contribution would be forfeited. The AESO also proposed that no interest would be paid on the contributions. Rather, they would be treated as no-cost capital with any interest earned used to reduce overall AESO interest expense.\(^\text{102}\) The AESO noted\(^\text{103}\) that it would be developing the rules for performance measurement outside the ambit of this proceeding, given its understanding that Board approval of these rules is not required under Subsection 17(5).

TAU argued that allowing the AESO to implement rules concerning a generator’s minimum operation standards might unduly influence the energy market and would be contrary to the intent of the Transmission Regulation. TAU considered that the AESO’s role should be to facilitate an open and competitive energy market but not to influence the manner in which the energy market operates.

FIRM’s position in the proceeding was that the AESO should structure the timing of the refund of the system contributions over the 10 year period in a manner which would motivate the owners of generators to meet the AESO’s performance standards for operation over the entire period, especially during the initial portion of the refund period, when the impact on the AESO’s revenue requirement caused by the inclusion of these new generators would be the highest. To achieve this goal, FIRM considered that the system contribution refund amounts should increase year by year over the 10 year refund period such that the lowest percentage of the refund would be provided in the first year and the highest percentage would be available in the last year. FIRM considered that this approach appropriately reflected the front end nature of the expenditures on system transmission facilities built for the benefit of the owners of generators. FIRM indicated that its approach could be combined with the AESO’s recommendation to withhold 1/5 of the system contribution refund for each year after the 5th year in which a generator was still not interconnected.

With respect to TAU’s concern that the imposition of rules concerning minimum generator output by the AESO may unduly influence the market, the Board notes that Subsection 17(5) of the Transmission Regulation clearly states that the AESO “must make rules to be used to assess the satisfactory performance of a generating unit by generating unit type”. The Board notes that

\(^{102}\) Application, Section 6, page 26
\(^{103}\) Application, Section 6, page 27
the AESO has held, and has stated its intention to hold in the future, additional workshops around the development of these rules, and further that the AESO has acknowledged that it will utilize the input it has received in this proceeding in the development of these rules.

While the Board does not wish to discourage the AESO’s stated intention to consult with stakeholders in the development of these performance rules, the Board expects that the AESO, in developing its rules, will adhere to reasonable commercial principles in their creation regardless of the input received during the consultation process. The Board notes that the AESO has jurisdiction over the development of the rules. However, the Board retains jurisdiction over the evaluation of such rules in the event of a complaint further to Section 25 of the EUA. As these rules have not been developed, the Board will not comment further on the concerns expressed by TAU and expects TAU to take this matter up with the AESO as part of the AESO’s consultation process.

With respect to FIRM’s proposition that the system contribution refunds increase in amount over the 10 year period, the Board considers this option has considerable merit.

The Board is concerned that AESO customers should not face undue risks that system investments that may have been significantly predicated on the facilitation of an open and competitive generation marketplace should become stranded at the cost of DTS customers as a result of a generator owner’s failure to fulfill its commitments. The Board considers that the back-end loading of refunds reflects the fact that the AESO is required to place considerable reliance on the forecasts of generator owners in devising its long term transmission plans. As such, the Board considers it fair, in light of the generator owner’s ability to obtain a full or partial refund of the system contribution costs that it paid, to place some onus on generator owners to ensure that capacity built on their behalf is appropriately available and satisfactorily utilized.

The Board notes that load customers bear the risk of additional capital and interest costs in the event that a generator owner does not meet the commercial operation date for delivery of energy to the transmission assets that the owner requires from the AESO and for which date the AESO implemented its transmission system upgrade plans.

Having considered all of the above, the Board hereby directs the AESO to provide an amended Article 9.10 of the Terms and Conditions in its refiling application in accordance with the following parameters:

1. Payment of all of the charges pursuant to Subsection 17(2) shall be made prior to the date of construction. The Board recognizes that Subsection 17(3)(e) only requires the owner of a generator to pay the charges owing under Subsection 17 (2)(b) before commencement of construction of the local interconnection facility. However, the Board considers that prepayment of all costs, either customer contribution or system contribution, should be paid prior to the start of the commencement of activities related to the construction of any new transmission facilities necessary to provide the requested service. This will benefit the public interest by providing the maximum level of security from the outset. This will also encourage new generators to achieve commercial operation at the earliest time in order to realize their refunds, and will also be in the interests of all Albertans as they seek to realize the benefits of such generation as soon as it can reach commercial operation.
2. Any refund paid to a generating owner pursuant to Subsection 17 (4) shall be paid out no later than 10 years following the date of original payment but shall not be due and owing until after the commercial operation date for the generating unit has been achieved provided that the commercial operation date is before the expiration of the 10 years. This will, of necessity compress the refund period to a remaining period of less than 10 years in most, if not all, circumstances. For purposes of clarity, commercial operation date means the date agreed to by the AESO and the generator owner when the plant requires the transmission assets requested for delivery of energy to the AIES.

For example, assume that a charge is paid to the AESO by the generator owner on January 1, 2006 pursuant to Subsection 17 (2). In accordance with Subsection 17 (4)(a) of the Transmission Regulation, and assuming satisfactory performance, the generator owner would be entitled to receive a full refund of its payment by no later than December 31, 2015. However, if the commercial operation date is January 1, 2008, the AESO will only have 8 rather than 10 years to pay out the refund.

3. In the event that a generator owner does not commence the delivery of energy at the levels agreed with the AESO at the time that the generator contributions were provided to the AESO by the commercial operation date for any reason whatsoever, then for each year or portion thereof that the date is delayed, the refund for that year or portion thereof will be forfeited.

Again, in consideration of the example above, in the event that the commercial operating date is not January 1, 2008 as originally provided to the AESO but is January 1, 2009, then the AESO shall deem that entire period to be one in which the generator owner failed to meet satisfactory performance standards and as such, the AESO will be entitled to retain that portion of the refund that otherwise would have been payable that year. The overall schedule over which the refund is to be paid will not change.

4. Once commercial operation of the generating unit has commenced, in the event that a generator owner fails to meet satisfactory performance standards, any refund will be forfeited for that period.

5. The refund amount shall be structured in a backend loaded manner over the refund period such that 25% of the total refund shall be paid out in equal payments per year over the first half of the refund period and 75% shall be paid out in equal payments per year over the last half of the remaining period.

Using the example outlined above, in the event that a generator owner becomes eligible for a refund as of January 1, 2008 (the commercial operation date) and again assuming that the payment period ends December 31, 2015, then, for the years 2008 to 2011, 25% of the total eligible refund is available to be refunded in 4 equal payments while for the years 2012 to 2015, 75% of the total eligible refund is available to be refunded in 4 equal payments.

6. The AESO shall apply any forfeited refund amounts to a deferral account and any balances in that account shall be considered a revenue offset to its revenue requirement in a subsequent GTA.
7. No interest shall be payable by the AESO to a generator owner on any refund amounts.

6.3 Contribution Policy Next Steps

6.3.1 Contribution Policy Implementation Timing

The Board notes that the Application proposed that the Tariff should come into effect on January 1, 2006 which is consistent with the legislative timing required by Subsection 31(3) of the Transmission Regulation.

6.3.2 Disco/AESO Contribution Policy Harmonization

The Board notes that a concern about the need to advance the harmonization of the contribution policies of the AESO and distribution utilities has been discussed in several parts of this decision. In light of this concern, the Board considers that it would be beneficial for the AESO to assume a leadership role towards achieving greater harmonization and coordination.

Accordingly, the Board hereby directs the AESO, in conjunction with the distribution utilities and such other stakeholders the AESO would consider to have an interest, to develop a proposal for harmonization of these contribution policies and to present the results at its next GTA.

Although the Board considers that the ultimate terms of reference for the harmonization initiative should be established by the AESO and participating stakeholders, the Board considers that it would be beneficial for the harmonization process to, at minimum, address the following issues:

- The development of a common definition of standard POD facilities as between Disco’s and AESO (TFO) connected customers.
- Consideration of whether it is appropriate to establish defined “cutoffs” such as a maximum MVA capacity for the consideration of the interconnection of a new customer to a Disco and/or a minimum threshold for the consideration of the interconnection of a new customer to a TFO system.
- Consideration as to whether it is feasible or appropriate to adopt a common form for a cost based maximum investment function (i.e. a standard formula that would provide a greater cost allowance for the purposes the Disco’s and AESO’s respective investment policies with increases in the capacity of the interconnection.

In conjunction with the above, the Board hereby also directs the AESO to provide a progress report on its contribution policy harmonization efforts in conjunction with its 2007 Tariff Application.

6.4 TransCanada Standard Interconnection Facilities Complaint

On September 20, 2004, TCE filed a complaint with the Board pursuant to Section 25(1)(b) of the EUA in respect of the manner in which the AESO’s current contribution policy was applied in respect of interconnection facilities built for a TCE gas storage facility near Edson, Alberta (the Edson facility). In follow up correspondence to the Board dated February 17, 2004, TCE further advised that it would be prepared to have its complaint matter addressed in the context of the 2005/2006 tariff proceeding.

Pursuant to Section 25 of the EUA, the Board, on receipt of a complaint under this provision, may, by giving written notice to the party making the complaint, investigate a complaint, decline
to investigate the complaint, hold a hearing or terminate an investigation or hearing provided the
grounds for termination as set forth in Subsections 25(4) (a) through (d) of the Act are satisfied.

In order for the Board to make a determination respecting this complaint, the Board must,
pursuant to Subsection 25 (6) of the Act, determine the justness and reasonableness of the AESO
fee complained of. In order to do so, the Board must make a determination of the justness and
reasonableness of the current tariff policy and the application of that policy to the Edson facility.
As the subject matter of this hearing was with respect to the proposed tariff policy, the Board
does not consider it advisable to address this complaint within this Application proceeding but
will consider the complaint in a separate proceeding.

7 TERMS AND CONDITIONS – OTHER

7.1 System Access Applications

The AESO proposed to amend Article 5 (previously 7) of the T&Cs to accord with the
AESO’s revised interconnection process. The AESO explained the new process has been
established through stakeholder collaboration that included representatives from the AESO, the
EUB, ENMAX, EPCOR, FortisAlberta, ATCO, AltaLink, VisionQuest, Canadian Natural
Resources Limited, and EnCana. The AESO stated implementation of the transmission
interconnection process is continuing to be developed among those parties.

The AESO stated the new single-stage process would allow for a more active presence by the
transmission facilities owner (TFO) and a more direct working relationship between service
providers and customers, which is intended to streamline system access applications. Although
the AESO will retain oversight of all transmission interconnections, it will no longer perform
each of the day-to-day tasks related to such projects. For example, payment of customer
contributions will normally be made directly by the customer to the TFO, although determination
and administration of customer contributions will remain with the AESO.

As part of the new interconnection process, Article 5 includes the following three revisions to the
level and applicability of system application fees. The existing fee structure was established
through the AESO’s 2002 Negotiated Settlement and was intended to create a manageable
interconnection queue by introducing fees large enough to discourage customers who did not
seriously intend to proceed with interconnection.

The AESO proposed to revise three aspects of the system application fee.

a. System application fees are proposed to be simplified and reduced. The current two-
stage application fee has been revised to a single charge in accordance with the new
single-stage interconnection process. Table 6.3.1 provides a comparison of proposed
and current fees.
Alberta Electric System Operator (AESO)

2005/2006 General Tariff Application

August 28, 2005
ALBERTA ENERGY AND UTILITIES BOARD
Decision 2005-096: Alberta Electric System Operator (AESO)
2005/2006 General Tariff Application
Application No. 1363012

August 28, 2005

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Web site: www.eub.gov.ab.ca
• Rider E would address only the calibration factor related to transmission system losses and would apply to Rate STS as well as all opportunity rates (DOS 7 Minutes, DOS Term, EOS, and IOS).

• Rider E’s purpose would be “...to adjust loss factors to ensure that the actual cost of losses is reasonably recovered through charges and credits on an annual basis” in accordance with Subsection 21(1) of the Transmission Regulation.

• Rider E would be determined prior to the beginning of each calendar quarter, and would be set at a level that, if applied for the remainder of the calendar year, would result in the full recovery of the actual cost of transmission line losses by the end of the calendar year.

• Rider E would be applied as a calibration factor percentage based on the preceding which would be added to or subtracted from all location-specific loss factors for generators and all opportunity services.

• Rider E would apply on a prospective basis only in accordance with Subsection 21(2) of the Transmission Regulation. However, an annual reconciliation would be filed with the EUB for information purposes only.

• As Rider E will be set in advance based on a forecast year-end balance, there will likely remain some small difference between the anticipated and actual cost of transmission line losses at the end of the year. Any year-end balance will be included in the next year’s Rider E in accordance with Subsection 21(2) of the Transmission Regulation.

Rider E should primarily address variances from forecast of losses volumes. Variances from forecast of pool price should not require Rider E recovery or refund as both the cost of transmission system losses and the recovery (through a percentage of pool price) varies directly with pool price. Establishing Rider E with a purpose of achieving a zero balance at year-end should avoid any seasonal variations that could arise if the rider’s purpose was to achieve a zero balance at the end of the following quarter.

In reply, the AESO noted that no party had commented upon this Rider proposal and suggested it should be approved as filed. The Board agrees and it is approved as filed.

6 TERMS AND CONDITIONS – CONTRIBUTION POLICY

6.1 Customer Contribution Policy

The AESO proposed a number of major revisions to the customer contribution policy in the 2005-2006 Application.

6.1.1 High Level Policy Principles

The AESO submitted in the Application that the current contribution policy approved in Decision 2001-6 was devised with regard to four major principles, namely:

• The desire to impose an economic siting discipline on customers;
• Consistency with the “postage stamp” principle;
• Harmonization with the contribution policies of distribution facility owners (Discos); and
• Consistent application of the policy to all load customers.
The AESO submitted that the refinements to the contribution policy proposed in the Application were necessary to achieve these principles and to reduce the need for discretionary classification of project costs.

The Board will evaluate the AESO’s proposed changes to the contribution policy in light of these policy principles in the sections that follow. In addition, the Board will also consider other factors in assessing the appropriateness of the AESO’s proposal that have arisen since Decision 2001-6 was released. In particular, the Board will be mindful of the impact that the Transmission Regulation may have on these principles.

Provision of Economic Signal(s)
The Board notes that Decision 2002-082, in respect of ATCO Electric’s (AE’s) 2002 Investment and Contribution Policy, extensively investigated the principles underlying electric utility contribution/investment policies. In turn, that Decision quoted Decision 2000-1 as follows in order to set out certain basic principles for its disposition of the AE contribution policy:

The Board considers that customer contributions are suitable in circumstances where service to a customer may impose costs on other customers for which they should not be responsible. An appropriate contribution policy therefore provides a suitable balance to an unlimited obligation to serve by imposing economic discipline on siting decisions. It transfers the economic burden of connection of new customers from the utility and its existing customers to the new customer. In other words, it exerts some of the discipline of the utility’s economics on the economic decision-making of the customer. The Board considers that customer contributions should relate only to the local connection costs of the system expansion. The deep system costs of expansion are properly the responsibility of all customers, form part of the utility’s revenue requirement and should be recovered from all customers through rates.

The Board’s views on the underlying purpose of a contribution policy have not changed since Decision 2002-082 was issued. As such, it remains important to the Board that the AESO’s contribution policy should continue to exert an economic discipline on siting decisions by sending price signals reflective of the AESO’s economics to an interconnecting customer.

The Board also notes the following finding reflected in Decision 2002-082 (originally derived from Decision 2001-38):

The Board considers that these same observations apply at the distribution level in the case of AE’s investment policy. Achieving a suitable balance to an unlimited obligation to service does not necessarily mean that investment levels should be set as high as possible without placing undue upward pressure on rates. For example, if a technological breakthrough significantly reduced the cost of connecting new customers, it may be appropriate to reduce the level of investment to maintain intergenerational equity. In such circumstances, all generations of customers would benefit from investment toward the same functionality of service, and all customers would benefit from the eventual downward pressure on rates.

Conversely, if the Board were persuaded that it was appropriate to adopt a new standard of construction (for example, underground instead of overhead construction), the Board might approve a significant increase in the level of investment, which would eventually result in upward pressure on rates for all customers.
The Board considers that the appropriate maximum level of investment could be affected by factors such as technological advancements and changes in standards of construction. Absent such factors, the Board would generally expect that maintaining a suitable balance to an unlimited obligation to serve would result in investment levels increasing with inflationary pressures, offset by productivity and technological improvements. This would result in different generations of customers benefiting from investment toward the same functionality of service, and would also result in approximately the same economic discipline on different generations of customers.

The Board notes that, while the above noted passage was taken from a decision issued by the Board in respect of ATCO Electric’s contribution investment policy, the principles described therein also apply to the AESO. Accordingly, the Board considers that three aspects of the above noted passage are relevant in considering the disposition of the AESO’s proposed contribution policy. These aspects are:

- Establishing a maximum investment allowance;
- Establishing standards for functionality and service characteristics; and
- Recognizing the changing nature of the standards for functionality and service.

The Board notes that the above referenced passage does not support a proposition that investment allowances should be set at the maximum amount of incremental revenues generated by the interconnection of a new customer. Rather, the Board has identified its concern that such a proposal may place undue upward pressure on rates. The Board continues to be concerned that setting investment allowances at a level significantly above the expected cost of an interconnection would be inflationary. In particular, the Board is concerned that an excessive investment allowance could provide incentives for customers to pursue higher standards of connection facilities than required, largely on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance. Accordingly, the Board considers that the incremental revenue generated by an interconnection should only be used as an upper bound but should not be the primary driver of the investment formula. The Board will provide further elaboration on these matters in its discussion of the AESO’s proposed Maximum Investment formula, found in Section 6.1.4 of this Decision.

The Board also notes that the passage above from Decision 2002-082 focuses on consideration of the functionality and service characteristics provided by the interconnection facilities rather than on the financial aspects as the principal driver of the contribution policy. Given this focus, investment allowances should be set with regard to the anticipated cost of establishing an interconnection to the AIES (Alberta Interconnected Electrical System) reflecting acceptable standards of functionality/service established by the AESO.

The above referenced passage from Decision 2002-082 also recognizes that the standards of functionality and service characteristics may change over time. The Board discusses this issue further in Section 6.1.3.1 of the Decision respecting the AESO’s proposed definition of “AESO Standard Service”.

**Consistency with Postage Stamp Principle**
The AESO suggested in the Application that certain aspects of its proposed contribution policy would bring the policy in closer alignment with the “postage stamp principle” outlined in Section 30(3) of the EUA which reads as follows:
s. 30 (3) The rates set out in the tariff

(a) shall not be different for owners of electric distribution systems, customers who are industrial systems or a person who has made an arrangement under section 101(2) as a result of the location of those systems or persons on the transmission system, and

(b) are not unjust or unreasonable simply because they comply with clause (a).

The Board notes that the wording of Subsection 30(3) substantially preserves the postage stamp rates provision from Section 27 of the version of the EUA in effect prior to June 2003, which was worded as follows:

s. 27(2) The rates set out in the tariff

(a) must reflect the prudent costs that are reasonably attributable to each class of system access service provided by the Transmission Administrator, and

(b) must not be different for owners of electric distribution systems as a result of the location of those systems on the transmission system.

(3) Rates are not unjust or unreasonable simply because they are prepared taking into account subsection (2)(b).

The Board notes that previous Board Decisions in respect of the AESO's predecessor, EAL, including Decision 2000-1 and Decision 2001-6 examined the manner in which the postage stamp principle should coexist with the use of contribution policies to provide appropriate economic siting signals. In particular, the Board determined in Decision 2001-6 that because the contribution policy proposed by EAL did not have the effect of making the location of an electric distribution system on the transmission system or the geographic location of a POD within Alberta a consideration in how the contribution policy was applied, the contribution policy of EAL complied with the postage stamp requirements of Subsection 27(2)(b). Accordingly, the Board considers that the contribution policy of the AESO's existing tariff may also be judged to align with the postage stamp principle as described in Subsection 30(3). It did not need to be altered to be brought into compliance.

**Harmonization of the AESO Contribution Policy with Contribution Policies of Discos**

The AESO advised that it is seeking to harmonize its contribution policy with those of the other regulated distribution companies in Alberta. The AESO submitted that the form of the maximum local investment function proposed in the Application would provide a better harmonization with the similarly-structured load-based investment policies of most distribution facility owners (Discos). By using an average unit investment allowance that varies with contract term, the maximum local investment allows customers to lower the customer contribution required by contracting for a longer DTS contract term.
The AESO indicated that it hoped its redesign of the maximum investment formula would ensure that approximately 80% of customer interconnection projects would be fully covered by the selected maximum investment limit while 20% of projects would only be partially covered. The AESO noted this “80/20 criteria” was initially adopted in order to preserve intergenerational equity relative to the customer contributions required during the vertically integrated regime that existed prior to the unbundling of the Alberta electricity system that occurred in 2001. The AESO noted that the “80/20 criteria” was accepted by the Board in Decision 2001-6. 69

The Board notes that the rationale for seeking to harmonize the contribution policies of the AESO with the Discos was evaluated by the Board in Decision 2001-6. As noted in Decision 2001-6, the harmonization issues under consideration in that proceeding primarily related to the following aspects of the contribution policy:

- Ensuring the appropriate harmonization between the contribution policies of the distribution utilities and the AESO’s predecessor;
- Ensuring that the contribution policy did not disturb proper planning; and
- Understanding how the customer contribution policy affects a customer’s decision to choose to become a “direct” transmission-connected customer versus a distribution-connected or isolated generation customer.

The Board considers that while progress has been made in relation to the last of the harmonization goals noted above, additional improvements could be made. In particular, and as further discussed in Section 6.3.2 of this Decision, the Board considers that the primary focus on Disco/AESCO harmonization efforts should be directed towards harmonizing the definitions of “standard facilities” and “optional facilities”.

Application of Supply Contribution Principles to Load Contribution Policy
The Board notes that the load customer contribution policy proposed in the Application parallels several aspects of the contribution policy for new interconnecting generators as outlined in the Transmission Regulation. The major components of the generator contribution policy are described in Sections 16 and 17 of the Transmission Regulation.

Through information requests, the Board sought to clarify the extent to which consistency is required between aspects of the Transmission Regulation’s generator contribution policy and the load contribution policy proposed by the AESO for the Application. The Board notes that, in one of its responses 70, the AESO indicated that Subsection 16(4) of the Transmission Regulation had played some part in the formulation of the load policy, namely, the determination of whether a cost arising from an interconnection should be designated as a “system” or a “customer” cost.

The AESO noted that whereas Subsections 16(1), 16(2), and 16(3) all refer specifically to the interconnection by the “owner of a generating unit” to the transmission system, Subsection 16(4) of the Transmission Regulation uses the terminology “another person”. The AESO thus considered that the use of “another person” rather than “owner of a generating unit” was intended to imply general application of Subsection 16(4) to both generators and loads.

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69 Decision 2001-6, page 70
70 BR-AESO-017

46 - EUB Decision 2005-096 (August 28, 2005)
The AESO further noted that, in general, facilities constructed for the same purpose should be classified the same regardless of whether the interconnection is for a generator or a load customer. In the AESO's view, to do otherwise would be problematic for dual-use interconnections (serving both a generator and a load customer). The AESO did not consider that any other aspects of the Transmission Regulation had influenced its proposed contribution policy for load customers.\footnote{BR-AESO-017}

The Board has considered the provisions in Section 16 of the Transmission Regulation and agrees with the AESO that the reference to "another person" rather than "the owner of a generating unit" in Subsection 16(4) of the Transmission Regulation may be interpreted as a reflection of the Government's intent to apply this provision to any type of customer that wishes to make use of previously constructed interconnection facilities and is not intended to be restricted to generators alone. However, as noted by the AESO, the more specific references to "a generating unit" in the other subsections of Sections 16 and 17 of the Transmission Regulation have the effect of making these requirements mandatory only in respect of interconnecting generating units. Therefore, while the Board is not precluded from adopting the AESO's proposal to devise a load customer contribution policy that largely parallels the design principles for generator contributions outlined in the Transmission Regulation, the Transmission Regulation does not require the AESO to devise a parallel load customer contribution policy. Whether it is in the public interest to do so is a separate issue that must be determined by the Board.

The Board considers that the fundamental difference between the load customer contribution in the AESO’s current tariff and the generator contribution policy relates to the manner in which "system-related" and "customer-related" costs are determined. The existing contribution policy is essentially top-down in nature in the sense that the baseline for the identification of system-related and customer-related costs arises from an evaluation of the facilities currently available or contemplated for addition over the next five years in relation to the AESO’s long term system plan. Under this approach, any additional facilities and costs arising from a new customer’s interconnection are identified as customer-related costs and are charged to the existing customer. In contrast, the generator contribution policy described in the Transmission Regulation may be considered more of a bottom-up approach, in the sense that the generator’s local interconnection facility costs are determined first and deemed to be the customer-related costs associated with the interconnection. Any further residual incremental system enhancement or upgrade costs not fitting the definition of a local interconnection facility cost are deemed to be system-related, and thus excluded from the contribution policy.

As further described in the Board’s discussion of the designation of system and customer costs in Section 6.1.2 of this Decision, the Board does not, in general, consider that the generator contribution policy principles outlined in the Transmission Regulation should necessarily be used as the model for establishing the load customer contribution policy unless doing so is supportable under generally accepted principles of rate design.

6.1.2 Designation of System-Related Costs

The Board notes that the first step in the application of any contribution/investment policy is to classify costs as either system-related or customer-related.
The mechanism to classify costs as system-related or customer-related was set out in Article 9.2 of the existing AESO Tariff’s Terms and Conditions. Article 9.2 reflects the framework established by the Board in Decision 2001-6.

Under Article 9.2, the determination of whether a proposed interconnection project would be classified as system-related or customer-related depended on whether the proposed project was radial to the existing transmission system. If a proposed interconnection was radial, new interconnection facility costs were generally designated as customer costs. Alternatively, if all or a portion of a new interconnection project completed a looped configuration in conjunction either with existing transmission system facilities or in conjunction with system upgrades expected to be built within the next 5 years, the looped portion of a new interconnection project was deemed to be a system-related cost. Article 9.2 also allowed for the customer to pay for the cost of advancing any portions to be looped within the subsequent 5 year period.

Article 9.3 of the proposed T&Cs in the Application establishes the proposed methodology to designate system and customer-related costs. Although the AESO proposes to preserve the looped vs radial criteria it had established in Article 9.2 of the existing T&Cs, the looped vs radial designation will no longer be the primary determinant of whether a cost was to be designated as system or customer-related. In its place, the AESO has proposed the additional Article 9.3(a), which concentrates on defining the specific types of facilities within a new radial interconnection project that the AESO considers to be customer-related. In conjunction with its proposed focus on typical local interconnection facilities as the basis for identifying customer-related costs, the AESO has also proposed to designate any enhancements to the existing transmission system that may arise as a result of a new customer interconnection to be, by definition, system-related for the purposes of the contribution policy.

The AESO contends that its revised criteria for designating system-related and customer-related costs are necessary because the existing process for designating costs may tend to be unpredictable for customers. In particular, the AESO noted that because the AESO exercises some discretion in the case of enhancements, such as protection upgrades, it is possible under the existing T&Cs to designate such costs as either system or customer costs, depending on the AESO’s determination as to who benefits from the interconnection upgrade. The AESO provided a conceptual illustration of three basic approaches to the classification of system and customer costs in Figure 6.1.1 of the Application. The AESO noted that, while each scenario always classifies local connection costs as customer-related and classifies bulk system costs as system-related, the classification of system enhancements varied between the three alternatives. Of the three alternatives described by Figure 6.1.1, the AESO chose “Alternative 1” (all system enhancements designated as system costs) on the basis that the chosen alternative would provide a high level of predictability and would provide consistency in the treatment of load and generator interconnection projects.

The AESO’s proposal to treat system enhancements as system costs for the purposes of the contribution policy was supported by ATCO Electric. Conversely, FIRM opposed the automatic designation of enhancements as system costs.

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72 Application, Section 6, page 2
73 Application Section 6, p. 3 of 42
While desirable, the Board does not consider the goal of trying to achieve greater consistency between the generator and load customer contribution policies to be the most important public interest consideration. Accordingly, the Board is not persuaded that consistency with the generator contribution policy should, in and of itself, lead the Board to endorse the AESO’s proposed Alternative 1 in which all costs not specifically identifiable as a local interconnection cost should be deemed as system cost for contribution policy purposes.

The Board has difficulty accepting the proposition that decision making as to whether a system enhancement should be designated as a system or a customer cost should be problematic for the AESO. The Board notes that the radial vs looped framework currently in place in the T&Cs was proposed in part because it provided enhanced objectivity and predictability from a customer perspective.74

The Board also notes that the AESO has an explicit obligation under Subsection 4(2) of the Transmission Regulation to identify all transmission facility projects which the AESO proposes to initiate through a needs application within 5 years from the release of each update of its long term transmission system plan. Additionally, in respect of each project so identified, the AESO is required to provide the anticipated implementation schedule for the project. The Board considers that since detailed information must now be provided as required in Subsection 4(2), the AESO should be able to objectively assess whether a cost arising from a new interconnection warrants system or customer cost treatment.

With respect to the request of AE that the Board should provide clear directions respecting the classification of system and customer costs, the Board considers that the AESO should approach any situation in which there may be “shades of grey” in this designation exercise, with the position that a debatable interconnection project cost should be presumed initially to be customer-related unless clearly demonstrated otherwise.

The Board does not wish to take away the AESO’s discretion under Article 9.11 of its proposed T&Cs to deem costs normally designated as customer costs to be system-related costs in appropriate circumstances. The Board, however, considers that a general stance that system enhancement costs are customer costs unless demonstrated otherwise is consistent with the expectation that the AESO adopt a more proactive stance in respect of its overall system planning and transmission system upgrade responsibilities, as detailed in the Transmission Regulation.

6.1.3 “Standard” and “Optional” Interconnection Facilities

6.1.3.1 AESO Standard Service Definition

The T&Cs submitted with the Application include a proposed definition of the facilities that the AESO considers to be the standard facilities that it expects to provide for a new interconnection project. The definition of AESO Standard Facilities from Article 1 of the proposed T&Cs is as follows:

“AESO Standard Facilities” mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection.

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74 Decision 2001-6, p. 3 and p. 62
The AESO noted in its Argument that the inclusion of a definition of standard facilities in the Tariff was intended to provide clarity and transparency to a long-standing practice.\textsuperscript{75}

A number of parties addressed the definition of standard facilities in argument, including ATCO Electric, TCE, the Cities of Red Deer and Lethbridge and the FIRM Group.

TCE was particularly active respecting this issue, and proposed to define standard service as follows (TCE wording italicized to illustrate their proposed changes):

"AESCO Standard Facilities" mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of two lines of transmission circuit and two transformers to supply an individual POD for peak loads at or above 15 MVA and to generally consist of a single radial transmission circuit and a single transformer to supply an individual POD for peak loads below 15 MVA.

For reasons further described below, the Board has determined that the definition of "AESCO Standard Facilities" as set out in the T&Cs of the Application should be approved as filed by the AESO. The Board has addressed the views of the other parties below.

Reliability Obligations Required by Legislation
The Board notes that the Transmission Regulation has imposed additional obligations on the AESO to ensure that its reliability standards meet or exceed generally accepted North American reliability standards. The AESO's obligations in respect of reliability standards are set out in Part 2 of the Transmission Regulation, reproduced in part below:

8(1) In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must

(a) plan a transmission system that satisfies reliability standards, unless the ISO decides that to do so would not provide for a safe, reliable or efficient transmission system;

(b) ensure that transmission facilities adhere to reliability standards;

(c) monitor and ensure overall reliability of the interconnected electric system;

(d) comply with directives of the Board;

...  

(2) A decision by the ISO under subsection (1)(a) that a reliability standard would not be safe, reliable or efficient must be filed by the ISO with the Board for approval.

\textsuperscript{75} AESO Argument, p. 47 of 58

50 • EUB Decision 2005-096 (August 28, 2005)
The phrase “reliability standards” as referenced in Section 8 of the Transmission Regulation is defined in Subsection 1(1)(e) of the regulation as follows:

1(1)(e) “reliability standards” means the reliability standards agreements, criteria and directives of the Western Electric Coordinating Council and the North American Reliability Council, or their successor organizations, and reliability standards, agreements, criteria or directives of any similar entity recognized by the ISO;

The above referenced passages of the Transmission Regulation mandate the AESO to adhere to reliability standards that meet or exceed standards adopted by the North American Reliability Council (NERC) and the Western Electric Coordinating Council (WECC). While the Transmission Regulation provides some discretion to the AESO to deviate from specific elements of either the NERC or WECC standards, the AESO faces a reverse onus requirement to prove that compliance with a particular aspect of the NERC and WECC standards would not be safe, reliable or efficient in the Alberta context.

The AESO submitted that it adopted both the NERC and WECC Reliability Criteria as the basis for its own Reliability Criteria document. The Board notes that no evidence was provided during the Application proceeding to suggest that the AESO Reliability Criteria did not reflect the NERC and WECC Reliability Criteria to the extent required by the Transmission Regulation. As the AESO has not made any application pursuant to Subsection 8(2) of the Transmission Regulation seeking relief from the reliability standards, the Board considers that the obligation on the AESO to maintain these standards remains fully intact.

The Board notes that a comprehensive update to the AESO reliability standards was prepared by the AESO (AESO Reliability Criteria) and was circulated for stakeholder comment. The AESO’s Reliability Criteria document was filed in this proceeding by the AESO in response to an information request. In addition, a matrix document containing stakeholder comments on the AESO’s Reliability Criteria and the AESO’s responses to these comments was also filed in the Application proceeding.

The Board finds that the Point of Delivery (POD) Criteria described in Section 4.5 of the AESO Reliability Criteria document reflects the WECC’s determination within its Reliability Criteria that interconnection facilities based on a single radial circuit and single transformer are acceptable in relation to WECC’s standards. Further, it is also notable that the Section 4.5 POD Criteria expressly indicate that there is a risk of firm and opportunity load having to be shed in the event of an outage of the radial interconnection elements. Accordingly, the Board considers that AESO customers contemplating the interconnection of a new load will be aware of the potential for electric service disruption if they choose to rely solely on the facilities described by the POD Criteria.

The Board notes that the AESO indicated in its matrix that distribution customers and industrials would be treated the same. However, the Board notes that it might be argued that, if a multi-customer POD waiver were to be granted to distribution utilities with the result that distribution utilities could obtain system cost treatment for most or all of the costs of a second
transformer/second line while an industrial customer could not, this would constitute undue discrimination. The Board considers this concern to be valid. As such, this concern contributed to the Board’s decision to disallow the AESO’s multiple customer POD contribution waiver, as further discussed in Section 6.1.5 of the Decision.

**Economic Rationale for AESO Standard Facilities Definition**
The Board notes that certain parties suggested that POD service standards should be higher than a single line/single transformer standard and therefore advocated the adoption of a higher standard on the basis that the AESO has a duty to ensure that an equal quality of service is provided to all customers.

The Board notes that it was readily acknowledged by the AESO in the course of the proceeding that the adoption of one-line/one-transformer as the normal standard would not provide a minimally acceptable level of service for some customers. That is, the AESO has made it clear that it accepts that some customers would never consider reliance on an interconnection based solely on AESO Standard Facilities to be acceptable. As noted by the Cities, this implies that a substantial contribution would be required just to achieve a minimum acceptable level of service.

The Board does not find that the AESO has an obligation to equalize service levels to the extent advocated by some parties. The Board notes Decision 2001-6 where it held that there is no analogue to the postage stamp rates principle that would mandate the AESO to provide postage stamp service. The Board also notes that the notion of designating costs as system or customer-related on the basis of whether a looped or a radial interconnection was built was adopted by the Board in Decision 2001-6 in spite of the fact that certain parties had argued in that proceeding that it would be unfair for customers served by a less reliable radial interconnection to have to pay a contribution while customers who received more reliable looped service paid no contribution.

The Board considers that the evaluation of a set of reliability criteria, including the POD service level criteria, is influenced by economic considerations. That is, the AESO must consider the extent to which the costs of providing higher standards of facilities justify the increase in benefits to users in the form of increased reliability. In addition, the Board also considers that the manner in which the benefits of increased reliability are distributed amongst the AESO’s customers should also be a significant consideration in how aspects of the reliability criteria, including the AESO Standard Service definition/POD Criteria, are devised.

In this regard, the Board notes that the AESO’s decision to adopt within its reliability criteria the WECC practice of excluding radial customer interconnections from the general scope of the AESO Reliability Criteria. This reflects the fact that an outage on a radial interconnection “downstream” of the bulk system will affect the radially connected customer, but should have limited impact, if any, on other AESO customers not served by the radial interconnection. As a consequence, the Board considers that the benefit of increased electric service reliability arising from higher standard and/or redundant interconnection facilities accrues primarily to the radially interconnected customer rather than to AESO customers at large.

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80 Decision 2001-6, p.74
81 Decision 2001-6, page 74
Additionally, the Board notes that the need for absolute reliability amongst AESO customers is unlikely to be uniform, since different customers will experience different types and severity of consequences from electric service disruptions. The Board notes that alternative arrangements (such as backup power supplies), other than interconnection facilities may be made to deal with potential service disruptions. As such, the Board considers it to be economically efficient that the contribution policy should provide appropriate economic signals which pass along the costs arising from the installation of facilities beyond standard facilities to the specific AESO customer requesting the interconnection.

The Board considers that the principal concern that the AESO’s existing customers might have with a minimum standard service definition relates to the possibility that the cost of optional facilities might actually dissuade a customer from making an investment and interconnecting with the system. If this were to occur, existing customers would not enjoy the benefit of being able to transfer a portion of the burden of the AESO’s embedded system costs to a new customer. However, based on evidence available in this proceeding, this is not a substantial concern of the Board at this time. In particular, the Board notes that, while TCE presented analysis in its argument designed to show the high economic costs that would arise from a prolonged disruption in service\textsuperscript{82}, a corollary of TCE’s analysis is that customers will place a high value on reliability assurance at the time they are considering their initial investment as well. As a result, absent information to the contrary, the Board expects that customers facing substantial optional interconnection facility costs should generally be presumed to be willing to make a decision to invest in providing the minimum level of reliability that their operations require.

**Analysis of Interconnection Facilities at Existing AESO PODs - Rate Shock**

Regarding TCE’s submission that the AESO and its predecessors have generally provided a second transformer at system rather than customer expense, the Board does not agree. In arriving at this determination, the Board takes particular note of the AESO’s rebuttal evidence which suggests that a significant number of the second transformers may have been installed because the AESO and/or its predecessors determined that the cost of an interconnection using a configuration with two smaller capacity transformers was more efficient or cost effective than an interconnection devised using a single large capacity transformer. In any event, the Board finds that even if TCE’s interpretation of the statistics was to be accepted, it is clear from the statistics provided during the proceeding that a significant number of PODs greater than 15 MVA are presently served by a single transformer. As such, the Board is concerned that the adoption of TCE’s additions to the proposed AESO Standard Facilities definition could establish a de facto minimum standard for a second transformer in instances where such facilities have not historically been deemed to be warranted.\textsuperscript{83}

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\textsuperscript{82} At p. 44 of its Argument, TCE estimated that the value of expected energy not served arising from a 7 day disruption of a 90% load factor 30 MW industrial load would be approximately $54.4 million.

\textsuperscript{83} The Board is in general agreement with the AESO’s observation at p. 47 of its Argument that a greater emphasis should be placed on the aspect of the AESO Standard Facilities definition focusing on the “least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria” and comparatively less on the one-line/one-transformer aspect of the definition. Conversely, however, the Board does not agree with the suggestion of AE the one-line/one-transformer standard is inherently contradictory with good transmission practice and should thus be removed from the decision. That is, notwithstanding that the good transmission practice should govern decision making in specific situations, the Board considers that the one-line / one-transformer standard provides a useful reference point to AESO customers and may appropriately be included in the AESO Standard Facilities definition.
The Board further notes that, to the extent that potential AESO customers are able to assess the costs and benefits associated with higher or lower levels of reliability prior to committing to an investment, such customers will not be harmed and do not experience rate shock in the manner suggested by TCE. As such the Board does not agree with TCE’s view that the adoption of the AESO’s proposed Standard Facilities definition constitutes rate shock for new customers.

**Alignment with Discos Contribution Policies**

The Board notes that two documents filed during the proceeding received some prominence in some parties’ discussions of the AESO Standard Service. These documents are the “Distribution Point-of-Delivery Interconnection Process Guideline – Typical Supply Arrangements” (Typical Supply Arrangements Document) and the “Distribution Point-of-Delivery Interconnection Process Guideline – Standard of Service” (Standard Service Document). The Board understands that these documents were prepared in conjunction with the new Interconnection Redesign Process initiative described in Section 6.3 of the Application.

The Board notes that TCE has pointed to the Typical Supply Arrangements Document as being supportive of its contention that, at a breakpoint of approximately 15 MVA, customer interconnections tend to require interconnection facilities beyond a single line/single transformer configuration. TCE also pointed to the Standard Service Document as supporting its view that the determination of standard interconnection facilities should be based on a maximum restoration time standard. The Cities similarly appear to suggest that aspects of the Interconnection Redesign Process documents may be interpreted as defining minimum standards. The Board does not share this view.

The Board understands that an over-riding goal of the Interconnection Redesign Process initiative is to streamline and standardize the interconnection process with an eye towards shortening timelines, including the time required to obtain Board approval(s). In this respect, the Board considers that the identification of common aspects of interconnection projects including typical service and facility arrangements should be helpful in reducing the turn-around time for processing interconnection applications. The Board notes, however, that when it is called upon to assess the overall need for an interconnection project pursuant to Section 34 of the EUA, the Board’s determination of need is typically straightforward because the technical specifications have been worked out by the end-use customer and the AESO in advance, based primarily on the customer’s requirement for a defined level of reliability. Accordingly, the Board notes that when it approves the need for a customer interconnection project, the Board does not consider that such an approval should imply, in any respect, that the Board agrees that the facilities built for an interconnection project should be regarded as standard facilities for the purposes of applying the contribution policies of either the AESO or the applicable Disco.

In this regard, the Board notes that a disclaimer warning parties not to infer interpretations of contribution policies is included in the introductory sections of both of the Interconnection Redesign Process documents filed in the Application proceeding. The Board considers that this disclaimer is important and needs to be heeded in the present case.

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**Footnotes:**

- Exhibit 23-016 (Response to BR-TCE-1)
- Exhibit 02-033-004, TCE.AESO-238(a) Attachment entitled “Distribution Point-of-Delivery Interconnection Process Guideline – Standard of Service”
- Exhibit 30-006, page 1 and Exhibit 02-033-004, page 1

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Notwithstanding the above, the Board agrees with the comment of the Cities that it may be somewhat unrealistic to expect that these documents could not have some influence on the determination of standard service. It is of concern to the Board that the above referenced documents could be interpreted such that, for Discos, facilities above a single line and transformer, could be considered standard for loads above a certain level. This could provide incentives for customers to generally favour interconnection to a distribution system over interconnection to the AESO system.

The Board considers that it would be an economically inefficient and undesirable result if the type of interconnection (i.e. distribution vs. transmission) sought by a customer was driven more by a Disco's more attractive contribution policy than on the basis of which type of interconnection was the most technically sound and cost efficient. Accordingly, the Board considers that it is important for the standard service definitions of the AESO and Discos to be aligned to the extent possible. For this to occur, the Board considers that an evaluation and debate must take place regarding the extent, if at all, that a minimum service norm as discussed in the Interconnection Redesign Process should be set at a higher level than a Disco's standard facilities definition for a Disco's contribution purposes. The Board considers the above described exercise to be an essential aspect of the harmonization of Disco and AESO contribution policies that should occur as soon as practicable. The Board will provide additional directions in regard to AESO/Disco harmonization process in Section 6.3.2 of this Decision.

6.1.4 Maximum Investment Formula

The AESO noted that in Decision 2001-6, the Board had supported a criterion for the design of the maximum investment formula (presently referred to as the "roll-in ceiling" in the existing tariff) such that approximately 80% of interconnection projects would not require a customer contribution. The AESO noted that it was posited by the AESO's predecessor during the course of the proceeding leading to Decision 2001-6 that setting a roll-in ceiling in this manner would have the effect of minimizing intergenerational inequities.

In the Application, the AESO noted that the use of the roll-in ceiling had not met the target of 80% of projects not requiring a contribution with 20% of projects requiring some contribution be paid. Instead, it was noted that, in practice, the roll-in ceiling has resulted in customers being required to pay a contribution only in respect of about 10% of interconnection projects.

The Application also noted that while the roll-in ceiling reflected some consideration of the forecast amount of transmission rate revenues to be paid by a customer following the customer's interconnection, the major driver of the size of the roll-in ceiling for a specific project related to the length of the DTS contract signed by the customer (the "commitment term amount").

In an effort to try to meet the 80/20 target more consistently, the AESO has proposed a new maximum investment function in the Application. The proposed maximum investment function does not include a Commitment Term component. Instead, the AESO has proposed a simpler formula under which a customer would be granted an investment allowance of $27,000 per MW of contracted DTS load, per year of DTS contract term. A graphical representation of the roll-in ceiling and the maximum investment function proposed in the Application are shown in Figure 6.1.2. 88

88 Application, Section 6, page 10
As discussed above in Section 6.1.1 the Board considers it is of primary importance that the contribution policy should send appropriate economic siting signals to new customers. The Board considers the design of the maximum investment function to be central to the goal of sending appropriate economic signals through the contribution policy. While the Board notes that the AESO has attempted to achieve a balance between economic signals and administrative simplicity, the Board considers that the maximum investment function proposed by the AESO is overly simple. As a result, it does not achieve an appropriate balance between simplicity and appropriate economic signals.

The primary concern of the Board with respect to the AESO’s proposed investment function is that it emphasizes revenues; that is, the AESO has considered the revenue stream it will receive from a prospective connection, rather than costs as a driver of the design. The Board agrees with the AESO that the current roll-in ceiling formula places a disproportionately high emphasis on the commitment term amount of the formula when compared to forecasted revenues. However, it is inappropriate to presume that a desire to downplay the influence of the commitment term component of the current roll-in ceiling formula results in a general preference for revenue based investment formulas over cost based formulas.

The Board considers that the underlying rationale for the consideration of revenues in the context of a contribution investment policy relates to the manner in which a new customer interconnection may benefit existing customers through a broader sharing of embedded system costs. In this context, the incremental transmission revenue generated by connecting the new customer is also the maximum level of the “willingness to pay” of existing customers. Furthermore, since the Board considers that a new customer may normally be presumed to be seeking an interconnection in order to obtain the benefits of electrical service rather than an investment allowance per se, the Board considers that the new customer should be provided the incentive to commit an investment as long as the costs of any required interconnection facilities are offset. Thus, there is the potential risk of creating a substantial difference between the respective willingness to pay of the new customers and that of existing customers. The difficulty in creating a utility investment policy is to determine how to design a maximum investment allowance function that will fall at a reasonable level within this range.

Based on evidence brought forward in this proceeding, the Board has determined that cost, not revenue, is the appropriate starting point for establishing the investment policy. As such, rather than being a driver of the investment policy, the Board considers that the primary role that transmission tariff revenues should play is to establish the upper limit of the investment allowance. That is, if the transmission revenues expected to be generated by a new DTS customer over the customer’s contract term are estimated to be less than the expected cost of a standard facility interconnection, the amount of maximum investment function should be limited to no more than the amount of the estimated incremental transmission revenue.

While the Board notes that the AESO has indicated that it has adopted a revenue based approach for the AESO’s maximum investment proposed in the Application, the Board considers that the AESO’s proposal is, in reality, based on the observed and/or derived costs for a set of interconnection projects of varying sizes. In contrast, the Board notes that the revenue based aspect of the AESO investment proposal related to the AESO’s decision to force the derived

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investment line through a zero intercept. The Board understands that this constraint was imposed in an attempt to reflect the fact that the AESO’s proposed rate design did not include a customer charge.\textsuperscript{90} However, the Board considers that the AESO’s adoption of the zero intercept constraint acted in combination with the AESO’s adoption of a linear form for the investment function to create a function that is excessively steep. As a result, the Board considers that the AESO’s proposed maximum investment function tends to provide an insufficient allowance for small interconnection projects and an excessive allowance in respect of comparatively larger projects.

In addition to these concerns, it is also not clear to the Board that a linear investment function will properly reflect the reduced rate at which interconnection project costs increase as peak load rises. In this regard, the Board was strongly persuaded by the testimony of the IPCAA panel\textsuperscript{91} that significant scale economies occur as the size of interconnection projects increases. As a result, the Board considers that such scale economies should be reflected in the functional form of the maximum investment curve. The Board also takes note of evidence introduced by TCE which concretely illustrated the existence of significant scale economies in respect of both transformation equipment and transmission lines.\textsuperscript{92} In light of the Board’s findings with respect to scale economies, the Board considers that it is appropriate for the AESO to assess the merits of a non-linear rather than a linear form for the maximum investment function along the lines of the “0.6 power rule”\textsuperscript{93} discussed by the Chairman and IPCAA.

The Board noted, with interest, IPCAA’s proposed approach whereby a threshold above the proposed allowable investment is incorporated into the maximum investment allowance. The Board notes that it is in the interest of existing AESO customers that the interconnection of new customers be encouraged so long as the interconnection costs to be funded by existing customers are less than the incremental transmission tariff revenues expected to be generated. Accordingly, the Board considers that it is appropriate that the maximum investment function to be applied in the longer term should include some additional “tolerance” above the amount that would be provided under an investment function strictly designed to reflect average costs. However, the Board is not prepared at this time to adopt IPCAA’s recommendation that the investment function should be increased by 25%. Instead, the Board considers that an appropriate level for this “average-cost plus” threshold should be the subject of future study of the extent to which interconnection project costs of a comparable capacity may be expected to exceed the average for that size of project.

Notwithstanding the Board’s suggestion to review the merits of a non-linear maximum investment function and provide its findings at the next GRA, the Board notes that the notion of a non-linear function was discussed only at a conceptual level during the Application proceeding. As such, the Board considers that a linear maximum investment function must continue to be utilized in the short term. Accordingly, the Board hereby directs the AESO to amend Article 9.4

\textsuperscript{90} The AESO indicates at Tr. Vol. 3, pages 875-876, that the choice of a zero intercept reflected the AESO’s proposed rate design in which DTS rates did not have a customer charge component.

\textsuperscript{91} Transcript Vol. 6, pp. 1587-1589

\textsuperscript{92} Exhibit 23-019-001 (FIRM-TCE-3 Schedule A) and Exhibit 23-019-002 (FIRM-TCE-3 Schedule B)

\textsuperscript{93} The chairman discussed the subject matter of potential scale economies in respect of interconnection projects with the IPCAA panel at TR. Vol. 6, pp. 1587-1589. In the course of that exchange, the chairman discussed with the IPCAA panel the notion that engineers typically apply a rule-of-thumb which postulates that typical engineering projects should rise by only about 60% for any 100% increase in the size of the project. While it is not the intention of the Board to prescribe a specific non-linear functional form for the maximum investment function to the AESO, the Board considers that this “point-six power rule” may provide a useful starting point for the AESO’s investigations.
of the Terms and Conditions proposed for the Application such that a minimum investment allowance reflects:

- A minimum investment allowance of $2.5 million; and
- An additional investment of $100,000 per MW of project capacity

The AESO is further directed to provide a copy of the proposed adjustments to Article 9.4 with the refiling Application pursuant to this Decision.

In respect of the longer term beyond 2006, the Board directs the AESO to conduct further study so that it may devise a more comprehensive investment function proposal which avoids the Board’s concerns with the AESO’s 2006 Application and reflects the design principles described by the Board in this Decision. The Board considers that this task will involve several distinct steps, as reflected in the following list of Board directions:

1. The Board hereby directs the AESO to conduct a study for the purpose of devising a simplified maximum investment function. Such study to be completed in time for review no later than the 2008 GTA proceeding. The study should incorporate a sufficient number and diversity of data points to enable the study to consider the current costs of several different interconnection project sizes. Interconnection project costs for the purposes of the investment function study should only reflect the costs of standard facilities as described in the AESO Standard Facilities definition approved by the Board in this decision.

2. On the basis of the results of the study described in the preceding direction, the AESO shall recommend an investment function that represents the average cost per MW of capacity. The Board expects that the resulting interconnection cost function derived will exhibit significant economies of scale and, as a result, may be non-linear in nature. For the purposes of the remaining steps of the Board’s maximum investment function directions, the average cost function derived in accordance with this step will be referred to as the “Raw Interconnection Project Cost Function”.

3. In accordance with the notion of a tolerance as discussed in the argument of IPCAA, the Board directs the AESO to analyze the results of the above study for the purposes of determining an appropriate multiplier such that approximately 80% of the projects included have a cost greater than implied by the Raw Interconnection Project Cost Function fall within the selected tolerance multiplier.

The Board directs the AESO to present the results of the above analysis for review no later than the time of filing its 2008 GTA, along with its proposal for an appropriate maximum investment formula.

6.1.5 Contribution Waivers for Expansion at Multiple Customer PODs

In this Application, the AESO proposes to waive customer contributions in respect of transmission projects at AESO PODs where multiple users are served by a distribution utility.

The elements of the AESO’s Multi-POD waiver are described in Article 9.5 of the AESO’s proposed T&Cs. Specifically, Article 9.5 provides that, effective January 1, 2006, the AESO

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94 This direction is based on the IPCAA analysis described at page 34 of IPCAA’s argument submission.
would waive all or part of the customer contribution that would otherwise be assessed against a
distribution utility for transmission facility expansions at a multiple-user POD on condition that
the distribution utility:

- Provides sufficient documentation to demonstrate that the customer contribution arises
  from a transmission project required by multiple end-use sites served by the distribution
  utility;
- Executes a twenty year System Access Service Agreement in respect of the multiple-user
  POD; and
- Agrees to flow through a pro rated share of the customer contribution that would
  otherwise apply in respect of a transmission expansion at a multi-user POD to identifiable
  customers of the distribution utility with loads greater than 2 MW.

The proposed Article 9.5 also specifies that the proposed contribution waiver would not be
available in respect of any transmission facilities above and beyond the AESO Standard
Facilities deemed to be required to provide acceptable service to the distribution utility.

The AESO submitted that the availability of a contribution waiver in respect of distribution
utility PODs serving multiple customers was necessary because:

(1) regulated utilities have an obligation to serve regardless of any limits imposed by the
    AESO’s contribution policy; and

(2) distribution utilities have little if any influence over the amount, location, or timing of the
    load growth that they are obligated to serve.

ATCO Electric\textsuperscript{95}, the Cities of Lethbridge/Red Deer and FIRM supported the AESO’s multiple
customer POD waiver proposal. EnCana, IPCAA and TCE opposed the proposal, primarily on
grounds that it would create discrimination between the AESO’s industrial and distribution
utilities. Alpaca indicated that while it did not have a view on the multiple-customer POD waiver
proposal at the present time, it considered that other aspects of the AESO’s proposed
contribution policy should be determined by the Board before further consideration is given to
the multiple customer POD waiver.

The Board agrees with the AESO’s observation that there are fundamental differences between
distribution utilities and industrial customers. In particular, the Board agrees that whereas a
regulated distribution utility has a statutory obligation to provide adequate service in response to
load growth that it cannot dissuade or otherwise control, there is no analogous requirement on an
industrial customer to ensure that it receives electric service at some predefined minimum level
of service and reliability. The Board further notes that, unlike the AESO’s industrial customers,
the AESO’s distribution utility customers have the ability to collect revenues reflective of the
prudent costs of carrying out their statutory obligations through the regulated distribution
utility’s tariff. As such, in the event that a transmission facility investment required by a
regulated distribution utility is not fully covered under the AESO’s contribution policy, the
distribution utility should generally be able to expect that the costs of a customer contribution
paid to the AESO may be recovered by flowing the cost of the customer contribution through the

\textsuperscript{95} In addition to supporting the multiple customer POD contribution waiver, AE also indicated that the availability
of such a waiver should be back dated to January 1, 2005 rather than only being available as at January 1, 2006.
regulated distribution utility's revenue requirement. By contrast, industrial customers do not enjoy a comparable guarantee that they will be able to pass along any customer contribution costs through the costs of the products they may produce.

Notwithstanding these noted differences, the Board is not persuaded that it is necessary or appropriate to grant a waiver from customer contributions otherwise payable by the distribution utility to the AESO. In particular, given that a distribution utility should generally be able to recover customer contributions arising from AESO facility projects through the distribution utility's own tariff, the assessment of a contribution waiver is reduced to a question of whether the contribution costs should be spread more narrowly through a specific distribution utility’s tariff or shared more broadly under a waiver scenario that would see these costs being absorbed within the AESO’s revenue requirement.

In this regard, the Board notes that it was previously determined in Decision 2001-6 that the AESO’s predecessor would not violate the principle of postage stamp rates by adopting a contribution policy that could require some distribution utilities to pay somewhat higher contributions than other distribution utilities. The Board further notes that while narrative in the Application appeared to suggest that the AESO’s existing contribution policy might be regarded as violating certain aspects of postage stamp principle, the AESO confirmed in an information request response that statements on p. 88 of the Application linking the existing contribution policy to a possible postage stamp principle violation had previously been disposed of in Decision 2001-6.

The Board considers that it is both consistent with past practice and consistent with the desire to send efficient pricing signals through the contribution policy that customer contribution costs incurred by a distribution utility should be recovered through the distribution utility’s own tariff. Accordingly, the Board hereby denies the AESO’s proposed Article 9.5 of the Application’s proposed T&Cs in its entirety.

6.1.6 Other Contribution Policy Issues

6.1.6.1 Application of Contribution Policy to Dual-Use Sites

In the Application, the AESO noted that its existing contribution policy determines the extent to which the load or supply customer contribution policies apply to a dual use customer using a formula based on the ratio of the DTS and STS contract capacity to the aggregate contract capacity at the customer’s site. Under this formula, the amount payable under the load contribution policy is determined in accordance with the following formula:

\[ \text{[DTS} \div (\text{DTS + STS})] \times \text{customer-related costs} \]

Similarly, the amount payable as a generator in respect of local interconnection costs is determined as:

\[ \text{[STS} \div (\text{DTS + STS})] \times \text{cost of the local interconnection} \]

96 Decision 2001-6, page 55
97 BR-AESO-019. (Note: The AESO’s response to BR-AESO-019 goes onto indicate that the passage found at p. 88 of the Application implying a possible postage stamp violation should be considered to be withdrawn from its evidence.)
The AESO noted that the dual-use ratio was intended to provide a reasonable sharing of customer-related costs between load and supply in consideration of the fact that a significant portion of the load customer’s interconnection costs may be rolled into rates through the operation of the roll-in ceiling while the generator costs are paid fully by the generator as a customer contribution. The AESO noted that, in particular, the dual-use ratio was beneficial in limiting the amount of contribution provided on the basis of the commitment term component of the roll-in ceiling which, since it is not revenue-based, would provide a contribution to generators without a corresponding revenue stream.

The AESO indicated, however, that because its proposed maximum investment policy had eliminated the commitment term amount from the roll-in ceiling formula, it was no longer necessary to address potential mismatches between investment and revenue through the dual-use formula. Accordingly, the AESO proposed to eliminate the dual-use formula in favour of the application of a “load first” principle. Under this method, the AESO proposed to determine the dual use customer’s interconnection contribution by first determining what the contribution would be if the customer were treated as a load customer. Accordingly, if the application of the load customer contribution provided full coverage for the cost of a standard facility interconnection, the load first principle would mean that no contribution would be required. In the event that the application of the maximum investment function for load did not cover the full cost of providing a standard facility interconnection, the customer contribution would be the residual cost after subtracting the maximum investment allowance from the cost of the standard facility interconnection, as illustrated from the following formula reproduced from the Application:

\[
\text{customer contribution} = \frac{\text{total customer-related costs for load and generator}}{\text{local investment for load}}
\]

The AESO’s proposed “load first” formula was supported by IPCAA and by TCE but was opposed by FIRM.

The Board notes that the AESO’s proposition that a “load first” principle should apply in determining the contribution for dual-use customers is strongly premised on the elimination of the commitment term amount from the maximum investment formula. This would be replaced by an investment formula driven entirely by the number of MWs of DTS contract capacity and contract terms that the customer signs up for.

However, the Board notes that while the maximum investment function adopted by the Board in Section 6.1.4 of the Decision above no longer includes a significant commitment term component, the formula prescribed by the Board still provides a minimum contribution of at least $2.5 million. Accordingly, while the Board considers that there is a better match under the new load contribution policy between interconnect costs and DTS revenues, the adoption of the AESO’s proposed “load first” formula would still provide a substantial contribution to generators who sign up for minimal DTS capacity.

In light of this finding, the Board considers that it is still necessary to maintain the dual-use formula to ensure that AESO customers that are primarily generators are not able to gain an effective exemption from the clear policy intent of the Government’s Transmission Policy and the Transmission Regulation whereby generators are to pay for their local interconnection costs. Accordingly, the Board hereby directs the AESO, in its refiling, to re-instate the dual-use
formula as described in Article 9.3 of T&Cs of the currently approved tariff. The Board considers that alterations to the wording of the dual-use clause should only be done for the purposes of maintaining consistent numbering and references to other parts of the AESO’s T&Cs.

6.1.6.2 Staged Load

The AESO proposed\(^98\) to apply the customer contribution policy in a manner that would accommodate material increases or decreases in a customer’s load, provided the customer signed a DTS contract with a term that extended a minimum of five years after the start date of the last staged contract capacity. Under this proposal, the maximum investment allowance accounting for staged changes in load, would be made available to the customer at the start of the project. However, it would be adjusted to reflect the staged nature of the load by taking the present value of the investment in the incremental load for the period of the contract term after the staged increase or decrease in the contracted capacity was to take place.

The AESO’s staged load proposal was supported by FIRM. However, FIRM also submitted that if the staged load did not materialize as planned for the purposes of determining the available investment allowance, the customer receiving staged treatment should be obligated to repay any excess facility investment allowance that may have been based on the assumed staging of the contracted load.

The Board notes that no parties opposed the proposal to permit the staging of load levels for the purposes of determining maximum investment allowances. The Board likewise supports and approves this proposal. However, the Board notes that the proposal to permit load staging in the determination of available investment is not specifically described in the AESO’s proposed Article 9.4 or elsewhere in the AESO’s Article 9 contribution policy T&Cs. As such, the Board shares the concern of FIRM respecting the obligation of a customer to provide a refund if the staging assumptions used initially do not materialize.\(^99\) Accordingly, the Board hereby directs the AESO to propose a specific additional provision of Article 9 which more specifically describes the consideration of staged loads for both investment allowance and refund determination purposes with its refiling Application.

6.1.6.3 Distribution vs Transmission Interconnections

The Board notes that Article 9.1 of the existing tariff’s T&Cs requires the AESO to assess the appropriate way of providing service to a customer requesting a new point of connection or expansion of an existing point of connection. Article 9.1 further provides that, if the AESO determines that the most economic option for providing that service to a customer is a distribution-level extension or isolated generation or, if the customer’s request primarily represents a shift of supply or demand from an existing point of connection, then the customer will pay the full cost of the project.

The Board notes that the parts of the proposed Article 9.1 describing the AESO’s obligation to assess the appropriate type of interconnection that should be provided to a customer are largely unchanged from the comparable part of the existing Article 9.1. The Board concludes, however, that some adjustment of Article 9.1 is necessary to bring it into alignment with the “optional

\(^98\) Application, Section 6, pages 11-12

\(^99\) Despite this concern, the Board notes, however that the AESO has the right to require a refund in this situation pursuant to the AESO’s proposed Article 9.7.
service” concept discussed in Section 6.1.3 above. Of specific concern to the Board is this passage from the proposed version of Article 9.1:

If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), or that the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension (“the project”). [Emphasis added].

The Board is concerned that, as currently proposed, the referenced portion of Article 9.1 does not align with the concepts of AESO Standard Service and Optional Service as described elsewhere in this Decision. In particular, the above referenced passage indicates that no investment allowance will be permitted on any portion of the costs of a transmission interconnection project when the AESO has determined that a distribution project is more economic. However, the Board considers that it is appropriate that an investment allowance should be permitted in respect of that portion of a project’s costs up to the cost of the foregone lower cost distribution or isolated generation service option.

The Board agrees, however, that a full customer contribution should be required in respect of the difference in cost between a lower cost distribution option and the selected transmission option. Accordingly, the Board directs the AESO to amend Article 9.1 to reflect the Board’s above noted findings as part of its refiling.

6.1.6.4 Discount Rates

Article 9.12 of the proposed T&Cs updated the formula used to determine the discount rate that may be used for various purposes within the contribution policy. The Board notes that no parties opposed the AESO’s proposed changes. The Board also supports the proposed changes. Accordingly, the Board hereby approves Article 9.12 as filed.

6.1.6.5 Common Facilities

Article 9.8 of the Application’s T&Cs proposed to change the way the AESO deals with situations arising when one or more additional customers make use of local interconnection facilities originally built for and funded by an existing AESO customer.

Unlike the existing tariff’s Article 9.8, which describes the allocation of interconnection facility costs amongst existing customers and any newly interconnecting customers using the same facilities, the proposed Article 9.8 simply provides that in any situation in which a new customer makes use of an existing customer’s local interconnection facilities, the cost of such facilities will simply be deemed to be a “Common Facility” as defined under Article 9.8 and the costs will then be designated as system-related to be borne by all AESO customers. The AESO indicates in the Application that its proposed treatment of common facilities for the purposes of Article 9.8 was devised to comply with Subsection 16(4) of the Transmission Regulation.

The AESO stated that it had interpreted the Government’s choice of the words “all users” within Subsection 16(4) to denote a specific policy intent as set out in the following response to Board IR 026:

... “all users” as “all users of the transmission system” simply because there is no qualification of usage in section 16(4). For example, if limitation has been intended,
section 16(4)(a) could have stated “all users of those facilities; or used other qualifying words.”

In argument, FIRM took issue with certain aspects of the AESO’s interpretation of Subsection 16(4) and in particular with the broad nature of the words “all users” in Subsection 16(4). In FIRM’s submission, the reference to “all users” should be interpreted as “all users of those facilities”. FIRM noted that this interpretation would be consistent with the principle of cost causation where costs should be borne by those causing the costs and with the Board’s long standing practice of applying a revenue test for shared facility costs. FIRM further submitted that, if the intent of the drafters of the legislation had been to overturn well established regulatory practice, the Transmission Regulation would have included specific language, such as “all users of the transmission system”, to effect such a change. In the absence of such language, FIRM submitted that the meaning of “all users” within Subsection 16(4) should be interpreted in a manner consistent with established Board practice and cost causation principles. FIRM noted that while its comments were primarily devised in relation to the circumstances of load customer interconnections, FIRM considered that a similar interpretation of Subsection 16(4) (references to “all users” should be interpreted as “all users of those facilities”) should also be applied when one or more new customers are added to the local interconnection facilities of an STS customer.

FIRM further submitted that, if the revenue test in relation to shared facilities were eliminated through the adoption of the AESO’s proposed Article 9.8, a door to potential abuse in the future could be opened. FIRM submitted, for example, that a large customer needing new facilities involving a significant customer contribution may attempt to avoid a contribution by having another customer, perhaps an affiliate, request a second connection somewhere along the new facility line for load smaller than the original facility. In this situation, FIRM suggested that the AESO’s proposal would have the effect of funding the interconnection facilities of both of the customers in the example at the expense of all users of the system.

In reply to FIRM, the AESO submitted that additional background pertinent to the interpretation of Subsection 16(4) is provided by the Government’s policy paper Transmission Development: The Right Path for Alberta\textsuperscript{101} which states:

| Local “system” upgrades typically include items such as changes to stations A and B (i.e. circuit breaker change-outs, protection upgrades), reconductoring of Line A-B, or other modifications to the local system to accommodate the generator. These costs will be considered “system” costs and will not be recovered specifically from a particular generator but will be treated like all other system costs. |

Having regard to this passage, the AESO submitted that its proposed re-designation of customer costs as system costs as described in Article 9.8 aligns with both the Transmission Regulation and with government policy, and should therefore be approved as filed.

While the Board acknowledges the public policy concerns raised, the Board must approach this issue first as a matter of statutory interpretation. If the language used by the legislation is clear, then the Board must give effect to it. To construe any legislation, including its governing legislation, the Board applies ordinary principles of statutory interpretation. The Board will

\textsuperscript{100} While not specifically indicated in FIRM’s argument, the Board understands that the referenced passage is part of BR-AESCO-026 (Exhibit 02-016).

\textsuperscript{101} Exhibit 030-027
endeavour to give statutory language its plain and ordinary meaning having regard to its context. The Board will also interpret provisions in different enactments with similar subject matter so as to avoid conflict between them.

Accordingly, the Board has first approached the question of the extent to which interconnection costs are to be shared among multiple customers by considering the language used in the beginning of Subsection 16(4) which reads as follows:

16(4) If another person makes use of the facilities for which a local interconnection cost has been paid, (emphasis added)

As is clearly shown in the above provision, the use of the modifiers “another” before “person” and “the” before “facilities” narrows the consideration of interconnection costs to a particular customer in respect of a particular interconnection as opposed to all customers and all interconnections in general. This introductory provision must then be read as part of each of the subsections that follow. Thus the whole section read together would be as follows:

If another person makes use of the facilities for which a local interconnection cost has been paid, the cost of the use of those facilities by that other person or persons must be allocated to all users in accordance with the ISO tariff; and the original local interconnection cost, or a portion of it, must be refunded to the person who paid it in accordance with the ISO tariff.

When read as a whole, the provision supports the interpretation that the words “all users” is a reference to the cost of the use by those specific users of the interconnection facilities that are now being used by one or more persons. The Board has concluded, based on the language of Subsection 16(4) of the Transmission Regulation, that the costs of local interconnections which are used by more than one customer are to be shared amongst the other customers using that interconnection. The Board is of the view that this interpretation is consistent with the policy objectives of this scheme.

The Board considers that, even if it were possible to support the AESO’s proposed broad interpretation of the effect of Subsection 16(4) as valid, the Board would have very significant concerns about the potential abuse by customers seeking to minimize their contribution costs that could result in the application of Article 9.8, as proposed. In that event, the Board would have required the AESO to devise a number of safeguards to ensure that the potential abuses identified by FIRM would not occur.

With respect to the submission of the AESO that its interpretation of Subsection 16(4) of the Regulation is supported by the Government’s Transmission Policy paper, the Board notes that the passage referenced by the AESO in its reply argument occurs within the context of a discussion of Generator System Contribution. However, the Board notes that the referenced section of the policy paper does not address the question of whether secondary users of previously constructed local facilities should trigger a re-designation of a customer cost to a system cost. In any event, the Board notes that the passage from the Transmission Policy referenced by the AESO merely describes the generic dividing line for system and customer costs for the purposes of the generator contribution policy.

In light of the above noted findings, the Board considers that Article 9.8 must be amended. Accordingly, the Board directs that, in its refiling, the AESO provide a revised version of
Article 9.8 based on the wording of the existing Tariff’s Article 9.8. The proposed revision should exclude current sub-Articles (a)(i) and (ii) as they are no longer relevant, given the investment formula approved by the Board.

In addition to the above, the Board notes that the AESO proposed to drop Article 9.8 (c) from the existing Tariff’s T&Cs on the basis of the AESO’s assessment that the administrative burden associated with contribution refunds was not expected to be sufficiently onerous to require the continuation of the $50,000 threshold.

The Board notes that no parties commented on the AESO’s proposal to eliminate the $50,000 threshold. The Board likewise has no objections. However, the Board also notes that AESO’s proposal to eliminate the $50,000 minimum refund threshold may have been premised on the Board’s adoption of Article 9.8 as applied-for by the AESO. The Board notes that the AESO’s proposed Article 9.8 provided for a straightforward transfer between existing customers (i.e. “the system”) and the customer originally paying a contribution in respect of local interconnection facilities. However, with the Board’s variance of the proposed AESO wording of Article 9.8, the Board considers that the administrative costs associated with arranging for the transfers of money between old and new customers served by an existing local connection may be more complex and onerous than initially contemplated by the AESO.

In light of the above, the Board considers that the AESO should have the option of reinstating a minimum contribution threshold if, in the AESO’s opinion, the administrative burden requires this. Accordingly, the Board hereby directs the AESO in its refiling to advise the Board as to whether the minimum contribution refund threshold as provided in the existing AESO Tariff’s Article 9.8 (c) should be reinstated and, if so, to amend its T&Cs accordingly.

6.1.6.6 Conditions for Customer Contribution Adjustments

Article 9.6 of the proposed T&Cs provides directions to the AESO for dealing with situations when changed circumstances result in changes in the estimated cost of an interconnection project cost as compared to the initial cost estimate provided to a customer.

The Board notes that no parties raised concerns with Article 9.6. The Board has also reviewed Article 9.6 and considers that it should be approved as filed.

6.1.6.7 Pre-Paid Operations and Maintenance Charge

Article 9.13 of the proposed T&Cs provides for a prepaid operations and maintenance (O&M) charge calculated as 12% of the customer-related costs of an interconnection to be applied to all new STS customers.

For all other AESO customers, including DTS customers, Article 9.13 also provides for a prepaid O&M charge to be levied. The charge is to be calculated as 12% of the cost of any interconnection facilities deemed to be in excess of the AESO Standard Facilities for the interconnection project.

The AESO considered that its proposal to apply a prepaid O&M charge to newly connecting STS customers is consistent with Subsection 16(1)(a) of the Transmission Regulation which requires newly connecting generators to pay all local interconnection costs for connecting to the transmission system. The AESO considered that as customer interconnections incur on-going
O&M costs beyond their initial capital costs, it would be appropriate to include a prepaid O&M charge to ensure that load customers do not pay costs related to generator interconnections.

Alpac was opposed to the adoption of the AESO's proposed prepaid O&M charge to generators because, in its view, doing so would not be consistent with the Transmission Regulation and because it would create discrimination between existing and new generators. Alpac submitted that Subsection 30(a) of the Transmission Regulation must be interpreted such that all wires related costs are allocated to load customers. Additionally, it submitted that Subsections 30(b) and 16(1) of the Transmission Regulation would not support making generation unit owners responsible for on-going operations and maintenance costs. Alpac noted that Subsection 30(b) permitted three types of costs to be charged to owners of generating units:

1. interconnection costs,
2. a financial contribution towards system upgrades, and
3. location based losses charges.

Alpac submitted that the use of the specific wording in Subsection 16(1)(a) that "local interconnection costs" are "payable by an owner of a generating unit for connecting to the transmission system" does not support an interpretation making generating units financially responsible for the operation and ongoing maintenance of portions of the transmission system. Alpac also noted that the AESO had confirmed that while prepaid O&M charges were applied to generators under the vertically integrated regime existing in Alberta prior to 1996, this practice was not continued from 1996 on under the tariffs of the AESO’s predecessors (GRIDCO and EAL). Accordingly, Alpac submitted that re-instituting a prepaid O&M charge to generators after a decade’s absence would be unfair and would provide an unwarranted first-mover advantage for the generation unit owners who have developed projects since 1996.

While FIRM was supportive of a prepaid O&M charge, FIRM submitted that evidence presented during the Application proceeding did not support 12% as the appropriate level for the surcharge. In the absence of supporting evidence, FIRM submitted that the prepaid O&M surcharge should be set with regard to the ratios of “other expenses charges” to capital charges for the duplication avoidance tariff riders contained in the AESO’s current tariff. FIRM submitted that on the basis of its analysis, the prepaid O&M surcharge should increase from the AESO’s proposed level of 12% to 15.2% until such time as a more detailed review has been completed by the AESO.

The Board has established four considerations in its disposition of the AESO’s proposed prepaid O&M charge, namely:

- Whether the implementation of a prepaid O&M charge would be beneficial to the orderly evolution of the transmission system.
- Whether the application of a prepaid maintenance charge is consistent with provisions of the Transmission Regulation.
- To the extent that it is consistent with the Transmission Regulation, how should the amount of the charge applied to specific customers be determined.
- If a prepaid O&M charge is adopted, what is the appropriate amount of a prepaid O&M charge in the immediate term and/or in respect of future years.

The Board has considered each of these elements separately as they apply to STS customers and DTS customers.
STS Customers
With respect to the first question, the Board considers that the notion of a prepaid O&M charge is consistent with the goal of providing an appropriate economic signal to new customers considering an interconnection to the AIES. Accordingly, the Board considers that a prepaid O&M charge should be pursued to the extent that doing so is in compliance with legislation.

With respect to the second consideration, however, the Board considers the application of the AESO’s proposed prepaid O&M charge to STS customers to be problematic. The Board agrees with Alpae that Section 30 of the Transmission Regulation describes the types of costs that may be charged to generators. That section limits the recovery of costs from generators to:

- Local interconnection costs as set out in Section 16; and
- Financial contributions for transmission system losses (as further described in Section 22) and system upgrades (as further described in Section 17).

With regard to the foregoing list, the Board considers that the only manner in which the Board could conclude that a prepaid O&M cost could be applied to a generator is if the proposed charge could be treated as being part of the “local interconnection cost to connect its generating unit to the transmission system”. Applying ordinary provisions of statutory interpretation, the language in this provision clearly restricts the responsibility for generators to assume the costs necessary to connect to the transmission system. The language does not contemplate any ongoing costs beyond the initial connection costs. This is borne out by the inclusion of the phrase “costs to connect”.

Had the drafters of the legislation intended the owners of generating units to be responsible for ongoing costs to maintain the connection, they would have said so. Given this interpretation, the Board concludes that the AESO cannot convert an ongoing cost, such as operations and maintenance for the interconnection, to a capital cost by requiring the cost to be paid in advance. For this reason, the Board considers that the proposed Article 9.3(a) cannot be approved. Having determined that a prepaid O&M charge cannot be supported by the Transmission Regulation, there is no need to address the remaining considerations respecting STS customers.

Accordingly, the Board hereby directs that, in its refiling of the Application, the AESO shall redraft Article 9.3 so as to exclude in its entirety the Article 9.3(a) portion of the Article.

DTS Customers
As noted above, with respect to the Board’s finding respecting the first issue, the Board considers that the prepaid O&M charge may be beneficial from the standpoint of economic efficiency and from the standpoint of the desire to send appropriate economic siting and facility development signals through the contribution policy.

On the second issue, the Board considers that there is no restriction arising from either Subsection 30(a) or elsewhere in the Transmission Regulation that would preclude the use of the charge as it is applied to DTS customers.

With respect to the third question regarding the structure of the charge, the Board considers that specific improvements need to be implemented in conjunction with the AESO’s refiling. The Board is particularly concerned that, in applying the proposed DTS customer pre-paid O&M
charge only to the deemed “optional facility costs” of a new interconnection, the AESO appears
to be implicitly assuming that the combined amount of the pre-paid O&M costs associated with
the “non-optional” local interconnection facilities and the cost of the non-optional facilities
themselves will fall below the level permitted under the maximum investment allowance.
However, the Board considers that this should not be presumed, particularly in light of the
adjustments to the maximum investment function ordered by the Board in Section 6.1.4 above.

While the Board considers that the prepaid O&M charge may be improved with further research,
the Board considers that the adoption of a 12% surcharge as proposed by the AESO is a good
starting point for the purposes of the 2006 Tariff.

Accordingly, the Board directs the AESO in its refiling Application to apply the 12% prepaid
O&M surcharge such that:

- The surcharge will be determined separately for the optional and non-optional facilities;
- The portion of a DTS interconnection project’s prepaid O&M surcharge based on cost of
  the optional facilities will be fully charged out to the interconnecting DTS customer,
  consistent with the Board’s disposition of other optional facility costs; and,
- The portion of the prepaid O&M surcharge related to non-optional facilities is added to
  other non-optional facility costs and evaluated against the maximum investment function
to determine the amount of customer contribution that may be required in respect of the
  standard facility portion, if any.

While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally
appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced
that sufficient evidence has been gathered to determine that 12% figure appropriately tracks
costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate
amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge
included no later than with the AESO’s 2008 General Tariff Application

6.2 Generator System Contribution

Subsection 17(2) of the Transmission Regulation requires the AESO to collect, in its tariff, a
system contribution charge of $10,000/MW from the owners of new generators for system
upgrades to existing transmission facilities required as a result of a generator’s entry on to the
AIES grid. This subsection further directs the AESO to collect a system contribution charge of
no more than $40,000/MW from the owners of new generators who locate in areas of the
transmission system where generation exceeds load, with the amount to be based on the location
of the new generating unit relative to the load.

Subsection 17(4) of the Transmission Regulation directs the AESO to include in its tariff, a
provision for the refund to the owner of a generating unit who paid system contribution charges
pursuant to Section 17. The refund must be received over a period of 10 years from the date it
was paid unless the operation of the generating unit failed to meet satisfactory performance
standards as set forth in rules to be developed by the AESO pursuant to Subsection 17(5).

In its application, the AESO proposed to refund generator system contributions by way of 9
equal payments spread out over the 10 year period. The AESO explained that its suggested
proposal was created to allow for the event that an owner of a generator might experience
circumstances beyond its control during one year of the 10 year period, thus not satisfying the AESO’s rules for satisfactory operation for that year. The AESO reasoned that the owner of the generator should still have an opportunity to collect the full amount of the system contribution it made, despite having 1 substandard year during the 10 year period.

The AESO noted the system contribution must be paid before construction and must be refunded within ten years of payment subject to satisfactory performance. Since satisfactory performance can only begin after construction is complete, and since construction of both the generating unit and interconnection facilities takes time, Article 9.10 of its Terms and Conditions provided for the refund of the system contribution in fewer than nine equal annual amounts, based on the number of years after the commercial operation date of the generator and the ninth year after payment. However, to ensure that the interconnection proceeded, if the commercial operation date was later than five years after payment of the system contribution, one-fifth of the contribution would be forfeited for each additional year the commercial operation date was delayed beyond five years. If the commercial operation date did not occur within ten years after the system contribution was paid, the whole contribution would be forfeited. The AESO also proposed that no interest would be paid on the contributions. Rather, they would be treated as no-cost capital with any interest earned used to reduce overall AESO interest expense.\(^2\) The AESO noted\(^3\) that it would be developing the rules for performance measurement outside the ambit of this proceeding, given its understanding that Board approval of these rules is not required under Subsection 17(5).

TAU argued that allowing the AESO to implement rules concerning a generator’s minimum operation standards might unduly influence the energy market and would be contrary to the intent of the Transmission Regulation. TAU considered that the AESO’s role should be to facilitate an open and competitive energy market but not to influence the manner in which the energy market operates.

FIRM’s position in the proceeding was that the AESO should structure the timing of the refund of the system contributions over the 10 year period in a manner which would motivate the owners of generators to meet the AESO’s performance standards for operation over the entire period, especially during the initial portion of the refund period, when the impact on the AESO’s revenue requirement caused by the inclusion of these new generators would be the highest. To achieve this goal, FIRM considered that the system contribution refund amounts should increase year by year over the 10 year refund period such that the lowest percentage of the refund would be provided in the first year and the highest percentage would be available in the last year. FIRM considered that this approach appropriately reflected the front end nature of the expenditures on system transmission facilities built for the benefit of the owners of generators. FIRM indicated that its approach could be combined with the AESO’s recommendation to withhold 1/5 of the system contribution refund for each year after the 5th year in which a generator was still not interconnected.

With respect to TAU’s concern that the imposition of rules concerning minimum generator output by the AESO may unduly influence the market, the Board notes that Subsection 17(5) of the Transmission Regulation clearly states that the AESO “must make rules to be used to assess the satisfactory performance of a generating unit by generating unit type”. The Board notes that

\(^{102}\) Application, Section 6, page 26
\(^{103}\) Application, Section 6, page 27

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the AESO has held, and has stated its intention to hold in the future, additional workshops around the development of these rules, and further that the AESO has acknowledged that it will utilize the input it has received in this proceeding in the development of these rules.

While the Board does not wish to discourage the AESO’s stated intention to consult with stakeholders in the development of these performance rules, the Board expects that the AESO, in developing its rules, will adhere to reasonable commercial principles in their creation regardless of the input received during the consultation process. The Board notes that the AESO has jurisdiction over the development of the rules. However, the Board retains jurisdiction over the evaluation of such rules in the event of a complaint further to Section 25 of the EUA. As these rules have not been developed, the Board will not comment further on the concerns expressed by TAU and expects TAU to take this matter up with the AESO as part of the AESO’s consultation process.

With respect to FIRM’s proposition that the system contribution refunds increase in amount over the 10 year period, the Board considers this option has considerable merit.

The Board is concerned that AESO customers should not face undue risks that system investments that may have been significantly predicated on the facilitation of an open and competitive generation marketplace should become stranded at the cost of DTS customers as a result of a generator owner’s failure to fulfill its commitments. The Board considers that the back-end loading of refunds reflects the fact that the AESO is required to place considerable reliance on the forecasts of generator owners in devising its long term transmission plans. As such, the Board considers it fair, in light of the generator owner’s ability to obtain a full or partial refund of the system contribution costs that it paid, to place some onus on generator owners to ensure that capacity built on their behalf is appropriately available and satisfactorily utilized.

The Board notes that load customers bear the risk of additional capital and interest costs in the event that a generator owner does not meet the commercial operation date for delivery of energy to the transmission assets that the owner requires from the AESO and for which date the AESO implemented its transmission system upgrade plans.

Having considered all of the above, the Board hereby directs the AESO to provide an amended Article 9.10 of the Terms and Conditions in its refiling application in accordance with the following parameters:

1. Payment of all of the charges pursuant to Subsection 17(2) shall be made prior to the date of construction. The Board recognizes that Subsection 17(3)(e) only requires the owner of a generator to pay the charges owing under Subsection 17(2)(b) before commencement of construction of the local interconnection facility. However, the Board considers that prepayment of all costs, either customer contribution or system contribution, should be paid prior to the start of the commencement of activities related to the construction of any new transmission facilities necessary to provide the requested service. This will benefit the public interest by providing the maximum level of security from the outset. This will also encourage new generators to achieve commercial operation at the earliest time in order to realize their refunds, and will also be in the interests of all Albertans as they seek to realize the benefits of such generation as soon as it can reach commercial operation.
2. Any refund paid to a generating owner pursuant to Subsection 17 (4) shall be paid out no later than 10 years following the date of original payment but shall not be due and owing until after the commercial operation date for the generating unit has been achieved provided that the commercial operation date is before the expiration of the 10 years. This will, of necessity compress the refund period to a remaining period of less than 10 years in most, if not all, circumstances. For purposes of clarity, commercial operation date means the date agreed to by the AESO and the generator owner when the plant requires the transmission assets requested for delivery of energy to the AESO.

For example, assume that a charge is paid to the AESO by the generator owner on January 1, 2006 pursuant to Subsection 17 (2). In accordance with Subsection 17 (4)(a) of the Transmission Regulation, and assuming satisfactory performance, the generator owner would be entitled to receive a full refund of its payment by no later than December 31, 2015. However, if the commercial operation date is January 1, 2008, the AESO will only have 8 rather than 10 years to pay out the refund.

3. In the event that a generator owner does not commence the delivery of energy at the levels agreed with the AESO at the time that the generator contributions were provided to the AESO by the commercial operation date for any reason whatsoever, then for each year or portion thereof that the date is delayed, the refund for that year or portion thereof will be forfeited.

Again, in consideration of the example above, in the event that the commercial operating date is not January 1, 2008 as originally provided to the AESO but is January 1, 2009, then the AESO shall deem that entire period to be one in which the generator owner failed to meet satisfactory performance standards and as such, the AESO will be entitled to retain that portion of the refund that otherwise would have been payable that year. The overall schedule over which the refund is to be paid will not change.

4. Once commercial operation of the generating unit has commenced, in the event that a generator owner fails to meet satisfactory performance standards, any refund will be forfeited for that period.

5. The refund amount shall be structured in a backend loaded manner over the refund period such that 25% of the total refund shall be paid out in equal payments per year over the first half of the refund period and 75% shall be paid out in equal payments per year over the last half of the remaining period.

Using the example outlined above, in the event that a generator owner becomes eligible for a refund as of January 1, 2008 (the commercial operation date) and again assuming that the payment period ends December 31, 2015, then, for the years 2008 to 2011, 25% of the total eligible refund is available to be refunded in 4 equal payments while for the years 2012 to 2015, 75% of the total eligible refund is available to be refunded in 4 equal payments.

6. The AESO shall apply any forfeited refund amounts to a deferral account and any balances in that account shall be considered a revenue offset to its revenue requirement in a subsequent GTA.
7. No interest shall be payable by the AESO to a generator owner on any refund amounts.

6.3 Contribution Policy Next Steps

6.3.1 Contribution Policy Implementation Timing

The Board notes that the Application proposed that the Tariff should come into effect on January 1, 2006 which is consistent with the legislative timing required by Subsection 31(3) of the Transmission Regulation.

6.3.2 Disco/AESO Contribution Policy Harmonization

The Board notes that a concern about the need to advance the harmonization of the contribution policies of the AESO and distribution utilities has been discussed in several parts of this decision. In light of this concern, the Board considers that it would be beneficial for the AESO to assume a leadership role towards achieving greater harmonization and coordination.

Accordingly, the Board hereby directs the AESO, in conjunction with the distribution utilities and such other stakeholders the AESO would consider to have an interest, to develop a proposal for harmonization of these contribution policies and to present the results at its next GTA.

Although the Board considers that the ultimate terms of reference for the harmonization initiative should be established by the AESO and participating stakeholders, the Board considers that it would be beneficial for the harmonization process to, at minimum, address the following issues:

- The development of a common definition of standard POD facilities as between Disco’s and AESO (TFO) connected customers.
- Consideration of whether it is appropriate to establish defined “cutoffs” such as a maximum MVA capacity for the consideration of the interconnection of a new customer to a Disco and/or a minimum threshold for the consideration of the interconnection of a new customer to a TFO system.
- Consideration as to whether it is feasible or appropriate to adopt a common form for a cost based maximum investment function (i.e. a standard formula that would provide a greater cost allowance for the purposes the Disco’s and AESO’s respective investment policies with increases in the capacity of the interconnection

In conjunction with the above, the Board hereby also directs the AESO to provide a progress report on its contribution policy harmonization efforts in conjunction with its 2007 Tariff Application.

6.4 TransCanada Standard Interconnection Facilities Complaint

On September 20, 2004, TCE filed a complaint with the Board pursuant to Section 25(1)(b) of the EUA in respect of the manner in which the AESO’s current contribution policy was applied in respect of interconnection facilities built for a TCE gas storage facility near Edson, Alberta (the Edson facility). In follow up correspondence to the Board dated February 17, 2004, TCE further advised that it would be prepared to have its complaint matter addressed in the context of the 2005/2006 tariff proceeding.

Pursuant to Section 25 of the EUA, the Board, on receipt of a complaint under this provision, may, by giving written notice to the party making the complaint, investigate a complaint, decline
to investigate the complaint, hold a hearing or terminate an investigation or hearing provided the
grounds for termination as set forth in Subsections 25(4) (a) through (d) of the Act are satisfied.

In order for the Board to make a determination respecting this complaint, the Board must,
pursuant to Subsection 25 (6) of the Act, determine the justness and reasonableness of the AESO
fee complained of. In order to do so, the Board must make a determination of the justness and
reasonableness of the current tariff policy and the application of that policy to the Edson facility.
As the subject matter of this hearing was with respect to the proposed tariff policy, the Board
does not consider it advisable to address this complaint within this Application proceeding but
will consider the complaint in a separate proceeding.

7 TERMS AND CONDITIONS – OTHER

7.1 System Access Applications

The AESO proposed\textsuperscript{104} to amend Article 5 (previously 7) of the T&Cs to accord with the
AESO’s revised interconnection process. The AESO explained the new process has been
established through stakeholder collaboration that included representatives from the AESO, the
EUB, ENMAX, EPCOR, FortisAlberta, ATCO, AltaLink, VisionQuest, Canadian Natural
Resources Limited, and EnCana. The AESO stated implementation of the transmission
interconnection process is continuing to be developed among those parties.

The AESO stated the new single-stage process would allow for a more active presence by the
transmission facilities owner (TFO) and a more direct working relationship between service
providers and customers, which is intended to streamline system access applications. Although
the AESO will retain oversight of all transmission interconnections, it will no longer perform
each of the day-to-day tasks related to such projects. For example, payment of customer
contributions will normally be made directly by the customer to the TFO, although determination
and administration of customer contributions will remain with the AESO.

As part of the new interconnection process, Article 5 includes the following three revisions to the
level and applicability of system application fees. The existing fee structure was established
through the AESO’s 2002 Negotiated Settlement and was intended to create a manageable
interconnection queue by introducing fees large enough to discourage customers who did not
seriously intend to proceed with interconnection.

The AESO proposed to revise three aspects of the system application fee.

a. System application fees are proposed to be simplified and reduced. The current two-
stage application fee has been revised to a single charge in accordance with the new
single-stage interconnection process. Table 6.3.1 provides a comparison of proposed
and current fees.

\textsuperscript{104} Application, Section 6, page 27

74 - EUB Decision 2005-096 (August 28, 2005)
Alberta Electric System Operator

2007 General Tariff Application

December 21, 2007
Secondly, given that additional system costs incurred to accommodate service over a merchant
intertie fall within section 27 of the 2007 Transmission Regulation, the Board finds that
insufficient evidence was offered in this proceeding to allow the Board to determine whether the
proposed MTS rate is in compliance with section 27. Accordingly, the Board is unable to
approve this rate at this time.

The Board acknowledges that the TCE witness panel questioned the likelihood of customers
entering contracts to induce additional firm capacity to or from an intertie since before an intertie
is built, the benefits of firm import or export transactions cannot be used to offset the substantial
cost of contracting for firm MTS service. However, the Board is concerned that the potential
for customers to contract for firm MTS service to induce or advance additional deep system
capacity may nevertheless exist. This potential is of sufficient concern that the Board is not
prepared to approve the rate MTS at this time.

7.3.1.2 Merchant Opportunity Service Rates (MOS 1 Hour and MOS 1 Month)
The AESO proposed that its MOS 1 Hour and MOS 1 Month rates would generally reflect the
cost allocation principles used by the AESO to develop its proposed XOS 1 Hour and XOS 1
Month rates. The main exception was that the AESO proposed that its MOS rates should not
include an allocation of costs related to the existing interties, since the existing intertie facilities
would not be used by exporters using a merchant line to access other markets.

For energy either generated or consumed in Alberta, the Board agrees that customers using a
newly constructed merchant intertie would not require the use of the existing Alberta-British
Columbia or Alberta-Saskatchewan interties. This indicates that the minimum charge component
of the rate (based on the incremental variable cost associated with providing the service) would
be equal to or lower than the corresponding XOS rate minimum charge. However, the Board
finds that no evidence indicated that the value of the proposed merchant opportunity service
(MOS) is less than the value of export opportunity service (XOS). Accordingly, the Board finds
that the value of service based rate for MOS 1 Hour and MOS 1 Month is $3.98/MWh and
$4.36/MWh respectively, consistent with the Boards findings in section 7.2.1.

8 TERMS AND CONDITIONS OF SERVICE

8.1 Customer Contribution Policy

8.1.1 Interconnection Project Cost Function

In Decision 2005-096, the AESO was directed to undertake further research to devise a more
comprehensive investment function proposal which avoids the concerns expressed by the Board
in that decision and which reflects the design principles described by the Board in that
Decision. A proposal based on this research was to be presented in the AESO’s 2008 GTA.

In the Application, the AESO noted that following extensive debate during the 2005/2006 GTA,
the Board in Decision 2005-096 amended the maximum local investment formula to provide a

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310 Tr. Vol. 6, pp. 1209-1210
311 Ex. 005, Section 4 of the Application, p. 50 of 53, lines 13-19
312 Decision 2005-96, pp. 57-58 (Direction 13A)
minimum investment allowance of $2.5 million plus an additional allowance of $100,000 per MW of project capacity.\textsuperscript{313}

As a result of feedback obtained during stakeholder consultations, the AESO undertook to revise the investment allowances under the contribution earlier than the 2008 GTA. It is apparent that the AESO encountered obstacles related to the limited amount of available POD cost data in its efforts to gather the data required to fulfill the Board’s direction to develop a cost based interconnection project cost function. The Board wishes to acknowledge the AESO’s diligence in complying with the Board’s direction. The Board confirms that the AESO has complied with the Board’s Direction 13A from Decision 2005-096.

The AESO used the same cost function both to determine a proposed investment function under the customer contribution policy and to design the POD charge component of Rate DTS. Accordingly, to the extent that parties made submissions related to determining a POD cost function for POD charge purposes, such submissions have also been taken into account by the Board, as appropriate, in its assessment of the appropriate POD cost function for customer contribution policy purposes.

As discussed in section 5.7.3 of this Decision, the Board has determined that it is appropriate that the same underlying average cost function be used for both POD charge determination and contribution policy investment allowance purposes.

However, in section 5.7.7 of this Decision, the Board has not approved the POD cost function proposed by the AESO. Accordingly, for greater certainty, the Board confirms that the approved POD cost function set out in section 5.7.7 of this Decision is to be used as the basis for the maximum investment function. The Board discusses the additional steps required to convert the approved POD cost function into the approved maximum investment allowance function.

\textbf{8.1.2 Determination of Maximum Investment Function}

Article 9.6 of the AESO’s proposed T&Cs describes the determination of the customer contribution for a load interconnection project. Within Article 9.6, the major determinant of the customer contribution is the maximum local investment (maximum investment). In section 6.5.3 of the Application, the AESO discussed its efforts to comply with Directive 13 of Decision 2005-096.

The AESO considered that Directive 13A required the multiplier of its proposed interconnection project cost function to be consistent with a maximum investment function such that 80% of projects do not pay a contribution. Based on an analysis of sample POD cost data from its analysis of current projects sample, the AESO determined that applying a multiplier of 1.15149 to its proposed interconnection project cost function would result in 24 of 30, or 80%, of projects being fully covered by the resulting maximum investment function.

The AESO noted that the 80/20 criterion established by its predecessor was originally approved by the Board in Decision 2001-6. It further submitted that using this criterion assists in harmonizing the AESO’s contribution polices with those of the Discos and helps to preserve the

\textsuperscript{313} Exhibit 007, Section 6.3.2 of the Application
balance between the need of new customers for service and for service without subsidization from existing customers. Additionally, the AESO submitted that the 80/20 criterion supported the principles that most new customers would not see a different cost of system connection than existing customers, and existing customers should not bear any extraordinary costs of system expansion.

In argument, the AESO noted that while its proposed POD cost function had changed from the POD cost function it initially proposed in the Application, its proposed multiplier of 1.15149 did not change as a result of the revisions to the cost function since the multiplier still resulted in 80% the 30 greenfield projects being fully covered by the resulting maximum investment function.

The AESO further noted that its proposed application of the multiplier was not debated by any party during the hearing.

The Board considers that before ruling on the appropriate multiplier to be used to set maximum investment allowances under the customer contribution policy, it is first necessary to address the issue of whether a so called “80/20 Rule” should apply.

8.1.2.1 Application of “80/20 Rule”

As discussed in section 8.1.1 above, Direction 13A from Decision 2005-096 required the AESO to perform research leading to the development of a function describing the relationship between interconnection project capacity and average cost. Direction 13A also instructed the AESO to perform research into a multiplier of the AESO’s proposed average interconnection cost function that would provide a degree of tolerance above the average interconnection cost function. Consistent with the Board’s finding in section 8.1.1 above that the AESO’s interconnection project cost research complied with the requirements of Direction 13A, the Board considers that the AESO’s research into the development of an appropriate multiplier of the average interconnection project cost has complied with the Board’s direction.

It appears that Direction 13A has been interpreted by the AESO and some other parties as a general endorsement for the continuation of a so-called “80/20 Rule” previously applied to the AESO’s predecessor.314

However, the direction to devise a multiplier such that 80% of projects of the project fall under the resulting maximum investment function represented no more than a direction to conduct a one-time study. The mention of 80% in the direction should not have been interpreted as a general endorsement of an 80/20 rule as a guiding principle, nor did it require that the 80% threshold be used by the Board in determining an appropriate multiplier for the maximum investment function for the 2007 tariff.

The underlying principles intended to govern the design of AESO and utility contribution policies generally were discussed in some detail in sections 6.1.1 and 6.1.4 of Decision 2005-096. Included in the most important considerations set out in that decision are the following:

314 See Ex. 007, p. 18; Ex. 015, p. 26; AESO Argument, p. 43, p. 44, p. 79, p. 81, AESO Reply, p. 34; DUC Evidence (Ex. 229, p. 30); TCE Reply Argument, p. 11
• the underlying purpose of the contribution policy is to send economic signals to AESO customers when considering alternatives for siting their interconnecting loads;\(^\text{315}\)

• an excessive investment allowance could provide incentives for customers to pursue higher standards of interconnection facilities than required and justify doing so on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance;\(^\text{316}\)

• because the incremental revenue approach may place undue upward pressure on rates, maximum investment allowances should be at a level below a level representing the incremental revenues expected to arise from the interconnection of a new customer;\(^\text{317}\)

• investment allowances should be set with regard to the anticipated costs of establishing an interconnection reflecting acceptable standards of functionality and service established by the AESO;\(^\text{318}\)

• interconnection facility service characteristics and standards of functionality may change over time.\(^\text{319}\)

These considerations can not be assumed to be automatically addressed solely by applying an 80/20 rule test to a proposed maximum investment function.

The Board considers the following passage from Decision 2005-096 to be instructive:

The Board considers that the underlying rationale for the consideration of revenues in the context of a contribution investment policy relates to the manner in which a new customer interconnection may benefit existing customers through a broader sharing of embedded system costs. In this context, the incremental transmission revenue generated by connecting the new customer is also the maximum level of the “willingness to pay” of existing customers. Furthermore, since the Board considers that a new customer may normally be presumed to be seeking an interconnection in order to obtain the benefits of electrical service rather than an investment allowance per se, the Board considers that the new customer should be provided the incentive to commit an investment as long as the costs of any required interconnection facilities are offset. Thus, there is the potential risk of creating a substantial difference between the respective willingness to pay of the new customers and that of existing customers. The difficulty in creating a utility investment policy is to determine how to design a maximum investment allowance function that will fall at a reasonable level within this range.\(^\text{320}\)

The key concept described in the above passage is that the level of investment allowance should be targeted to fall somewhere in a range between the bookends of: (1) making the connecting customers pay for the full cost of a new interconnection and (2) providing a full contribution credit to reflect the benefit of embedded system cost sharing new AESO customer can provide to existing customers.

\(^{315}\) Decision 2005-096, p. 43

\(^{316}\) Decision 2005-096, p. 44

\(^{317}\) Decision 2005-096, p. 44

\(^{318}\) Decision 2005-096, p. 44

\(^{319}\) Decision 2005-096, p. 44

\(^{320}\) Decision 2005-096, p. 56
Setting the appropriate level for the maximum investment allowance is a balancing act. On one hand, it is desirable that the level of required customer contributions not dissuade customers from connecting to the system. On the other hand, the level of the investment allowance offered should ideally not be higher than most customers need to be incented to connect. However, as a result of additional considerations presented during the proceeding, the Board is no longer persuaded that, in and of itself, an 80/20 rule achieves the proper balance.

One piece of new information arises from section 6.5.3 of the Application regarding the way in which customer contribution levels have changed over time. This section highlighted the differences between the required customer contribution level for similar projects under contribution policies in effect in the years between 1999 and 2005 as compared to the contribution level required under the contribution policy approved in Decision 2005-096.

If the message that was intended to be conveyed in section 6.5.3 of the Application was that the level of the maximum investment allowance should be raised (because the contribution policy approved in Decision 2005-096 required significantly higher customer contributions than did previously approved contribution policies), the Board does not agree with this conclusion. The interconnection project queue appears to have grown rather than declined under the contribution policy prescribed in Decision 2005-096. The Board finds this to be clear evidence that having a maximum investment allowance which provided that more than 20% of interconnection projects must pay some contribution has not dissuaded AESO customers from proposing a greater number of new interconnections than can be immediately accommodated by the AESO and the TFOs. The Board therefore concludes that the lower investment allowance permitted in Decision 2005-096 did not discourage investment.

Another significant concern that the Board has with an 80/20 rule is that the application of such an 80/20 rule may become circular or self fulfilling, in that higher cost projects may trigger increases in the multiplier. As a result, the Board is concerned that to perpetuate an 80/20 rule may undermine the principle that the level of the maximum investment function provides an economic signal to AESO customers. For example, in Decision 2005-096 the Board expressed a similar concern in the context of its proposed pre-paid O&M charge:

The Board is particularly concerned that, in applying the proposed DTS customer pre-paid O&M charge only to the deemed “optional facility costs” of a new interconnection, the AESO appears to be implicitly assuming that the combined amount of the pre-paid O&M costs associated with the “non-optional” local interconnection facilities and the cost of the non-optional facilities themselves will fall below the level permitted under the maximum investment allowance. However, the Board considers that this should not be presumed, particularly in light of the adjustments to the maximum investment function ordered by the Board in Section 6.1.4 above.323

321 Ex. 007, pp. 28-29
322 The AESO’s response to undertaking 7 (Ex. H-023, p. 3 of 5) indicates that the load interconnection project queue had grown to 69 projects as May 18, 2007, which exceeds the total number of projects (59) reported in Attachment BR.AESO-016 (Ex. 092) over the period 1999-2005.
323 Decision 2005-096, pp 68-69
The AESO discussed the Board’s concern in that context:

The Board noted above that it was inappropriate for the AESO to presume that the combination of standard facility costs and the O&M charge would be covered by the investment level. The AESO acknowledges the Board’s position but suggests that such a principle only applies if the customer contribution policy has a set investment level. If the investment level was set at a specific value and was not based upon the number of projects that are not required to pay a contribution – which is not how the current and proposed investment policies are structured (i.e. 80% of projects are not to pay a contribution per Board Directive 13A in Decision 2005-056, and further described below) – the number of customers that would be required to pay a contribution would increase. But as noted the investment level is required to meet the criterion that 80% of projects do not pay a contribution. If the O&M charge was to continue to be applied to standard facilities, the cost function would increase but so would the investment level function so as to maintain the target of 80% of projects not having to pay a customer contribution. As such, the AESO is of the view that the benefit to economic siting and facility development originally intended by the Board by including the O&M charge is very limited.(Emphasis added).324

The Board considers that the concern discussed by the AESO in the emphasized portion of the passage above applies to all interconnection project costs. That is, if increasing interconnection project costs are, in the normal course, constantly updated within the maximum investment allowance to reflect an 80/20 rule, the ability of the maximum investment function to provide an economic signal may be significantly diminished over time.

Accordingly, while the Board has assessed how the 80% of projects threshold specified in Directive 13A impacts the multiplier and resulting maximum investment allowance, for the reasons discussed above, the Board’s statements in Decision 2005-096 do not constitute an endorsement by the Board of an 80/20 rule. Rather, the Board’s statements in that decision were intended simply to direct the AESO to conduct a study to determine a multiplier. A determination would then be made on whether or not use of that multiplier was warranted.

The Board provides its analysis and findings on the determination of an appropriate 2007 tariff investment function multiplier in the immediately following section.

8.1.2.2 Appropriate Multiplier for 2007 Tariff Maximum Investment Function

In determining the appropriate multiplier to apply to the approved POD cost function, the Board evaluated a rounded off version of the AESO proposed multiplier of 1.15149, namely 1.15, and developed cost functions in 0.05 multiplier increments until such time as 80% of the 48 point dataset projects would receive full investment. 80% of the 48 point TFO project cost data points received full investment using a multiplier of 1.35 applied to the Board approved cost function. A graph of the investment functions based on this data, including the AESO’s final proposed investment function, is shown below:

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324 Ex. 007, p. 14 of 47
In determining the impact that outlying data points have on the level of the multiplier required to satisfy an 80/20 rule, the Board analyzed the 48 point dataset to determine how many data points would receive at least 80% investment using the rounded version (1.15) of the AESO’s proposed multiplier of 1.15149.

A multiplier of 1.15 results in 27 data points receiving full investment, six data points receiving over 90% investment, and another five data points receiving at least 80% investment. As such, 38 out of 48 data points, or 79.2% of the data points receive at least 80% investment and the majority of these points receive full investment.

The above graph shows the raw data points that received at least 80% investment using the Board approved cost function and a 1.15 multiplier to determine the maximum investment function. These data points are marked with a + sign and noted in the graph legend.

The Board considers that using a 1.15 multiplier is more than adequate in providing a sufficient investment level of investment based on the 48 point sample dataset. This multiplier works just as well if a 30 point “greenfield” subset of the 48 point dataset is considered. Further, the 1.15 multiplier was also proposed by the AESO even after it modified its cost function in argument.

As the AESO obtains new TFO project cost information in the future, the 48 point dataset may be expanded and cost functions further analyzed. The key though is that any future changes to the investment function be based on actual project costs, without the potential circular bias that implementing and maintaining an 80/20 rule may impose. The Board observes that the 1.15 multiplier, when applied to the Board approved cost function, achieves a result that is not substantially different than the result that would be produced by application of an 80/20 rule. To
be clear, an 80/20 rule is not to be relied on in future when amending the maximum investment policy.

For all of the above reasons, the Board approves a multiplier of 1.15 to be applied to the cost function approved in section 5.7.7 of this Decision to determine the maximum investment function.

The resulting Board approved maximum investment function is as follows:

\[ Y = 1028 \text{ million} + 578 \text{ million/MW for the first 7.5MW} + 200 \text{ million/MW for the next 9.5MW} + 118 \text{ million/MW for the next 23MW} + 62 \text{ million/MW for all MW above 40.0MW} \]

The cost function approved in section 5.7.7 of this Decision entails rounding such that a pure application of the 1.15 multiplier may result in a difference in the third decimal in the above function. The function above has been determined by multiplying the unrounded Board approved cost function by 1.15, and then round the values to three decimals, and is the function to be implemented by the AESO.

8.1.3 Inflation Adjustments to Maximum Investment Function

TCE argued that although the AESO witness panel had confirmed that the investment levels set out in Article 9.6 were designed so that about 20% of DTS customers who attach to the system will make a contribution,\(^\text{325}\) it also confirmed that as the costs of projects rises overtime, on average more than 20% of customers would be required to make a contribution.\(^\text{326}\) In recognition of the effect of inflation, TCE submitted that the Board should direct the AESO to amend Article 9.6 of the T&Cs to include a project inflation factor such as the Consumer Price Index (CPI) or another widely recognized factor.

With respect to TCE’s proposal, the AESO noted that while it had agreed that a project inflation factor could be considered if an appropriate index could be used, the contribution policy in place at a given time should provide a price signal that reflects the current economic situation. The AESO submitted that the contribution policy should not be static, but should rather be revisited as more data becomes available.

DUC argued that the maximum investment allowance levels provided under the AESO’s contribution policy should be increased by 5% to reflect inflation over the period of late 2007, 2008, and 2009 that the AESO’s 2007 tariff may be in effect.

The AESO replied that the 5% increase proposed by DUC did not appear to be based on any trending analysis or inflationary economic reporting. The AESO further noted that an inflation rate based on Alberta CPI approved by the Board in other decisions was used to update POD cost data within the customer contribution study provided as Appendix F to the Application.\(^\text{327}\)

\(^{325}\) Tr. Vol. 2, p. 501, referenced at p. 64 of TCE Argument
\(^{326}\) Tr. Vol. 2, p. 502, referenced at p. 64 of TCE Argument
\(^{327}\) Ex. 015, referenced at p. 34 of AESO Reply
As discussed in section 8.1.2.1 above, the Board has not endorsed the so-called 80/20 rule. Accordingly, the Board rejects TCE’s proposition that that Article 9.6 should be amended to include an inflation allowance to maintain adherence to an 80/20 criterion.

The Board agrees with the AESO that DUC’s proposal for a 5% inflation adjustment is not necessary in light of consideration of the inflation adjustments applied to POD cost data as part of the AESO’s customer contribution study. The Board considers that as the average POD cost function adopted by the Board in this Decision already reflects inflation adjusted POD cost data, no further adjustments are necessary to bring the data up to date. The Board also agrees with the AESO that little basis was provided by DUC to support the selection of 5% as an appropriate inflation adjustment.

The Board disagrees with DUC’s view that an additional inflation adjustment is necessary to reflect the anticipated continuation of the 2007 AESO tariff into 2008 and 2009. The maximum investment function set out in section 8.1.2.2 of this Decision is significantly above the maximum investment allowance set out in Decision 2005-096. The Board considers that the increase in the level of the maximum investment allowances, particularly for AESO customers with a large contract capacity, offsets the impact of inflation on the cost of new interconnections.

The Board agrees with the AESO that that the effects of inflation on POD costs may be relevant to the reconsideration of maximum investment levels in the future. Such consideration should occur, if necessary, in the context of a future GTA.

8.1.4 Applicable Tariff for Customer Contributions and Contract Capacity Increases

In section 6.5.1 of the Application, the AESO described its proposed changes to Articles 9.2, 9.7, and 9.9 of its T&Cs. The AESO noted that its practice has been to recalculate the customer contribution for an interconnection project on the basis of the tariff in effect at the time the original interconnection was constructed.

The AESO submitted that it was appropriate to revise the amounts of customer contributions based on the contribution policy in effect at the time of the original system access request because the events described in Article 9.9 and the sharing of facilities discussed in Article 9.10 of the T&Cs are largely outside the control of the customer and primarily affect the original facilities built to accommodate the original system access request. However, the AESO acknowledged that it had also encountered situations where a customer request for an increase in contract capacity required the construction of new transmission facilities to accommodate the contract capacity increase. The AESO noted that this situation was not currently explicitly addressed in the T&Cs, but that it was the AESO’s business practice to apply the approved tariff in effect at the time of project commitment to determine the customer contribution and contract term. In light of this practice, the AESO proposed updates to Article 9.2, 9.7, and 9.9 to reflect this treatment.

No parties took issue in argument or reply with these changes as proposed by the AESO. The Board has reviewed Article 9.2, Article 9.7 and Article 9.9 and approves these provisions as filed.
8.2 ASES Standard Facilities

8.2.1 Matters Raised in Evidence of ATCO Electric

In its evidence, AE expressed a concern about the ASES’s interpretation of “standard facilities” in the context of the application of the ASES’s customer contribution policy. AE noted that in Decision 2001-6, the Board had stated that the total Alberta electric system should be planned with the appropriate mix of transmission and distribution facilities and that the contribution polices of various entities should work together so as not to disturb proper planning. AE also noted that Decision 2005-096 indicated that the primary focus of efforts to harmonize customer contribution policy matters between Discos and the ASES should be on harmonizing the definitions of “standard facilities” and “optional facilities.”

AE indicated that it had expressed concern in discussions with the ASES regarding the commercial treatment of certain projects. AE submitted that the best way to uphold a principle that the ASES and Disco contribution policies not disturb proper planning is to ensure that the commercial determination of standard facilities supports the best overall planning solution. To illustrate its concerns, AE provided two examples of projects in which it considered that the AESO’s commercial determination of standard facilities had frustrated proper planning efforts.

AE submitted that as regulated entity it can and will take into account the greater public interest when making decisions regarding the evolution of the electric system (including consideration of the cost of losses, reliability, power quality, motor starting capability, and voltage support). However, AE submitted that as customers making decisions about transmission connection and distribution connection would not take such matters into account, the ASES’s definition of standard facilities must take into account the optimal solution for the integrated electric system, and not simply the solution that minimizes the currently forecast transmission costs.

The ASES submitted a supplemental filing to the Application on May 1, 2007 which, among other things, proposed revisions to Article 9.1 of the T&Cs (added words underlined):

In considering requests to provide service to a new POC, or to increase the capacity of or improve the service to an existing POC, the ASES will determine the appropriate means of delivering the requested service.

(a) If the Customer’s request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension (“the project”)

(b) If the ASES determines that the viable and most economic option for providing service to a Customer includes a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then:

(i) for the purposes of determining the Local Investment in Articles 9.3 to 9.6, the project costs referenced in Article 9.3 will include only the costs of the transmission facilities required in the most economic service option (if any);

(ii) and if the customer selects a transmission facility instead of the one determined by the ASES to be viable and the most economic, then the

328 Ex 223
329 Ex 223, pp. 3-11 (Updike 144 kV line and substation, and a potential connection of two oilsands developments)
330 Ex. 349
customer will pay the cost of the transmission facility less the Local Investment as calculated in accordance with part (i) above.

In its rebuttal evidence, the AESO noted that it was engaged in ongoing discussions with its customers (including AE) regarding its interpretation of AESO standard facilities as part of its compliance with the Board’s harmonization direction from Decision 2005-096. It also presented a revised proposal regarding the Updike project that had been raised by AE.

Given the AESO’s rebuttal evidence, AE indicated in argument that it and the AESO were able to reach a mutually acceptable commercial solution on the most pressing matter that AE had raised, and made considerable progress on the other matter. As such, AE stated that, the Board’s intervention was not required to appropriately address the matters raised in its evidence.

However, AE requested that the Board consider confirming in its Decision that while the AESO should be afforded discretion in determining of what constitutes AESO standard facilities in specific instances, the AESO should apply its investment policy in a manner that ensures that the most appropriate facilities are built. AE submitted that the determination of the most appropriate facilities should uphold the principles of good transmission and distribution practice and should give due consideration to all aspects of electric system planning (including reliability, power quality, protection, distribution and transmission losses, maintenance practices, and operating criteria and standards).

It remained AE’s view that certain additional language (described in its response to BR.AE-003) should be inserted into the definition of AESO standard facilities and into Article 9.13 of the AESO T&Cs. In reply argument, the AESO indicated that it would not take issue with AE’s proposed changes to the AESO standard facilities definition and Article 9.13, if so directed by the Board.

In reply, IPPCA expressed concern that the AESO and AE appeared to have agreed that a larger transmission capital investment should be made to avoid losses on the distribution system, yet the higher transmission capital expenditures made no mention of a higher contribution by the Disco. IPPCA also expressed concern with the characterization of the issue as a commercial matter between parties. IPPCA submitted that the apparent understanding between the AESO and AE had the potential to cause significant transmission investment to offset distribution losses. As it did not appear that reduced losses would receive the same consideration with respect to sites of transmission connected industrial customers, IPCAA submitted that the AESO’s proposed arrangement would not provide equitable treatment between transmission connected and distribution connected loads.

Both the AESO and AE proposed certain changes to the AESO tariff T&Cs to address AESO standard facilities issues raised in AE’s evidence. The core proposition in AE’s evidence is that customer contributions arising from the determination of AESO standard facilities can, in some instances, disrupt optimal planning processes by influencing the mix of transmission and distribution facilities built for specific projects. The Board does not agree.

331 Ex. 347
332 Decision 2005-096, p. 73
333 Ex. 292
The Board considers it important to look at the circumstances of both a direct-connect customer and a Disco that is deciding how to provide service to a new end-use customer or to accommodate load growth within its service territory. There is generally no need for a Disco to consult with the AESO when one of its prospective or existing end-use customers requires new or expanded interconnection facilities, unless and until the Disco determines that some additional DTS contract capacity and associated transmission facilities may be required to accommodate the requirements of the Disco’s end-use customer or growth within the Disco’s system. It is only at this point that the AESO becomes involved in assessing the requirements of the end-use customer (with the advice and assistance of the Disco) to determine the appropriate amount or increment of DTS capacity that the Disco would be required to contract for in respect of a new or expanded AESO POD. If it is subsequently determined that additional transmission facilities will be required, the Board understands that the Disco and the AESO collaborate to prepare an application pursuant to section 34 of the EUA. Pursuant to section 34 of the EUA, that application is prepared and submitted by the AESO.

In its response to AE.AESO-003, the AESO provided hyperlinks to eight separate process guidelines related to distribution point of delivery interconnection process guidelines. These documents were prepared by the AESO with assistance from Alberta Discos and TFOs. Furthermore, while the Board will not comment on the specific content of the documents, for the purposes of this proceeding, it is apparent that they are comprehensive and detailed and that they were prepared for the express purpose of determining the appropriate set of facilities to be used in the circumstances contemplated.

The following two paragraphs appear in each of the eight guidelines:

This guideline is intended solely for the purpose of supporting the AESO’s customer interconnection process to arrive at proposed interconnection concepts that are optimized on a technical and economic basis. It will not in any way address or determine the AESO’s facility cost allocation between system and customer, nor will it be used in any way as a guideline in applying the AESO approved tariffs and investment policy.

This guideline is intended to facilitate documentation of the project need and the evaluation done to support the need, in alignment with the interconnection process. The interconnection process has a requirement for AESO endorsement and AEUB approval of the project need. (Emphasis added)

The above paragraphs reflect that the decision making process respecting new POD interconnections is focused on achieving an optimal technical and economic solution, and that these considerations are to ultimately be reflected in need applications. Given this, the Board considers there is no basis on which to expect that the transmission facilities built following the approval of a section 34 application would not reflect the optimal combination of transmission and distribution facilities required to serve the end-use customer of the distribution system owner. Accordingly, it is not apparent to the Board that an AESO tariff proceeding is the appropriate forum in which to address the concerns identified in AE’s evidence.

334 Ex. 098
335 Ex. 098, AESO.AE-3, pp. 2-3, Tr 847
336 Ex. H-002, p. 1
337 Ex. H-002, p. 1
Nevertheless, within the context of the AESO’s tariff, the Board considers that an important principle is that Discos and AESO direct connect customers be afforded comparable treatment under the AESO’s customer contribution policy. Comparable treatment will generally be achieved if the cost of AESO standard facilities is determined in a manner that reflects the capacity of the actual transmission facilities built in accordance with the section 34 application (approved by the Board) and in a manner that is consistent, as between Discos and direct connect customers. Therefore, the Board considers that, all other things being equal, the general principle should be whether a DTS contract capacity increase is requested by direct connect customer of the AESO or by a Disco, the resulting facilities determined to be needed should be the same, reflecting the one line, one transformer AESO standard facilities definition. Given the Board’s affirmation of comparable treatment of direct connect customers and Discos, the concern raised by IPCAA regarding possible inequitable treatment as between transmission connected and distribution connected loads does not arise.

The Board considers that to the extent that AE’s issues are tariff related, the appropriate forum in which to address these concerns are in the Disco tariff proceedings, and not in the AESO’s tariff proceeding. The extent of the Disco’s ability to pass through optional facility costs (as determined by the AESO applying its tariff) depends on the Disco’s tariff and the contribution policy contained in that tariff. Thus, the Disco remains responsible for ensuring the reasonableness of all of its revenue requirement components. As such, the Disco may bear some risk that the full amount of a customer contribution assessed by the AESO may not be fully recoverable through the Disco’s tariff. This may for example arise if the Disco for some reason has not acted reasonably, such as by having requested AESO optional facilities on behalf of its end-use customer in the context of the section 34 application process, but then is subsequently unable to pass on to its customer the full amount of the costs of the facilities that exceed AESO standard facilities, for example if its own contribution and investment policies do not permit such costs to be passed on to its customer and the Board denies any proposed inclusion in the Disco’s revenue requirement.

For the purpose of this Decision, as long as a Disco has complied with the AESO’s interconnection guidelines, its own tariff, and has acted reasonably and prudently incurred the costs, the Board considers that there would be only minimal risk to the Disco of disallowance of contributions paid to the AESO. However, such risk on the Disco may arise if the Disco pursues transmission facilities inconsistent with the interconnection process guidelines either on its own initiative or at the request of its end-use customer. The reasonableness of Disco expenses is, of course, assessed in Disco tariff proceedings.

In light of these findings, the Board approves the AESO’s standard facilities definition and related T&Cs as initially proposed by the AESO in the Application but not the amendments subsequently proposed by the AESO in its supplemental filing. Furthermore, as the issues raised by AE in the current proceeding relate to EUA section 34 processes and not tariff matters, the Board is not prepared to comment on any arrangement or accommodation that may or may not have been reached between the AESO and AE in respect of issues raised by AE in this proceeding.
8.2.2 Transmission vs. Distribution Service and Required Use of Variable Frequency Drives

The PPGA expressed concern about the process followed by the AESO to determine whether “standard facilities” should encompass a transmission or a distribution connection. The PPGA considered the process to be unclear and unsystematic, and submitted that the Board should direct the AESO to clarify this process. The PPGA submitted that the AESO should standardize the flicker limit test used to determine “standard facilities” to be based upon 3 times in-rush, or a typical soft-start mechanism – as opposed to a VFD (unless the customer agrees to install a VFD). The PPGA considered that this would ensure that the test is fair and that customers are not directed to implement an AESO initiated VFD to accommodate motor starting.

The AESO argued that although it maintains a clear policy on flicker limits for the transmission system, flicker limits on the distribution system are set not by the AESO, but by the Discos, based on industry standards. The AESO submitted that the flicker limit standards of the Discos have been in place for some time, and have not changed in recent years. In its rebuttal evidence, the AESO stated that in some circumstances, local conditions on a distribution feeder may cause the Disco to apply more stringent measures. The AESO submitted that to direct either the AESO or Discos to follow any other methodology regarding flicker limits would be contrary to good industry practice.

The AESO also pointed out that the determination of standard facilities is used to assist the AESO with decisions on customer contribution levels; it does not limit the customer’s selection of a transmission or distribution option.

The AESO’s Distribution Point-of-Delivery Interconnection Process Guideline: Evaluation of Transmission versus Distribution Alternatives for Large Customers states that the Disco will ensure that the voltage fluctuation associated with motor starting by one customer does not create problems for other customers. This guideline states that voltage fluctuation during motor starting is not to exceed the Disco’s standards for fluctuation as specified in the AESO Interconnection Process Guide, Standards of Service. To determine the significance of an impact the motor starting will have on the distribution system, the Disco models the typical characteristics of the motor to determine what limit on inrush current is necessary to limit the voltage fluctuation to the Disco’s standard. The guideline goes on to state that when the voltage fluctuation is greater than the Disco’s standard, voltage reduction and inrush current limiting techniques are evaluated such as the use of an autotransformer or a VFD.

If voltage reduction techniques do not appear promising, then distribution system improvements are to be evaluated. In lieu of installing motor starting aids, certain alternatives are to be investigated. This guideline recognizes that each Disco has different voltage fluctuation guidelines.

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339 Ex. 240, PPGA Transmission vs. Distribution evidence
340 AESO Reply Argument, pp. 35-36; Ex. 347 AESO Rebuttal Evidence pp. 11-15
The Distribution Point-of-Delivery Interconnection Process Guideline - Standards of Service simply summarize the standards that each Disco applies to its distribution system with respect to the allowable voltage fluctuations/flicker. The Board notes that the standards applied by the Discos are not uniformly consistent.

The Board understands that both of these guidelines were developed by the AESO with the involvement of Discos.

No evidence was submitted in this proceeding of an AESO requirement that a VFD would be required to accommodate motor starting on the distribution system. Based on the evidence in this proceeding, the Board agrees with the AESO, that flicker limits on the distribution system are within the purview of the Discos. The Board considers that the decision to provide transmission or distribution facilities in the circumstances of specific customers must be evaluated separately for customers of the AESO and customers of Discos. Accordingly, the Board will not direct the AESO to amend the interconnection process guidelines. In general, to the extent that PPGA, any specific member thereof, or an end use customer of a Disco, has concerns with technical standards established by a Disco, those concerns should be addressed directly with the Disco and if any irresolvable concerns remain they may be pursued in a relevant Board proceeding relating to the relevant Disco.

8.3 Prepaid O&M Charge

In the Application, the AESO described its proposed changes to Article 9.4 of its T&Cs. The AESO noted that although the Board had determined in Decision 2005-096 that a charge based on 12% of the cost of the both standard and optional facilities for a customer interconnection, the AESO proposed to amend the prepaid O&M charge to reflect only the cost of any optional facilities built for a new customer interconnection.

The AESO noted that a proposal in the AESO’s prior GTA to apply a prepaid O&M charge only on the optional portion of an interconnection project was rejected by the Board in Decision 2005-096. However, the AESO suggested that the Board’s prior decision should be reconsidered because the Board’s rationale for varying the AESO’s original proposal in Decision 2005-096 did not take into account the impact of the ongoing re-assessment of the maximum investment function caused by applying the “80/20” rule.

The AESO also expressed concerns that applying a prepaid O&M charge on standard facilities would require new procedures and processes to ensure O&M costs are being recovered correctly and are not recovered in other components of the TFOs revenue requirement. In addition, the AESO expressed concerns that applying a prepaid O&M charge to standard facilities could compromise harmonization efforts between the AESO and the Discos, since Discos include an O&M charge only on optional facilities. The AESO also submitted that its proposal would be beneficial because it would avoid intergenerational inequity, reduce tariff complexity and would

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343 Ex. 098, AESO AE-3, pages 2-3 of 4; Tr 847
344 Ex. 007, Application Section 6.5.2, pp. 13-15
345 Ex. 007, p. 14 of 47
respond to the concerns of stakeholders who had opposed the charge during stakeholder consultations.

The AESO argued that applying an O&M charge for facilities in excess of standard would send an appropriate price signal to customers that their postage stamp rate reflects only costs associated with the standard level of service provided by the AESO. The AESO noted that because O&M costs associated with standard service are properly recovered through average rates, it is not necessary to include an O&M amount as part of the customer related cost of standard facilities used to determine the contribution.

TCE indicated in its argument that it was in agreement with the AESO’s proposed treatment of prepaid O&M.

The Board reiterates that it considers that it is appropriate to send economic signals to AESO customers that appropriately reflect the cost causation consequences of a customer’s decisions.

No evidence was filed indicating that additions of new customer PODs or expansions to existing PODs do not generate some level of incremental TFO O&M costs above and beyond the incremental capital costs of new interconnection facilities. In the absence of such evidence, the Board considers that projected incremental TFO O&M costs should be reflected in the AESO’s customer contribution policy.

While the Board agrees with the AESO that a signal reflecting incremental TFO O&M costs should be provided to customers seeking new or expanded interconnections, the Board does not agree with the AESO’s proposal to provide this signal only in respect of the “optional” portion of an interconnection project. To the extent that the incremental capital costs of a new interconnection are at least proportionally related to incremental TFO O&M costs, it would be inappropriate to effectively confine this relationship to the optional portion of facility capital costs. If TFO O&M costs are related to facility capital costs, it does not follow that an estimate of incremental TFO O&M costs for the purpose of the economic signal should be generated only by the optional component of capital cost.

It also follows that at the time an estimate of the incremental TFO O&M costs is provided, any amount of the incremental TFO O&M costs deemed to be related to the optional portion of the new interconnections should be borne entirely by the interconnecting customer. This is the effect of Article 9.4 as currently approved. Furthermore, the Board considers that the estimated increment of TFO O&M cost related to constructing standard facilities should be evaluated against the maximum investment allowance established by the Board. Again, this treatment is accommodated in the currently approved wording of Article 9.4. As discussed in section 8.1.2.2, the maximum investment allowances approved in this Decision are larger than those approved in Decision 2005-096.

Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO’s 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO’s advancement of the cost study used in support of the AESO’s revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, $0.12 of incremental TFO O&M costs will be generated by each $1.00 of capital investment in an interconnection facility. However, additional research into
the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA.

In light of the above, the Board finds that the wording of Article 9.4 as approved in Order U2005-464 remains for the most part appropriate. However, to avoid potential confusion arising from the use of the word “prepaid”, the Board directs the AESO to amend Article 9.4 as indicated below, and to include this revised wording for Article 9.4 in updated T&Cs to be provided with the AESO’s filing application:

9.4 Operations and Maintenance
For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of:
(a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and
(b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

8.4 Staged Contracts and Payments of Related Contributions
In the Application the AESO proposed to amend section 9.7 of the T&C to provide that when a customer requests an increase in contract capacity which requires the construction of new transmission facilities, the approved tariff at the time of project commitment for the new contract capacity request is to be used to determine the customer contribution and contract term. The AESO submitted that these constitute new commercial decisions which therefore required a new commercial arrangement. It considered that in such circumstances, the customer contribution calculation in the tariff in place at the time of the request for additional capacity should be applied. While parties did not question this proposed amendment, they did question the AESO’s policy of collecting a customer contribution at the signing of the original request for service for all future staged loads.

In argument TCE stated that the AESO currently requires a generator to pay the entire cost of the customer contribution for an interconnection close to when a request is initially made and sometimes well ahead of when the costs are actually incurred. TCE argued that this may discourage construction of additional generation in Alberta. TCE noted that when questioned by the Board about the need to receive a full customer contribution, where millions of dollars can be required years in advance, the AESO provided what appeared to be two reasons: financial security and a demonstration of commitment. TCE believed that each of these concerns could easily be dealt with through financial assurances and appropriate agreements. Alternatively, TCE submitted that contributions should be placed in an account (incurring interest) and drawn down as the project proceeds.

EPCOR argued that staged contribution payments will provide a sharper and more precise economic signal. It argued that this would conform to one of the purposes of the EUA, which is

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346 Tr. Vol. 2, p. 348, line 18 to p. 349, line 2, p. 360, line 20 to p. 367, line 1
347 Tr. Vol. 4, p. 861, line 13
348 Tr. Vol. 4, p. 864, lines 2-9
to “continue a flexible framework so that decisions of the electric industry about the need for and investment in generation of electricity are guided by competitive market forces.”

EPCOR maintained that imposing a tariff requirement that all potential interconnection costs must be paid upfront creates an unnecessary drain on scarce capital during the development phase of a new unit. There was no compelling reason for the AESO to increase capital demands on generators in a competitive industry in a manner which loosens, rather than tightens, the link between the principles of cost causation and fair cost recovery. EPCOR submitted that Article 9 would be enhanced by allowing contribution payments to match actual expenditures where economically efficient to do so, provided that the AESO may require reasonable financial assurances to backstop any expenditure it is called upon to make. These assurances would be in the nature of letters of credit or the credit rating of the requesting customer or any other agreed upon financial assurances.

EPCOR submitted that subsection 29(3)(e) of the 2007 Transmission Regulation dealt with the fixed charges for transmission system upgrades, not local interconnection costs, which are dealt with under section 28 of the 2007 Transmission Regulation. EPCOR proposed that if the generator does not require a stand alone local interconnection facility (for example switch gear) for a period of several years, payment should be delayed until the actual commencement of construction of this particular local interconnection facility.

EnCana recommended that the Board direct the AESO to discharge the contribution policy in a manner that fosters the lowest cost development of the transmission system.

EnCana suggested that the AESO’s approach is problematic and does not foster the lowest cost development of the transmission system. It pointed out that a customer that makes the cash payment is not compelled to proceed with a second or subsequent stage of expansion and therefore there is no guarantee that the staged costs will be required or incurred. Even if the customer had made a cash payment for the full construction, the cash payment does not encourage a customer’s commitment to subsequent stages because any such payment is fully refundable if the facility costs are not incurred. In the meantime, the customer has lost the opportunity to use the funds in an otherwise productive fashion.

The AESO argued, as it had previously stated, that it is often more economic to construct all the interconnection facilities required to accommodate all the contracted capacity increases at once, rather than over a period of time. If it was determined to be economically beneficial to build all the facilities to accommodate all present and future contracted capacity at once, the customer contribution for the entire project would be collected prior to construction. The AESO maintained collecting all customer contributions at the time of the initial contract is consistent with historical practices that date back to the tariffs of the AESO’s predecessors. It also considered that the current practice maintains harmonization with Disco tariffs and ensures customers - whether they are receiving service from the Disco or the AESO - are being treated equitably.

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349 Electric Utilities Act, Section 5
350 Article 9.8(c) and 9.9(f)
351 Ex. 110, EPCOR.AESO-001 (a-c)
The AESO submitted the practice of collecting contributions prior to construction has been reinforced in subsection 29(3)(e) of the 2007 *Transmission Regulation*.\(^{352}\) Sections 28 and 29 of the regulation read, in part, as follows:

28(1) The ISO must include in the ISO tariff

(a) local interconnection costs, as defined by the ISO, payable by an owner of a generating unit for connecting to the transmission system,

(b) the terms and conditions, and

(c) provisions for the recovery of local interconnection costs from owners of generating units.

(2) The ISO must make reasonable efforts to ensure that the interconnection of a generating unit to the transmission system is undertaken in a timely manner.

(3) The owner of a generating unit that interconnects with the transmission system, and who has paid local interconnection costs, may not prohibit interconnection or access to the interconnection facilities by other market participants.

…

29(1) The ISO must include in the ISO tariff

(a) the amount, determined under subsections (2) and (3), payable by an owner of a generating unit to the ISO, and

(b) terms and conditions related to clause (a).

(2) The amount payable by owners of generating units is the sum of the following:

(a) for upgrades to existing transmission facilities, a charge of $10 000/MW;

(b) a charge of not more than $40 000/MW, as provided in the ISO tariff, payable by owners of generating units that locate in an area of the transmission system where generation exceeds load, and the amount of the charge is to be determined based on the location of the generating unit relative to load.

(3) A charge under subsection (2)(b) may be revised from time to time, but must

…

(e) be determined and payable in accordance with the ISO rules and the ISO tariff, be paid before commencement of construction of the local interconnection facility and be paid once only for that specific location and generating unit

…

\(^{352}\) Transmission Regulation, 29 (3) (e)
Interveners argued that section 29 of the 2007 *Transmission Regulation* applied to system upgrades, not to local interconnection costs. They maintained that section 28 governed the collection of costs for the interconnection of generation facilities.

The AESO stated that the payment of the customer contribution has two primary benefits: providing a solid form of financial security for the construction of transmission facilities, and a meaningful demonstration of commitment from the customer. In addition, it offset the TFO’s working capital, which is beneficial to all ratepayers.

Regarding the suggestions of EPCOR and TCE that providing a letter of credit or some other financial instrument be provided as a form of financial security, the AESO submitted that once the permit and license for an interconnection facility has been approved by the EUB and construction is about to commence, the concept of the customer contribution changes from being simply security to prepayment for service. Also, the AESO submitted that collection of cash contributions are a stronger form of security than a letter of credit when facilities are being purchased and constructed.

Lastly, the AESO noted that if the customer is concerned that future stages of the project may not proceed, or there are other financial considerations which impact their ability to pay the customer contribution associated with future capacity requirements, the customer can choose to simply contract for the first stage of their project and sign up for other phases in the future. The customer is then sending a clear signal to the AESO on the expected load requirements necessary for system development and the customer has the ability to manage their financial obligations associated with their project and interconnection to the AIES.

The Board considers there are two possible scenarios in relation to this issue. The first scenario is where the customer identifies all contemplated future expansion plans to the AESO, the AESO determines it is most economical to construct all facilities at once, and the facilities are constructed at the time of the initial contract. Should the customers’ circumstances change in the future and a capacity increase be requested it would be treated as a separate project.

In this case the Board considers it reasonable to collect the entire customer contribution at the time of the initial contract. The Board appreciates that while the customer will be required to pay for facilities upfront which may not yet be required, this cost may be offset by potential cost savings that result from constructing all of the facilities at the same time. Consequent savings in the customer contribution may generally offset the increased carrying cost to the customer. If the customer requiring the facilities did not pay the contribution upfront then other customers would be in the position of cross subsidizing the customer requesting the facilities. The Board considers that such cross-subsidization would be an unfair result.

The second scenario is where the customer identifies future requirements to the AESO but the facilities for such requirements can be deferred until the time the customer contracts for the additional required capacity at a future point in time. The AESO considers that the customer contribution should be paid at the time of the initial contract in these cases as well.

Interveners generally argued that supplying letters of credit or other such financial assurances from customers would provide the necessary demonstration of commitment and financial security required.
The Board has reviewed sections 28 and 29 of the 2007 Transmission Regulation and agrees with interveners that section 29 relates only to system upgrades. Section 28(1)(a) refers to local interconnection costs while section 29(2)(a) refers to upgrades to existing transmission facilities. The Board finds that section 29 is referring to system facilities that must be enhanced to accommodate additional generation. Section 28 is therefore the provision that is applicable. Unlike section 29, section 28 does not require the charge to be paid before commencement of construction. The Board therefore considers that section 28 allows the discretion to collect costs related to a local Point of connection (POC) on a staged basis.

The Board also agrees with the parties that allowing staged contributions for future capacity requirements would prevent a drain on scarce capital and is more in keeping with cost causation. The potential exists that supplying a letters of credit or other such financial assurance from a customer, should the customer be deemed to be credit worthy, may provide the necessary demonstration of commitment and financial security required by the AESO. The Board also considers TCE’s suggestion that such funds be deposited in an interest bearing account to have merit.

While the Board believes that the adoption of staged payments is directionally appropriate, the Board is not convinced that sufficient evidence has been gathered to determine the extent to which letters of credit may or may not provide sufficient strength of financial security, the terms that any such letters of credit should involve, the nature and extent of other financial instruments that may be warranted, or what other measures may be warranted. Nor is the Board convinced that sufficient evidence has been gathered on the construction or other milestones at which staged payments should be made. Accordingly, the Board directs the AESO to conduct further analysis of the nature, amounts and milestones at which staged payments should be made, conduct such stakeholder consultations as it considers appropriate, and propose a tariff provision permitting staged contribution payments no later than the AESO’s 2009 GTA or, if no such application is made, in its next GTA thereafter.

Given the above, the Board approves the AESO’s proposed revisions to sections 9.2 and 9.7 of its T&Cs as reflected in the Application for purposes of this decision.

8.5 Contract Capacity Increases and Allocation

In the Application, the AESO stated that during the AESO’s stakeholder consultation process for the 2007 GTA, it had initially proposed a number of revisions to Article 13 to align AESO business practices with the tariff. It also undertook an additional stakeholder consultation process relating to business practices in respect of interconnection queue management and compliance milestones which may have an impact on Article 13. As such, the AESO proposed only two minor revisions to Article 13 at this time, to clarify:

1) a notice requirement for customers requesting an increase of their contract capacity at an existing POD or POS such that the notice must be in writing, and

2) that increases will be effective upon execution of the system access service agreement assuming sufficient transmission capacity can accommodate the requested contract capacity increase.

No objections to these proposed changes were received. The Board accepts the proposed changes as reasonable and they are approved as filed.
8.6 Reductions or Termination of Contract Capacity / Payments in Lieu of Notice

Article 14 of the AESO’s T&Cs contains provisions regarding reductions in system access service contract levels and terminations of system access service. In the Application, the AESO proposed changes to Article 14 to revise the manner in which lump sum payments in lieu of notice (PILONs) are determined for customers wishing to either reduce the capacity level of their system access service contracts or completely terminate those contracts.

The AESO stated that it had proposed changes to Article 14 to:

- clarify the details of how lump sum payments for contract level reductions or system access service terminations should be calculated;
- ensure that lump sum payments include the system charge but exclude the DTS POD charge;
- prescribe the use of the discount rate outlined in Article 9.14 of the T&Cs;
- clarify the prerogative of the AESO to revisit and revise the calculation of lump sum payment amounts in the event of material differences between requested contract and actual contract capacity.

The AESO submitted that its proposal to exclude the POD charge portion of the DTS rate when calculating a lump sum contract reduction or termination payment reflects the fact that the POD related portion of the charge is effectively captured by Article 9.9 of the T&Cs. Article 9.9 provides for a recalculation of customer contributions if a material change occurs in contract capacity. The AESO also noted that as the principles, rationale and importance of the five-year notice period endorsed in Decision 2005-096 continued to be reasonable, the AESO had not changed this requirement.

The evidence of Dr. Rosenberg on behalf of the ADC expressed concern about the AESO’s proposed payment in lieu of notice provisions. Dr. Rosenberg was opposed to exit fees in principle for several reasons. The concerns he expressed included (1) that such payments would not exist if transmission was provided as a competitive service since customers would not consent to bind themselves contractually; (2) unlike POD costs, bulk system and local system costs do not become stranded because new customers will use any capacity made available by a customer’s exit; and (3) as a practical matter, it is difficult to estimate what the billing determinants of the exiting customer would have been if the customer had remained on the system.

Dr. Rosenberg suggested that a five year notice period would not likely assist planning since if an industrial customer finds it needs to shut down its operations for financial reasons, it will not know this five years in advance. Instead, Dr. Rosenberg suggested that it would be of greater assistance to the AESO’s planning process to require that customers provide a good faith forecast of future service requirements.

The AESO, ADC, ASBG/PGA, DUC and CCA/PICA all presented arguments on payment in lieu of notice provisions. The views of parties in respect of payments arising from system access

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353 Ex. 007, Section 6.7 of the Application, pp. 34-35
354 Ex. 221, pp. 43-46
service reductions or terminations can broadly be classified into (1) submissions on the theoretical appropriateness of exit fees; and (2) in the alternative, proposed refinements to the AESO’s tariff.

The primary theoretical arguments for or against exit fees primarily related to (1) the question of whether an exiting customer would, or would not be expected to create stranded costs; and (2) the question of whether the existence of exit fee provisions in the tariffs are of assistance to the AESO’s long term system planning efforts.

With respect to stranded costs, the Board agrees with the ADC that potential for stranded costs on the bulk and local systems may be lessened during periods of strong economic growth and/or during periods when the transmission system is in the midst of a major expansion phase. However, the Board also agrees with the view of CCA/PICA that regardless of either the state of the Alberta economy or the ambitiousness of the AESO’s transmission expansion plans, there can be no guarantee that system capacity released by a DTS customer will always, or necessarily even often, be replaced by another customer wishing to use that available system capacity within a reasonably short time. As a result, the Board considers that there will always be a potential that the exit of a customer will trigger stranded costs that must be borne by the AESO’s remaining customers.

The Board agrees with the AESO that the CCA/PICA proposal to further investigate the notion of capacity swaps is inconsistent with Alberta’s policy and legislative framework, which is not designed to reflect the notion of acquired capacity rights.

With respect to the question of the impact of exit fees on system planning, the Board disagrees with the ADC’s view that exit fees do not assist the AESO in conducting long term system planning. The ADC’s view does not take into account the problem of the free rider that may arise in any situation when the recovery of shared facility costs are widely disbursed among many customers. ADC’s view also fails to account for the fact that some customers may benefit from receiving additional capacity that may greatly exceed the expected share of incremental costs that they pay.

There is no specific requirement that load forecasts provided by DTS customers in accordance with Article 8.2 of the AESO’s T&Cs must correspond with the actual amount of capacity contracted for by DTS customers. However, the Board considers that the prospect of a customer being subject to an exit fee if it reduces its maximum DTS contract capacity or terminates its DTS contract emphasizes the importance of accurately forecasting the amount of contract capacity prior to making a capacity commitment. Thus, the amount of capacity contracted for by DTS customers at specific PODs is an important factor in system planning, the existence of exit fee provisions in the tariff generally has a positive effect on the accuracy of the AESO’s system planning efforts.

Based on the foregoing, the Board finds that an exit fee mechanism is beneficial and economically supportable. Consequently, the Board remains strongly of the view that the continued provision of economic signals through an exit fee mechanism remains a desirable and appropriate aspect of the AESO’s tariff.

The Board acknowledges DUC’s suggestion that the PILON charge ought to take into account both the demand and energy portions of the DTS rate, to reflect that the higher energy charge
component of the AESO DTS rate design was justified in part to reflect cost causation differences between high and low load factor customers. However, in light of the Board’s decision not to adopt the AESO’s proposed A&E method, this issue does not need to be considered in respect of the PILON charge. The fact the AESO’s proposed DTS rate design has not been approved also addresses the DUC proposal to base PILON charges on historical DTS billings that had occurred prior to the customer’s notice of contract reduction or termination. The Board does not agree with DUC’s proposal to reduce the number of years used to determine PILON charges from the current five years to two years.

The Board has not been persuaded at this time by the AESO’s proposal to eliminate the POD charge component from the determination of PILON charges. While the Board agrees that Article 9.9 of the T&Cs provides for a recalculation of customer contributions if DTS capacity is reduced, the AESO has not proposed to eliminate the POD charge portion of the DTS rate for a DTS customer who elects to continue to pay DTS rates rather than make a lump sum payment. However, the wording of Article 9.9 is not overly prescriptive as to how the exact amount of any revised customer contribution is to be calculated to reflect changes in a customer’s DTS contract capacity. Accordingly, if the AESO believes that continuing DTS charges could cause a double collection, the AESO may take this into account as appropriate into any calculations made in accordance with Article 9.9. As the AESO has included in its Article 14 PILON only the system charge portion and not the POD charge portion of the DTS rate, no additional Board direction is required.

Finally, the Board rejects the ADC’s proposal that if a customer chooses to manage a contract reduction or termination though the “ride out” option (by continuing to be subject to DTS charges for the five years following the provision of notice), that customer’s rates should be based on the DTS rates in effect at the time of notice. The Board finds this option to be unnecessary, since the customer’s risk of future DTS rate changes can be mitigated by selecting the lump sum PILON charge option.

8.7 Regulated Generating Unit Connection Charge

In section 6 of the Application, the AESO described its proposed revisions to Article 14 of its T&Cs to address the applicability of the regulated generating unit connection cost (RGUCC) component of the STS rate if a regulated generating unit (RGU) terminates its system access service contract prior to the expiry of the RGU’s base life as indicated in the tariff. This included a proposal to charge new generators an additional charge based on the replacement cost new (RCN) of the existing interconnection facilities previously used by a regulated generator that has ceased operations.

The AESO noted that prior Board decisions had established the RGUCC to establish a “level playing field” between the generators that were required to pay their own interconnection costs and the previously regulated generators (for which the interconnection costs were part of embedded transmission costs). However, the AESO considered that as and when a previously regulated generator no longer produced electric energy, the RGUCC no longer served any economic purpose. Accordingly, the AESO submitted that the RGUCC should not continue to

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355 The base lives of RGU’s are set out in the rate appendix of the AESO’s proposed tariff. See Ex. 008, pp. 50-52.
356 Citing Decisions 2000-1 and 2002-048
Alberta Electric System Operator

2010 ISO Tariff

December 22, 2010
Small Power Research and Development Act into Rate STS from its current location in Article 21.5 of the T&Cs to the applicable Rate STS subsection.

10 TERMS AND CONDITIONS OF SERVICE

10.1 Reorganization of Terms and Conditions of Service

327. The AESO submitted that the Application represented an evolution of the AESO’s current tariff, as developed for the 2007 test year and approved in Order U2008-217. The AESO noted that it reorganized the T&Cs to achieve standardization and consistency with the AESO’s other authoritative documents, in accordance with the principles and structure established under the AESO’s TOAD project. The reorganization has resulted in some content being added to the tariff, as well as some being removed from it. While the majority of these changes affect the T&Cs, certain changes such as those relating to demand opportunity service, have resulted in content being moved between the rates and T&Cs.

328. The AESO identified a number of aims for the TOAD initiative, namely to simplify and update the terms, to maintain a structure and approach that will be sustainable in the context of the AESO’s authoritative documents, and to provide stability and certainty for market participants.135 The AESO also proposed to restructure the T&Cs and to remove provisions where the relevant content was addressed in AESO technical requirements or in ISO rules.

329. No interested parties have opposed the AESO’s TOAD initiative, and the DUC specifically acknowledged its support of the reorganization of the AESO’s T&Cs.

Commission Findings

330. The AESO stated that it is in the early stages of its TOAD initiative. The Commission has not been provided with a definitive set of subsequent modifications to the tariff by the AESO. Furthermore, the AESO has described in its Application an ongoing rollout and modification of this initiative after the Commission disposes of the AESO 2010 GTA.

331. From the evidence submitted by the AESO, the Commission understands that a repository of definitions will reside with the AESO and will be modified by the AESO. Given the potential for the tariff to materially change with revised definitions, the AESO has proposed that it apply to the Commission for approval of subsequent amendments or revisions affecting the T&Cs.136

332. Accordingly, the Commission directs the AESO to apply for approval of amendments which would materially change the tariff. Given this direction, Commission approves the AESO’s proposed reorganization of its T&Cs, subject to findings made in relation to specific provisions of the T&Cs below.

10.2 Connection Process Redesign

333. The AESO submitted that the AESO’s connection process redesign began in 2009 and that its proposed changes to the connection process affect certain provisions of the T&Cs respecting system access service requests and to a lesser extent the construction contribution for

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135 Application, paragraph 338.
136 AESO Argument, paragraph 380.
connection projects and on the financial obligations for connection projects. The AESO has proposed a new connection model that implements changes to the process to connect load and generation to the transmission system and to improve upon the interaction between the AESO, TFOs and market participants for responding to requests to system access service. The principle behind the proposed model is that market participants will become more engaged and more accountable for the progress and completion of their connection projects, including the detailed design work, which is currently being completed by the AESO.

334. The AESO also proposed that TFOs would make determinations with respect to specific facilities constructed to provide system access service. The AESO also proposed revisions to the provision of financial security and construction contributions for connection projects whereby financial security and construction contributions would be provided by a market participant to a TFO.137

335. The AESO submitted that the proposed connection model is expected to expedite the overall connection process and enable the AESO to transition to a role of governance and oversight in order to guide the process from service request to commercial operation.

336. The AESO submitted that no party has raised concerns in evidence with the changes proposed to accommodate the revised connection model in general, but it acknowledged that concerns were expressed about specific aspects of the new connection model.

337. The UCA did not object to the connection process redesign proposed by the AESO, but asked that the Commission confirm in the Decision that the AESO will continue to provide Rate DTS customers with the option of having the AESO prepare connection proposals, and that the costs incurred will form part of the AESO’s administrative costs. The UCA indicated that the AESO confirmed this was the case in response to UCA.AESO-001.138

338. Access Pipeline Inc. (ACCESS) supported the AESO’s proposed changes to the T&Cs that will support the AESO’s connection process redesign and, in turn, improve connection timelines and project completions.

339. The DUC supported the proposed changes to the T&Cs that support the connection process redesign. The DUC submitted that while it is supportive of the new model and expected it to result in a more effective connection process.

340. ATCO Electric submitted that the AESO proposal to allow market participants to work with TFOs and other third party consultants to prepare connection proposals will introduce uncertainty into the connection proposal process and increased risk that connection proposals will not be prepared in a consistent and nondiscriminatory manner. ATCO Electric expressed concerns that absent AESO leadership and oversight of the connection process, industry churn or development of inappropriate plans could result.

Commission Findings

341. Given the AESO’s commitment in UCA.AESO-001, the Commission expects that Rate DTS customers will continue to have the option of having the AESO prepare connection proposals with the related costs forming part of the AESO’s administrative costs.

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137 Application, page 104.
138 Exhibit 79.01.
342. The Commission approves, in general, the overall approach being taken by the AESO with its Connection Process Redesign project, but it will address the specific aspects where parties expressed concerns, within the following sections:

- Standard facilities vs. Good Electric Industry Practice.
- Definition of Good Electric Industry Practice.
- Delegation to Transmission Facility Owners.
- Financial Obligations for Connection Projects.
- Disputes with respect to Good Electric Industry Practice.

### 10.2.1 Standard Facilities vs. Good Electric Industry Practice

343. The AESO indicated that the standard facilities definition has been in place since 2006 but it was prompted to review the standard facilities practice as a result of difficulties arising from the application of the definition. The definition specifies that standard facilities are “the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards.”\(^{139}\) The AESO also indicated that the AESO, market participants, and TFOs frequently did not agree on what constituted good transmission practice or on what criteria and standards should apply.\(^{140}\)

344. The AESO explained that since the beginning of 2006, its tariff has limited investment to no more than the cost of standard facilities which were to “generally consist of a single radial transmission circuit and a single transformer to supply an individual” point of delivery or point of supply. The definition of standard facilities was intended to provide clarity and transparency to a long-standing practice and to prevent higher than required standards for connection facilities being pursued simply because investment was available to cover their cost.\(^{141}\) However, the AESO also submitted that the time and resources expended to develop the standard facilities therefore served no useful purpose, since investment was already limited by the maximum available based on the market participant’s contract capacity and investment term.\(^{142}\)

345. The AESO submitted that the primary intent of the standard facilities definition was to limit the investment in customer connections. However, given the better alignment between costs, investment levels and POD charges in the current tariff, there is less need to limit investment levels through the use of the standard facilities definition.

346. The AESO proposed to remove the concept of standard facilities from its tariff and replace it with a definition of GEIP. The AESO described GEIP as a standard of practice exercised by expert judgment rather than prescriptive documentation.

347. AltaLink supported the AESO’s proposal to remove the concept of standard facilities from its tariff. AltaLink submitted that there is a lack of clarity respecting the standard facilities definition and particularly, what criteria and standards should apply. AltaLink considered that the standard facilities definition is no longer required to prevent the unnecessary use of available investment.

\(^{139}\) Application, paragraph 475.  
\(^{140}\) Application, paragraph 475.  
\(^{141}\) Application, paragraph 473.  
\(^{142}\) Application, paragraph 482.
348. ACCESS supported the removal of standard facilities from the tariff and adoption of the standard of GEIP as the standard against which to assess the reasonableness of customer connection requests.

349. TransCanada supported moving away from the AESO’s current definition of standard facilities, which TransCanada views as too restrictive.

350. FortisAlberta stated that it was not opposed to the proposed move from the application of a standard facilities criterion to one of GEIP. FortisAlberta also noted that this move may impact the current frequency and levels of contributions which may also be the driving force behind the current request for the Rider I mechanism.

351. The CCA indicated that it is indifferent as to whether the AESO replaces the definition of standard facilities with GEIP. The CCA however submitted that industry practice must continue to ensure that there is economic discipline and that least cost interconnection facilities are constructed while meeting applicable standards of reliability, protection, operating criteria and standards. The CCA expressed concerns that change in the standard for investment from least cost to a range of reasonable practices may or may not provide sufficient economic discipline. The CCA considered while the standard facilities definition includes criteria such as “the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards” the GEIP definition is more open to interpretation.

352. The CCA expressed concerns that alignment between costs and investment levels may not act as a useful check once the underlying costs are no longer subject to the economic discipline resulting from the least cost standard. Additionally, the CCA submitted that the AESO should be directed to make, in consultation with stakeholders, a set of operating rules that would provide the needed flexibility and clarity for the existing standard facility definition without compromising the intent of the standard which requires investment by the AESO in least cost facilities. The CCA argued that “in the meantime, the existing standard facilities criterion should be continued without change.”

353. In Reply, the AESO submitted that the contract capacity, term, and maximum investment level provide adequate economic discipline on connection projects, and that a market participant’s response to the price signal provided will provide the useful check referred to by the CCA. The AESO also noted that standard facilities do not restrict what connection facilities are actually built, they simply define an upper limit for investment, which is a role that will be performed by the maximum investment formula under the AESO’s proposed tariff.

Commission Findings

354. The Commission notes the views expressed by the AESO and other parties that there are several shortcomings with the continued use of the standard facilities definition including:

- use of a standard facilities definition rarely provided an acceptable level of service in Alberta or that would be considered acceptable in a neighbouring jurisdiction;

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143 CCA Argument, paragraph 116.
144 CCA Argument, paragraph 120.
145 AESO Argument page 41, paragraph 223.
• inconsistency with actual practices;
• inefficient use of resources; and
• frequent disagreements have arisen resulting in project delays and tie-up of valuable resources.

355. The Commission acknowledges the comments of the AESO that very few individual connection projects would be impacted by removal of the standard facilities criterion as investment in customer interconnections is frequently limited by the maximum investment formula rather than the cost of standard facilities.  

356. The Commission approves the AESO’s proposal to remove the standard facilities definition from its tariff and replace it with the definition and application of GEIP as filed.

10.2.2 Definition of Good Electric Industry Practice

357. The AESO described GEIP as a standard of practice exercised by expert judgment rather than prescriptive documentation. GEIP was defined in the authoritative documents glossary and the AESO provided an update in its Argument (modified from the Application as underlined below):

“good electric industry practice” means the standard of practice attained by exercising that degree of knowledge, skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from a skilled and experienced person engaged in the same type of undertaking in the same or similar circumstances, and:

(i) includes determining what is reasonable in the circumstances having regard for safety, reliability and economic considerations; and

(ii) is not intended to be limited to the optimum practice, method or act, to the exclusion of all others, but rather is intended to include practices, methods and acts generally accepted in Alberta and neighbouring jurisdictions.

358. The AESO submitted that if parties object to modifying the definition in Argument, the revised definition could be dealt with in a separate process so as not to delay implementation of the tariff.

359. The CCA recommended that clause (ii) of the proposed GEIP definition, as proposed in the Application, be modified as follows to ensure that AESO investment is in least cost facilities:

(ii) is intended to include practices, methods and acts generally accepted in Alberta and neighbouring jurisdictions that meet the applicable criteria of reliability, protection, safety and operational requirements consistent with least cost service.

360. ACCESS submitted that employment of the “least cost” standard has been one of the most troublesome aspects in applying the Standard Facility definition. ACCESS supported the inclusion of economic considerations as included in the AESO modified definition of GEIP and

146 AESO Argument, page 41, paragraph 223.
147 CCA Reply.
submitted that this provides the AESO with the latitude to apply judgment in the review of connection proposals.

**Commission Findings**

361. The Commission notes the comments of the CCA respecting the need for economic discipline and its request for inclusion of least cost in the definition of GEIP.

362. The Commission expects that engineering knowledge and experience will be used to apply the GEIP criterion to determine the most economic alternative which will satisfy the applicable reliability and operating standards and requirements. The Commission considers that the AESO definition of GEIP will provide for a consideration of economic factors in the review of connection proposals. The Commission approves the modified GEIP definition as proposed by the AESO, but recognizes that there could be further modifications should the definition continue to evolve in the future.

**10.2.3 Delegation to Transmission Facility Owners**

363. The AESO proposed that the TFOs will be responsible to ensure that specific facilities constructed for system access service comply with GEIP and the TFOs may also deem facilities to be in excess of those required by GEIP. The AESO characterized the provision to deem facilities to be in excess of those required by good electric industry practice as a safety net. The AESO submitted that it expects that facilities would rarely be deemed to be in excess of those required by good electric industry practice.

364. The AESO indicated in its response to AUC.AESO-019 that it considers it appropriate for the TFOs to make determinations with respect to specific facilities constructed for system access service as the TFO is more familiar with the construction, ownership, and operation of transmission facilities. The AESO also indicated that “transmission facility owners are more conversant with what transmission facilities are actually representative of good industry practice and it seems reasonable that they would be able to identify facilities in excess of that standard.” The AESO also submitted that GEIP is a commonly referenced standard of practice that is familiar to TFOs, in part because of its similarity to GEIP defined in the transmission T&Cs under which the TFOs provide service to the AESO.

365. The AESO also proposed revisions to the provision of financial security and construction contributions for connection projects. Under this proposal, financial security and construction contributions would be provided by a market participant to a TFO under a schedule that correlates with the TFOs expenditures associated with a connection project.

366. ATCO Electric opposed the AESO’s proposal to delegate to TFOs and submitted that delegation will introduce uncertainty into the connection proposal process and create increased risk that connection proposals will not be prepared in a consistent and non-discriminatory manner. ATCO Electric also opposed the AESO’s proposal to delegate the collection and administration of financial security to TFOs. Financial security and construction contributions are discussed in section 10.2.4 of this Decision.

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148 Transcript, Volume 4, page 441.
149 Transcript, Volume 4, page 367.
150 Exhibit 71, Response to AUC-AESO-019.
151 Transcript, Volume 1, page 55.
367. ATCO Electric submitted that while section 9(2) of the Electric Utilities Act provides the AESO with the broad authority to delegate any power or duty conferred or imposed on it to any other qualified person it considers appropriate, the AESO is restricted in what it can delegate to TFOs under section 13 of the Transmission Regulation.

368. ATCO Electric submitted that under the principle of statutory interpretation, *generalia specialibus non derogant*, the more specific provision (section 13 of the Transmission Regulation) must be read to the exclusion of the more general provision (section 9(2) of the Electric Utilities Act). ATCO Electric also submitted that under the Electric Utilities Act, the AESO is the sole provider of system access service and as such, has no authority for the delegation of its sole responsibilities. ATCO Electric also acknowledged in Argument that it was prepared to work with the AESO and other market participants to arrive at a mutually acceptable solution that is practical in the circumstances and still recognizes the AESO's legislative responsibilities.

369. ACCESS, FortisAlberta, TransCanada, and the UCA also opposed the AESO’s proposal to delegate the responsibility of assessing GEIP and determination of facilities that are in excess of GEIP to the TFOs. They considered that various TFOs may provide different assessments of GEIP and submitted that the AESO should undertake the assessment of what facilities meet and exceed its proposed GEIP standard to ensure consistency and reasonable application of the standard. They submitted that the AESO should be responsible for the application of GEIP in assessing transmission construction contributions.

370. ACCESS submitted that GEIP should be based upon the AltaLink Contribution Group recommendations and suggested that the AESO should be directed to finalize a reference document within six months of the Commission approval of the AESO’s 2010 tariff.

371. AltaLink supported the AESO’s proposal to delegate to the TFO the responsibility of assessing GEIP and the determination of whether facilities are in excess of GEIP. AltaLink submitted that section 9(2) of the Electric Utilities Act provides the AESO with a broad power of delegation. It also asserted that while the language of section 13 of the Transmission Regulation references certain responsibilities which the AESO may delegate, this is no way, restricts the scope of section 9(2) of the Electric Utilities Act. AltaLink submitted that given a TFO is qualified to apply the standard of GEIP, a TFO should be able to determine whether facilities are in excess of GEIP.

372. The AESO submitted that it is given broad authority under section 9(2) of the Electric Utilities Act to delegate certain duties to qualified persons. Further, this broad authority is not restricted by section 13 of the Transmission Regulation. The AESO further stated that the delegation of the determination of facilities within good electric industry practice does not mean that the AESO is abdicating its role as the sole provider of system access service. The AESO indicated that it retains overall responsibility for the connection process and the delegation of responsibilities within that process to a TFO does not detract from the AESO’s role.

373. The AESO claimed that good electric industry practice is a commonly referenced standard of practice that is familiar to TFOs. The AESO further asserted that there would be little inconsistency between TFOs and claims it would not be warranted for the AESO to insert

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152 Exhibit 71, Table 5-6.
into the connection process a procedure whereby the AESO must satisfy itself that every system access service request is being met through facilities that meet GEIP.

374. The AESO argued that it did not consider it practical to create and maintain a technical reference document defining standard connection configurations. The AESO also considered that the value of such a document has been reduced by the improved alignment between costs, investment level, and rates, and the more frequent limitation of investment by the maximum investment formula. The AESO also noted that facilities would rarely be deemed to be in excess of those required by GEIP, and therefore argued that it was not efficient or effective to create and maintain a reference document such as recommended by ACCESS.

Commission Findings

375. The Commission notes that several parties opposed the AESO proposal to delegate the responsibility of assessing GEIP and the determination of facilities that are in excess of GEIP to the TFOs due to concerns that connection proposals will not be prepared in a consistent and non-discriminatory manner, because various TFOs may provide different assessments of GEIP. The AESO acknowledged that discriminatory treatment of market participants could arise if the level of contribution required from a market participant differed from one TFO to another based on their different application of the GEIP criterion.\textsuperscript{153}

376. The Commission’s findings with respect to delegation to TFOs are subdivided in two parts:

- Legislative Framework.
- Use of Reference Documents.

Legislative Framework

377. In order to determine whether the AESO has the authority to delegate the determination of facilities in excess of GEIP to the TFOs, the Commission must consider the Electric Utilities Act, the Transmission Regulation and principles of statutory interpretation.

378. The Commission considers that in order for the principle of generalia specialibus non derogant to apply there must be a conflict between section 9(2) of the Electric Utilities Act and section 13 of the Transmission Regulation.

379. Section 9(2) of the Electric Utilities Act states:

\begin{itemize}
\item (2) Except when the power to delegate is restricted by this Act, by regulations made under section 41 or 142 or by ISO bylaws, the Independent System Operator may delegate any power or duty conferred or imposed on it under this or any other enactment
\item (a) to any of the members, officers or employees of the Independent System Operator, or
\item (b) to any other qualified person the Independent System Operator considers appropriate.
\end{itemize}

\textsuperscript{153} Transcript, Volume 1, pages 67-68.
380. Section 13 of the *Transmission Regulation* states:

13(1) Under section 9(2) of the Act, the ISO may, by agreement with a TFO or a DFO, delegate the preparation of any or all of

(a) the transmission system plan, or any aspect of it, or

(b) repealed AR 153/2010 s11,

(c) a needs identification document, or any aspect of it,

to one or more TFOs or DFOs, subject to any conditions that the ISO considers appropriate, but the ISO is responsible for reviewing and approving any plan or document prepared under the delegation.

381. In determining when two provisions are in conflict, Sullivan on the Construction of Statutes states:

When two provisions are applicable without conflict to the same facts, it is presumed that each is meant to operate fully according to its terms. So long as overlapping provision can apply, it is presumed that they are meant to apply. The only issue for the court is whether the presumption is rebutted by evidence that one of the provisions was intended to provide an exhaustive declaration of the applicable law.

[…]

When two or more provisions overlap, the courts try to give effect to each. They do not report to the conflict avoidance strategies at their disposal unless there is a genuine conflict that cannot be avoided through interpretation.154

382. The Supreme Court of Canada has established the test for when conflict exists between two provisions:

The test for determining whether an unavoidable conflict exists is well stated by Professor Côté in his treatise on statutory interpretation:

According to case law, two statutes are not repugnant simply because they deal with the same subject: application of one must implicitly or explicitly preclude the application of the other.

Thus, a law which provides for the expulsion of a train passenger who fails to pay the fare is not in conflict with another law that only provides for a fine because the application of one law did not exclude the application of the other…. Unavoidable conflicts, on the other hand, occur when two pieces of legislation are directly contradictory or where their concurrent application would lead to unreasonable or absurd results.155

383. The Commission considers that a plain reading of section 13 of the *Transmission Regulation* reveals no explicit or implicit restriction on the authority of the AESO to delegate,

155 Sullivan at page 330.
but is merely a specific example of certain written documents the preparation of which may be delegated to transmission facility owners or distribution system owners, with their consent.

384. Given that both provisions could apply according to their terms and since there is nothing to suggest that the more specific regulation was meant to be exhaustive, there is no reason to exclude the more general one. In other words, section 9(2) of the Electric Utilities Act and section 13 of the Transmission Regulation can be read on their own as the two are not directly contradictory and the concurrent application of both would not lead to unreasonable or absurd results.

385. However, given that numerous parties opposed the AESO’s proposed delegation, including a TFO that would be tasked with the duty, the Commission must consider whether the delegation should be approved for both practical and policy reasons.

386. Under principles of statutory interpretation, consideration can be given to the Electric Utilities Act as a whole in order to give effect to a plausible and coherent plan and to ensure that the purposes of the Act are met. Under sections 5 and 17 of the Electric Utilities Act, one of the ISO’s core duties is to provide open and non-discriminatory system access service. If the determination of facilities in excess of GEIP is delegated to TFOs, it is possible for the application of GEIP to be inconsistent and discriminatory which would be contrary to the ISO’s duty to provide open and non-discriminatory system access service.

387. Further, consideration should be given to the Transmission Regulation in order to gain a better understanding of the Electric Utilities Act. In Monsanto Canada Inc. v. Ontario (Superintendent of Financial Services), the Court found “While it is true that a statute sits higher in the hierarchy of statutory instruments, it is well recognized that regulations can assist in ascertaining the legislature’s intention with regard to a particular matter, especially when the statute and regulations are ‘closely meshed’.“[^156] The Commission notes that under section 13 of the Transmission Regulation the AESO may delegate the preparation of certain documents to the TFOs. The AESO requires the agreement of the TFO but the AESO is responsible for reviewing and approving any plan or document prepared under the delegation.

388. While ATCO Electric opposed the delegation, the Commission notes ATCO Electric’s acknowledgement that under section 39(2) of the Electric Utilities Act, a TFO is required to assist the AESO in carrying out its duties. Section 39(2) of the Electric Utilities Act states:

> **39(2)** Each owner of a transmission facility must, in a timely manner, assist the Independent System Operator in any manner to enable the Independent System Operator to carry out its duties, responsibilities, and functions. (emphasis added).

389. ATCO Electric submitted that a plain reading of section 39 of the Electric Utilities Act reveals that it is concerned with the maintenance and operation of the transmission system and not with matters related to system access service. However, the Commission is not persuaded by ATCO Electric’s narrow interpretation of section 39(2) of the Electric Utilities Act. The Commission finds that section 39(2) of the Electric Utilities Act is general enough to require TFOs to assist the AESO in carrying out any of its duties, responsibilities and functions. Given that one of the AESO’s duties is to provide system access service, the Commission finds that it is

reasonable for the AESO to engage the TFOs assistance regarding the determination of facilities in excess of GEIP.

390. Nonetheless, given the concerns of parties and the practical implications that could arise, the Commission directs that the determination of facilities in excess of GEIP take a similar approach as the framework provided in section 13 of the Transmission Regulation. Specifically, the Commission finds that the AESO can delegate the determination of facilities in excess of GEIP to TFOs; however, the AESO should review and approve any determination prepared under the delegation. Given the legislative framework and practical implications, the Commission considers that the AESO should retain final oversight over GEIP and the connection process including preparation of connection proposals by market participants, to ensure that there is non-discriminatory access to the system for all market participants.

391. The Commission directs the AESO to revise section 8, subsection 4 of the T&Cs to clarify that a market participant must pay any participant-related costs of facilities which are deemed, in the opinion of the ISO, to be in excess of those required by GEIP.

Use of Reference Documents

392. The Commission also notes the AESO’s comments respecting previous difficulties arising from the application of the standard facilities definition and that the AESO, TFOs and market participants frequently did not agree on what constituted good transmission practice or on what criteria and standards should apply. The Commission considers that the AESO, TFOs and market participants may experience similar difficulties regarding what constitutes GEIP in the absence of supporting reference documents.

393. The Commission considers that the efforts of the AESO to review and assess related subjects across the authoritative domains of ISO rules, the ISO tariff, and Alberta Reliability Standards to consolidate related subjects and eliminate duplication through its TOAD project will be helpful to market participants. As it relates to the interconnection process, the AESO lists eight guidelines respecting the Distribution Point of Delivery Interconnection Process including:

- Evaluation of Transmission versus Distribution Alternatives for Large Customers;
- New Point of Delivery Substations;
- Typical Supply Arrangements;
- Distribution Circuit Breaker Addition;
- Drivers of Need;
- Economic Evaluation;
- Upgrades to an Existing Substation; and
- Standards of Service.

157 The definition specifies that standard facilities are “the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards”.
158 AESO Application, paragraph 475.
159 Exhibit 71, Response to AUC.AESO-018 (b) and (c).
394. The AESO stated that connection guidelines are expected to be reviewed and integrated into information documents over the next two years as part of the TOAD initiative, but emphasized that the interconnection process documents are non-binding in nature.

395. The Commission considers that it would be helpful to market participants for the AESO to expedite its review of interconnection process guidelines to ensure that the new GEIP standard is applied consistently. The Commission considers that the AESO should make the development of connection process guidelines respecting the Distribution Point of Delivery Interconnection Process a priority in its TOAD project. The Commission expects that this review would be conducted in consultation with market participants.

10.2.4 Financial Obligations for Connection Projects

396. The AESO proposed revisions to the provision of financial security and construction contributions for connection projects, currently provided in Article 6 of the T&Cs. The changes proposed were summarized in the Application:  

In general, the AESO proposes that financial security and construction contribution be provided by a market participant to a TFO in a schedule that correlates with the TFO’s expenditures associated with a connection project. This is a material change from the AESO’s current practice which requires security for all participant-related costs prior to filing of a needs identification document or facilities application with the Commission, and payment of full contribution prior to the start of construction.

397. The AESO also explained that the provision relating to financial obligations for security and construction contributions have been revised to a staged approach whereby security and contributions are provided just prior to costs being incurred by the TFO.

398. ATCO Electric submitted that the AESO’s proposal is inconsistent with the provision of non-discriminatory access to the transmission system as delegating the collection and administration of financial security to TFOs increases the risk of the inconsistent treatment of market participants seeking system access service. ATCO Electric argued that this discretion should reside solely with the AESO.

399. ATCO Electric also questioned whether the AESO had given enough consideration to the additional administrative burden of its proposal or its alignment with TFO cost and commitment tracking mechanisms. ATCO Electric submitted that the AESO’s proposal to revise the provision of financial security and construction contributions for connection projects has not been sufficiently vetted with the TFOs to be adopted in its current form.

400. ATCO Electric requested that the Commission direct the AESO to engage TFOs fully in identifying a security management proposal that balances project risks and simplicity of administration with the desire to have financial security commitments more closely align with project costs and commitments.

401. In Reply, the AESO indicated that it had explored its staged security and contribution proposal in the working group formed to consider the amortized customer contribution option and other contribution provisions. The AESO stated that the working group met four times in

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160 Exhibit 70, Application, page 104.
161 ATCO Electric Argument, paragraph 22.
2009. While ATCO Electric did not participate in the working group, the AESO noted that the progress and conclusions of the working group were also discussed at three general stakeholder meetings. The AESO indicated that the working group did have a TFO representative (AltaLink). The AESO argued that it did sufficiently explore the practicality, alignment, and administration of its proposal.

**Commission Findings**

402. The Commission considers that the AESO’s proposal to have the financial security and construction contribution be provided by a market participant to a TFO in a schedule that correlates with the TFO’s expenditures associated with a connection project will achieve greater alignment between the TFO costs and the security requirements of connecting market participants.

403. However, the fact that one of the TFOs suggests that the AESO’s proposal has not been sufficiently vetted in its current form, raises a concern for the Commission. The Commission approves the revisions proposed, but expects the AESO and TFOs to work together to further identify and work to mitigate, or simplify, any potential administrative burden imposed on the TFOs.

404. Given the finding in section 10.2.3 that the AESO will maintain oversight of the connection process, the Commission finds that the AESO may delegate the collection and administration of financial security to the TFOs so long as the AESO maintains oversight to ensure that there is consistent and non-discriminatory treatment for all market participants.

**10.2.5 Disputes With Respect to Good Electric Industry Practice**

405. ACCESS argued that that ISO Rule 103.2 provides authority for the AESO’s dispute resolution role with respect to the determination of facilities in excess of good electric industry practice. ACCESS also submitted that “…disputes with respect to the application of the standard of Good Electric Industry Practice must be seen to fall within the scope of sections 25 and/or 26 of the Electric Utilities Act.”

406. In Reply, the AESO indicated that any disputes with respect to the application of GEIP would be a dispute concerning the application, interpretation or enforceability of the ISO tariff as set out in subsection 4(1) of section 1 of the proposed tariff. The AESO indicated that sections 25 and 26 of the Electric Utilities Act are concerned, respectively, with complaints about an ISO rule or about the conduct of the ISO and it is not correct to classify the resolution of any dispute regarding determination of GEIP as a complaint about either an ISO rule or its conduct.

407. AltaLink indicated that a dispute respecting GEIP could be resolved by recourse to existing dispute resolution procedures.

**Commission Findings**

408. The Commission’s direction in section 10.2.3 of this Decision provides that the AESO retain responsibility to ensure that the new GEIP standard is applied consistently and that connection proposals are prepared in a consistent and non-discriminatory manner.

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162 ACCESS Argument page 7
163 ACCESS Argument page 7
164 Exhibit 171, section 1, subsection 4(1).
409. Given this direction, it is expected that the nature and frequency of any disputes with market participants respecting the application of GEIP will be minimized.

410. The Commission considers that any dispute between a market participant and the AESO respecting GEIP can be resolved through the use of existing dispute resolution procedures. In this respect, the AESO may use section 103.2 of the ISO Rules to resolve disputes regarding interconnection proposals. Any disputes with respect to the application of GEIP would be a “dispute concerning the application, interpretation or enforceability of the ISO tariff”\(^{165}\) as set out in subsection 4(1) of section 1 of the proposed tariff.

10.3 Evaluation of Distribution vs. Transmission Connection Alternatives

411. The AESO proposed to remove Article 9.1(b) of the current tariff, which deals with the determination that is made for either a distribution or transmission solution. Under the proposed tariff, this determination by the AESO would now be addressed in section 4, subsection 2(3) of the proposed tariff.\(^{166}\)

412. Specifically, the AESO proposed to replace the language in Article 9.1(b):\(^{167}\)

if the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then the customer will pay the difference in cost between the most economic option and the transmission upgrade or extension in addition to any other customer contribution required under Articles 9.3 through 9.6.

413. The following language was proposed in section 4, subsection 2(3) of the tariff:

The ISO will review the requirements to provide system access service in response to the request of a market participant and determine the appropriate process for providing the system access service. (bolding in original)

414. The AESO argued that the more specific economic evaluation criterion in the current tariff can be removed because the proposed revisions to the investment formula serve to improve alignment among costs, investment level, and rates, and the more frequent limitation of investment by the maximum investment formula.\(^{168}\)

415. ACCESS argued that the specific economic evaluation criterion in the current tariff is needed due to the tradeoffs and complexities that exist when selecting between a transmission or distribution solution. It argued that transmission and distribution connection proposals should be developed in parallel and the customer should have “the ultimate right to choose its method of connecting to the system.”\(^{169}\) In Reply, ACCESS reaffirmed its position that industrial customers have unique needs best served by allowing these customers the ultimate choice in connection. Additionally, ACCESS submitted that there were other reasons to allow customers to determine the best connection option.\(^{170}\)

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\(^{165}\) Exhibit 171, section 1, subsection 4(1).

\(^{166}\) AESO Argument, page 45.

\(^{167}\) Exhibit 221.01, AESO Argument, Section 5.3.5, page 45.

\(^{168}\) AESO Argument, page 45.

\(^{169}\) ACCESS Argument, page 8.

\(^{170}\) ACCESS Reply, page 2.
First, the Commission has made significant efforts to harmonize the investment policies of the Distribution Facility Owners, the Transmission Facility Owners and the AESO. Second, as it must be assumed that any proposal put forward by the Distribution Facility Owner, the Transmission Facility Owner or the AESO will be consistent with the ‘optimization’ respectively of the distribution and transmission systems there can be no concern that the connection option chosen by the customer will be inconsistent with such optimization.

416. FortisAlberta disagreed with ACCESS suggesting that fomenting competitive proposals from distribution and transmission facility owners, respectively, to industrial customers, as suggested by ACCESS, would work to undermine optimal long term planning and is not in the public interest. Additionally, FortisAlberta argued that the selection practices have evolved over time and, while the practices may be improved, shortcutting or exempting larger customers from having to be part of overall system optimization in the longer term is not in the public interest.

**Relationship to Section 101 of the Electric Utilities Act**

417. Under section 101 of the Electric Utilities Act a customer requires both the approval of the AESO and the distribution facilities owner in order to connect to the transmission system.

418. The AESO noted that the distribution system owner’s role in the provision of electric distribution service is acknowledged under section 101 of the Electric Utilities Act, and stated that the proposed Rate DTS is in alignment with these statutory requirements. The AESO argued that parts (b), (c), (d) of the proposed Rate DTS are exceptions to the provision of service by distribution facility owners which the AESO argued is consistent with the Electric Utilities Act and the Hydro and Electric Energy Act. It also noted that the determination of GEIP, as proposed in the Application would have no impact on the legislative framework of section 101 of the Electric Utilities Act, or on the selection of a distribution or transmission solution.

419. FortisAlberta argued that the public policy underlying section 101 of the Electric Utilities Act emphasizes the “optimal long-term configuration for the benefit of all customers”, and that this should not be skewed to satisfy the wishes of larger customers. Furthermore, FortisAlberta pointed out that the provisions of the Electric Utilities Act emphasize the “need for and desirability of the distribution facility owner to remain integral to the system planning process” and therefore require the concurrence of distribution system owner and the AESO to determine if a direct connection to the transmission system is appropriate.

420. ACCESS argued that regardless of a release under section 101 of the Electric Utilities Act, market participants are “treated the same from an AESO investment standpoint as those that apply through a DFO.” As such, application of section 101 of the Electric Utilities Act does not affect the evaluation of a distribution or transmission solution.

**Commission Findings**

421. Section 101 of the Electric Utilities Act requires that an owner of the electric distribution system as well as the Independent System Operator approve an arrangement whereby the

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171 FortisAlberta Argument, paragraph 39.  
172 FortisAlberta Argument, paragraph 37.  
173 FortisAlberta Argument, paragraph 44.
customer would take service directly from the ISO. Given the language in section 101 of the 
Electric Utilities Act, the Commission finds that the choice in determining the connection type 
cannot ultimately reside with the customers.

422. The Commission recognizes that ACCESS’ proposal is not intended to circumvent the 
legislative requirements but rather is intended to give customers a greater role in the process 
involved in determining a transmission or distribution proposal. Specifically, ACCESS submitted 
that the service requirements are complex and unique for industrial customers and therefore 
customers should be allowed to determine the best connection option.

423. However, given the legislative framework the Commission is required to deny the request 
by ACCESS that would allow the customer to determine the best connection option from the 
available transmission and distribution options.

10.4 Customer Contribution Policy

424. The contribution policy and the associated maximum investment level, sets the maximum 
amount that the AESO is willing to invest towards the cost of extending service to new 
customers. The investment level is applied to the project connection costs assigned to the 
customer and the customer is required to pay any project connection costs in excess of the 
maximum investment.

425. The AESO proposed to generally maintain the contribution policy approach developed in 
previous proceedings, specifically the AESO 2005-2006 GTA and the AESO 2007 GTA. The 
AESO contribution policy provides for a multi-tiered maximum investment level which has been 
adjusted from existing levels based on analysis of recent project costs and the 2010 POD Cost 
Function and Investment Level Update Recommendations (POD Cost Function Update) included 
as Appendix F to the Application.

426. The AESO also proposed certain changes and reorganization of the contribution policy 
with the intent of increasing clarity regarding the classification of connection project costs and 
creating more consistent and predictable construction contribution results.

10.4.1 Contribution Policy Principles

427. The AESO indicated that the proposed changes to its contribution policy reflect the 
principles established during the proceedings for the AESO 2005-2006 GTA and the AESO 2007 
GTA and summarized the following principles as being applicable to the AESO’s contribution 
policy:

(a) Construction contributions should relate only to the local connection costs for system 
access service. Deeper system costs are properly the responsibility of all market 
participants receiving system access service and should be recovered from all market 
participants through rates for system access service.\(^{174}\)

(b) The underlying purpose of the contribution policy is to send price signals (reflective of 
the AESO’s economics) to market participants when they are considering siting 
alternatives for their facilities.\(^{175}\)

\(^{174}\) Decision 2005-096, page 43.

\(^{175}\) Decision 2005-096, page 43.
(c) An excessive local investment allowance could provide incentives for market participants to pursue higher standards of connection facilities than required and justify doing so on the basis that the cost of the higher standard facilities would not exceed the permitted investment allowance.\textsuperscript{176}

(d) Because an incremental revenue approach may place undue upward pressure on rates, maximum investment allowances should be below a level representing the incremental revenues expected to arise from the connection of a new system access service.\textsuperscript{177}

(e) Investment allowances should be set with regard to the anticipated costs of connecting a system access service reflecting acceptable standards of functionality and service established by the AESO.\textsuperscript{178}

(f) Connection facility service characteristics and standards of functionality may change over time.\textsuperscript{179}

(g) Cost, not revenue, is the appropriate starting point for establishing the contribution policy.\textsuperscript{180}

(h) Significant economies of scale occur as the size of connection projects increases, and such economies of scale should be reflected in the functional form of the maximum investment curve.\textsuperscript{181}

(i) It is still necessary to maintain the dual-use formula (implemented through the substation fraction) to ensure that market participants that are primarily generators are not able to gain an effective exemption from the requirement in the \textit{Transmission Regulation} that generators are to pay for their local connection costs.\textsuperscript{182}

(j) The POD cost function used as the basis for the Rate DTS POD charge should be used as the basis for the maximum investment function.\textsuperscript{183}

(k) Electric distribution system owners and direct-connected market participants should be treated comparably under the contribution policy in the AESO’s tariff.\textsuperscript{184}

428. The AESO indicated that it had reviewed suggestions from the stakeholder consultation respecting contribution policy principles that was led by AltaLink.\textsuperscript{185} The AESO submitted that it had addressed the majority of the suggestions but it also provided additional comments regarding certain recommendations:

(l) The contribution policy needs to consider minimizing intergenerational inequity; and

\textsuperscript{176} Decision 2005-096, page 44.
\textsuperscript{177} Decision 2005-096, page 44.
\textsuperscript{178} Decision 2005-096, page 44.
\textsuperscript{179} Decision 2005-096, page 44.
\textsuperscript{180} Decision 2005-096, page 44.
\textsuperscript{181} Decision 2005-096, page 56.
\textsuperscript{182} Decision 2005-096, page 57.
\textsuperscript{183} Decision 2005-096, page 61.
\textsuperscript{184} Decision 2007-106, page 92.
\textsuperscript{185} Decision 2007-106, page 103.
\textsuperscript{186} Application, paragraphs 453-458.
(m) The contribution policy needs to consider that most market participants should not pay a contribution for standard facilities, such that utilities are compensated for the assets they own, operate, and use to provide service.

With respect to principle (l), the AESO indicated that this principle is similar to the rate design principle of stability and predictability which can be achieved if rates are designed to reflect the primary cost causation principles. The AESO generally considered that this conclusion would also apply to the contribution policy and that a contribution policy based on sound cost causation principles should address any concerns about intergenerational equity. The AESO also indicated that recognition of cost inflation was mentioned as an element of this recommended principle. The AESO indicated that it was appropriate to revise or update investment levels through an approved methodology generally at the same time rates are revised or updated, and proposed such an update methodology in its Application. This proposal is discussed in section 11.1 of this Decision.

429. With respect to principle (m), the AESO submitted that changes to investment levels should be based on actual project costs and should not rely on ensuring that a specific proportion of market participants do not pay a contribution. The AESO indicated that it was reasonable to base investment levels on actual project costs and this approach was applied in the 2010 POD Cost Function and Investment Level Update Recommendations (Appendix F).

430. The AESO indicated that the second part of this recommendation relates to the reduction of the compensation to utilities when they receive construction contributions for assets they own, operate, and use. This precipitated the management fee proposals by AltaLink and ATCO Electric. The AESO submitted that its proposal for amortized construction contribution Rider I (section 9.3.1) would allow a utility to be compensated for the assets they own, operate, and use, but would not affect the number of market participants making contributions.

431. The DUC substantially agreed with the proposed contribution policy principles but suggested that certain contribution policy principles should be given more or less weight to reflect short-term conditions such as recent years of relatively high cost inflation.\(^\text{186}\)

432. The AESO explained that it was not always possible to simultaneously satisfy all contribution policy principles but argued that ongoing refinements to its contribution policy will generally satisfy a majority of principles and will avoid instability that may result from attempts to react to short-term conditions.\(^\text{187}\)

**Commission Findings**

433. The Commission notes that the DUC substantially agreed with the proposed contribution policy principles but suggested that certain contribution policy principles should be given more or less weight to reflect short-term conditions such as recent relatively high cost inflation. The Commission finds that the AESO has considered the matter of cost inflation in its proposal to update investment levels based on a composite price index and no further consideration is necessary at this time.

\(^{186}\) DUC Argument, pages 23-24.

\(^{187}\) AESO Reply, page 35.
434. The Commission has reviewed the contribution policy principles proposed by the AESO and considers that they reflect cost causation and are consistent with the principles established in previous proceedings.\(^{188}\)

435. The Commission considers that the overall intent of the contribution policy and maximum investment levels is to achieve a reasonable balance of what an individual customer pays upfront through a customer contribution relative to what all customers in a particular rate class pay through ongoing rates.

436. The Commission considers that the pending contribution policy module discussed in section 9.3.1 of this Decision will provide a useful forum for consideration of a number of related issues, including but not limited to: the levels of contributions and their effects on market participants, and contributions by distribution utilities with points of delivery serving multiple end-use distribution customers.\(^{189}\)

10.4.2 Maximum Investment Level

437. In its Application, the AESO proposed to generally continue the contribution policy approach established in the AESO 2007 GTA including consideration of the previously listed contribution policy principles. Article 8.0 of the AESO’s proposed T&Cs describes the process and considerations for determination of the customer contribution for a load interconnection project and the maximum investment levels.

438. The AESO contribution policy provides for a multi-tiered maximum investment level which has been adjusted from existing levels based on analysis of recent project costs and the POD Cost Function Update. The AESO indicated that the POD Cost Function Update also provided certain updates to a number of aspects of the original study completed for the AESO 2007 GTA, as described below.\(^{190}\)

(a) A composite inflation index was developed from Statistics Canada cost indices to replace the Alberta consumer price index used in the original study.

(b) Recent connection project costs were examined to determine substation and line costs for the development of the composite price indices and determination of the primary service credit.

(c) Connection project costs were collected and initially analyzed based on standard facilities costs and a multiplier of 1.15 was then applied to define the maximum investment function, which would result in total investment of $440.2 million for the 64 projects included in the analysis.

(d) The analysis was then repeated using the total costs for facilities actually built for each connection project and a multiplier of 1.06 to calculate a maximum investment function, which would yield nearly the same total investment of $439.3 million for the same 64 projects.

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\(^{189}\) During the oral portion of the proceeding, the AESO stated that it has not re-evaluated whether contribution waivers should apply for distribution utilities at Transcript, Volume 4, page 392, lines 2-25 and page 393, lines 1-25, since the 2006 GTA.

\(^{190}\) AESO Application, Appendix F, 2010 POD Cost Function and Investment Level Update Recommendations, pages 13-14.
439. The AESO also proposed to escalate the maximum local investment using the new composite inflation indices both for the investment levels included in a tariff application and annually between full tariff applications.

440. FortisAlberta did not object to the AESO’s proposed maximum investment levels but indicated that investment levels could be included in the pending management fee generic proceeding since investment levels under the AESO tariff have been the driving force for Rider I proposals.\footnote{FortisAlberta Argument, page 8.}

441. The DUC submitted that the maximum investment levels are too low and customer contributions will be higher than historical levels.

**Commission Findings**

442. The AESO’s proposed investment levels represent an overall increase in investment levels and a resulting decrease in construction contributions as evidenced by sample calculations conducted by the AESO.\footnote{AESO Response to AUC.AESO-024.} Further, the current contribution policy and maximum investment levels have not dissuaded AESO customers from requesting a greater number of new interconnections than can be immediately accommodated by the AESO and the TFOs.\footnote{AESO indicated (Transcript, Volume 4, page 448) they continue to experience a backlog of connection requests.}

443. The Commission finds that the AESO has considered all relevant contribution policy principles and has conducted a comprehensive review of the 2010 POD Cost Function including evaluation of cost categories in the determination of maximum investment levels. The Commission is not persuaded that further adjustments to the maximum investment levels are necessary at this time as suggested by the DUC; however, maximum investment levels may be considered in the contribution policy module.

**10.4.2.1 Modified Multiplier**

444. The AESO submitted that an adjustment was required to the multiplier used in the determination of maximum investment levels to accommodate the removal of the standard facilities definition and prevent an unintended increase in investment levels.

445. The AESO developed maximum investment levels using a multiplier of 1.06 such that the distribution of investment coverage for connection projects was similar to that approved in the AESO 2007 GTA.\footnote{Exhibit 10, pages 14-16.} The AESO determined that reducing the multiplier from 1.15 to 1.06 resulted in a total investment for all 64 projects in the data set of $439 million, compared to a total investment of $440 million based on the current standard facilities cost.\footnote{Application, paragraphs 500 and 501.}

446. The AESO submitted that maintaining similar coverage demonstrates that the investment levels are reasonable and appropriate, and the multiplier should not be adjusted upward to provide an arbitrary increase in investment levels.
447. The DUC recommended\(^{196}\) that the multiplier of 1.15 not be reduced to 1.06 and submitted that the maximum investment levels should be moved gradually upwards to produce customer contributions that are closer to historical levels.

**Commission Findings**

448. The Commission considers that calculation of the maximum investment levels using a multiplier of 1.06 provides for a distribution of investment coverage for connection projects that is similar to that approved in the AESO 2007 GTA. The Commission finds that maintaining similar coverage to historical levels is reasonable and it is not persuaded that further increases to the investment level are required at this time as suggested by the DUC. The Commission approves the AESO’s proposal to reduce the multiplier from 1.15 to 1.06 as filed, however the multiplier may be considered in the contribution policy module.

**10.4.3 Prepaid Operations and Maintenance (Prepaid O&M) Charge**

449. The AESO proposed to revise subsection 8(9) of its T&Cs related to its operations and maintenance charge. The AESO proposed the following changes to its current tariff:

- In line with the Transmission O&M Cost Study that was included with the application, the present value charge that reflects the operations and maintenance associated with incremental capital costs will be increased from 12% to 14.5%.
- In line with the AESO’s proposal to remove the concept of standard facilities from its tariff in favour of the concept of good electric industry practice, the AESO proposed that the operations and maintenance charge apply to all costs in excess of the maximum investment level applicable to the project as well as to the costs of any facilities deemed to be in excess of those required by good electric industry practice.\(^{197}\)

450. The AESO explained that, in general, the purpose of its Prepaid O&M charge is to provide economic signals to connecting customers by having the customer pay for the incremental cost of operations and maintenance, including associated overheads on connection costs considered to be optional facilities. This would ensure that other customers are not required to subsidize a new customer who requires the optional facilities.

451. The Prepaid O&M charge was first introduced in the tariff in the AESO 2005-2006 GTA. While the Board approved the inclusion of a Prepaid O&M charge in Decision 2005-096, the Board also provided the following direction to the AESO:

**20A Conduct Further Analysis on Appropriate Prepaid O&M Rate**

While the Board believes that the adoption of a 12% prepaid O&M surcharge is directionally appropriate and should be applied for the purposes of the 2006 tariff, the Board is not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs. Accordingly, the Board directs the AESO to conduct further analysis of the appropriate amount of the prepaid O&M surcharge and to reflect their findings in the design of the surcharge included no later than with the AESO’s 2008 General Tariff Application.\(^{198}\)

\(^{196}\) DUC Argument, page 24.

\(^{197}\) Exhibit 221.01, AESO Argument, paragraph 285, page 51.

\(^{198}\) Decision 2005-096, page 69.
452. In Decision 2007-106, with respect to the AESO 2007 GTA, the Board directed the AESO to:

18 Conduct a Study of Incremental TFO O&M
Direction 20A instructed the AESO to conduct a study of incremental TFO O&M to be included in the AESO’s 2008 GTA. However, as the AESO did not advance the completion of this direction in the Application, as it did with other aspects of the customer contribution policy (such as the AESO’s advancement of the cost study used in support of the AESO’s revised maximum investment function), the Board does not have any basis at this time to revise its finding in Decision 2005-096 that, on average, $0.12 of incremental TFO O&M costs will be generated by each $1.00 of capital investment in an interconnection facility. However, additional research into the relationship between incremental TFO O&M costs and POD capital costs remains valuable. Accordingly, the Board directs the AESO to respond to Direction 20A from Decision 2005-096 in its next GTA.\footnote{Decision 2007-106, page 106.}

453. In Decision 2007-106, the AESO was directed to apply the operations and maintenance charge to both standard facilities required to provide service to the customer where these costs are eligible for local investment as well as to facilities which exceed the standard facilities required to provide service to the customer.\footnote{Decision 2007-106, page 106.} This direction was later the subject of a Review and Variance (R&V) Application. With respect to the R&V Application, on July 13, 2009, the Commission issued Decision 2009-105,\footnote{Decision 2009-105: Alberta Direct Connect Consumers Association et al, Review and Variance of Decision 2007-106: Second Stage (Application No. 1566390, Proceeding ID. 108) (Released: July 13, 2009).} Review and Variance of Alberta Energy and Utilities Board Decision 2007-106: Second Stage. In Decision 2009-105, the Commission determined that the operations and maintenance charge should not be added to the cost of standard facilities, but should continue to be applied to optional facility costs.\footnote{Decision 2009-105, paragraph 40, page 10.}

454. The AESO’s position in the R&V proceeding was that Rate DTS recovers the operations and maintenance costs arising from a connection that are associated with standard facilities and operations and maintenance costs arising from connection costs that are in excess of standard facilities should be recovered through an operations and maintenance charge and paid as a construction contribution.

455. In Decision 2009-105, the Commission also addressed the distinction between standard facilities and the maximum investment level and determined that:

[T]he O&M Charge should not be applied to Standard Facilities, whether the cost of those facilities falls below or above the level of the AESO’s maximum investment allowance.\footnote{Decision 2009-105, paragraph 52, page 10.}

456. The Commission also found:

53. Notwithstanding the acceptance by the Board, in both Decisions 2005-96 and 2007-106, that, in the absence of better information, there is a linear relationship between O&M costs and interconnection capital costs, the Commission considers that the nature of that relationship has yet to be fully determined. In this regard, the Commission notes
that the Board directed the AESO to undertake a more in-depth study of the relationship between incremental O&M and interconnection capital costs in Decision 2005-096.

54. In light of this uncertainty, with regard to Standard Facility amounts above the maximum investment level, the Commission is not prepared to accept the arguments of IPCAA regarding the proportionality of O&M costs to capital costs. Further, given the AESO’s statement that its contribution policy does not preferentially apply investment to either the substation or line portion of an interconnection, the Commission is not prepared to apply the O&M Charge to Standard Facilities in excess of the maximum level based on PICA’s assumption that the length of line may, in some cases, dictate the amount of the capital investment and associated O&M.

55. However, the Commission awaits the AESO’s analysis of the relationship between incremental O&M and interconnection capital costs as was originally directed by the Board in Decision 2005-096, and will revisit this matter once that analysis has been completed. The Commission directs the AESO to provide its analysis no later than at the time of its next GTA.204

457. Under its current proposal, the AESO has indicated that Rate DTS will recover costs related to investment in new services, including recovery of operations and maintenance, up to the maximum investment level. Whereas connection costs and related operations and maintenance costs above the maximum investment level should be recovered through the Prepaid O&M charge and paid as a construction contribution.

458. This is a different position from what it had stated in the R&V proceeding with the key difference being the treatment under the tariff of connection costs that are in excess of Standard Facilities (current tariff) versus connection costs that are in excess of the maximum investment level (proposed tariff). In proposing this change, the AESO concluded that, on balance, the frustrations and concerns associated with the Standard Facilities definition now outweigh any remaining concerns with applying the operations and maintenance charge to all costs in excess of the maximum investment level applicable to the project.205

459. In an ATCO Electric information request, the AESO was asked to explain how the AESO’s proposal does not conflict with arguments advanced in the R&V Application regarding the fact that:

- operations and maintenance costs are recovered in the annual revenue requirement of each TFO and as a result are recovered through the DTS rate;
- customers will be subject to the operations and maintenance costs twice (through rates and the prepaid operations and maintenance); and,
- the prepaid operations and maintenance charge results in cross subsidies between new customers with optional facilities and other customers.206

460. In its response the AESO stated:

The listed points of argument from the review and variance application are in large part mitigated by excluding the O&M charge from facilities covered by investment. For

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204 Decision 2009-105, paragraphs 53-55, pages 10-11.
205 Application, paragraph 518, page 122.
206 Exhibit 77.01, IR Response AE.AESO-006(b)
example, there are 32 projects in the POD cost function data set from 2006 to 2009, years in which the standard facilities definition was in place in the AESO’s tariff. Those 32 projects cost a total of $323 million (in 2010 dollars). Using the 2010 investment function based on standard facilities as provided in the POD Cost Function Workbook (Appendix G to the application), that total cost would have the following breakdown:

- 69% (or $222 million) would be covered by investment in standard facilities;
- 22% (or $73 million) would be standard facilities above the maximum investment level; and
- 9% (or $28 million) would be facilities in excess of standard and not eligible for investment.

The AESO’s proposed O&M charge would not affect the standard facilities covered by investment, since those facilities would continue to be excluded from the O&M charge. The AESO’s proposed O&M charge would also not affect the facilities in excess of standard, since those facilities were previously subject to the O&M charge and would continue to be so. The AESO’s proposed O&M charge would affect only the 18% of costs associated with standard facilities above the maximum investment level. The AESO considers that reducing those costs impacted by the application of an O&M charge to only 18% of all project costs reduces the concerns expressed by the AESO in argument in the review and variance proceeding.

461. A number of parties commented that the AESO’s proposal in this GTA was inconsistent with the Commission’s determination in Decision 2009-105. Both ATCO Electric and the DUC argued that the revised approach should be rejected as the Prepaid O&M charge represents a double counting, with recovery of the same cost through the DTS rate.

462. IPCAA and the DUC both questioned the legitimacy of recovering the Prepaid O&M charge as a construction contribution. IPCAA commented that operations and maintenance is intrinsically an annual cost yet, under the tariff, the cost is being transformed into a lump-sum prepaid operations and maintenance amount and recovered as a construction contribution. IPCAA submitted that an annual flow through of operations and maintenance expenses would better reflect cost causation.

463. IPCAA noted that historically, billing limitations have forced utilities to depart from the annual recovery of annual charges; however, modern billing systems can implement the customer specific charges required for the flow through of annual operations and maintenance expenses.

464. IPCAA pointed out that the approach of calculating a lump-sum amount for operations and maintenance requires speculative estimates of discount factors and inflation rates stretching 20 years into the future. The inevitable variance between these long-term estimates and the actual annual operations and maintenance expense creates an unavoidable risk impacting other market participants as well as the party making the contribution. If the long-term estimate is too low, all other market participants will in effect be locked into a long-term subsidy payment; if the estimate is too high, the contributing party will be locked into a long-term subsidy payment.207

207 Exhibit 189.01, IPCAA Evidence, pages 9-10.
465. IPCAA recommended that the Prepaid O&M charge associated with all new construction contributions should be recovered on an annual basis, and that the practice of calculating a lump-sum prepaid operations and maintenance amount be terminated.

466. The DUC submitted that taking a forecast of operations and maintenance costs and converting it to a capital amount that is then used to reduce the TFO’s rate base results in several inconsistencies. The DUC noted that the prepaid operations and maintenance capital payment does not reduce the annual TFO operations and maintenance costs that flow through to the AESO’s revenue requirement. As a result, there is misalignment between the amount of prepaid operations and maintenance recovered and the corresponding offset associated with a reduction to the TFO’s rate base from the contribution amount.

467. The DUC submitted that the application of the Prepaid O&M charge should be by exception; an approach more consistent with historical practice. The DUC also noted that the AESO’s proposed POD cost function incorporates factors such as economies of scale and suggested that the more relevant place to deal with overall costs and contributions is in setting the maximum investment level.

468. The UCA and the DUC both submitted evidence to suggest alternate calculations of the Prepaid operations and maintenance rate of 14.5 percent. The UCA recommended a Prepaid operations and maintenance charge rate of 16.9 percent to reflect a limited inclusion of annual structure payments and linear property taxes in the calculation. The DUC recommended that a discounted Prepaid operations and maintenance rate of nine percent be used for the 2010 tariff to take into account its concerns with the data and methodology, the replacement cost of new transmission assets being materially understated, and to maintain a level of consistency with the current tariff.

469. The CCA submitted that the 14.5 percent rate recommended by the AESO be accepted by the Commission for this proceeding, but added that the AESO should be directed to provide an updated operations and maintenance analysis at the time of the next GTA. Other parties including ATCO Electric, TransCanada and IPCAA supported the DUC’s proposed rate of nine percent.

470. AltaLink took no position regarding the AESO’s proposed operations and maintenance charge rate of 14.5 percent, but opposed the UCA’s recommended charge rate of 16.9 percent. AltaLink submitted that the UCA’s proposal is not sufficiently supported by analytical rigour, potentially results in greater costs to new customers than existing customers over the lifetime of the transmission asset resulting in intergenerational inequity, and it ignores the results of the Transmission O&M Cost Study.

471. The DUC submitted that while a Prepaid O&M charge is needed, it is essential to recognize that the charge is incremental in nature and the objective should be to determine an appropriate prepaid operations and maintenance charge rate for certain incremental facilities and the incremental costs they impose. For this reason, it should only apply in exceptional

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208 Exhibit 216.01, DUC Argument, page 30.
209 Exhibit 230.01, DUC Reply, page 21.
210 Exhibit 213.02, UCA Argument, paragraph 108, page 20.
211 Exhibit 216.01, DUC Argument, page 28.
212 Exhibit 210.02, AltaLink Argument, paragraph 54, page 19.
circumstances. The DUC recommended that a Prepaid O&M charge should only be applied where customers request optional facilities deemed to be in excess of GEIP. Parties including ATCO Electric, TransCanada and IPCAA supported the DUC’s recommendation.

472. The UCA and the CCA recommended that the AESO’s proposal to apply the Prepaid O&M charge to facilities in excess of the maximum investment level be accepted.

473. The DUC also expressed concern that the Prepaid O&M charge increases the inequity between industrial and other non-industrial customers. The AESO’s low investment levels create an inequity between large industrial customers who pay capital contributions in cash and smaller customers who pay for capital contributions over time through their distribution utility rates. The DUC submitted that adding the Prepaid O&M charge to all capital contributions simply makes this bad situation worse.\(^\text{213}\)

**Commission Findings**

474. The Commission has reviewed the Prepaid O&M charge section of the Transmission O&M Cost Study submitted with the Application. The study recommends (and the AESO has proposed) a method of determining the Prepaid O&M charge amount based on average costs (embedded) across the electric transmission system rather than using a method based on the incremental costs of specific transmission equipment.\(^\text{214}\)

475. When the Prepaid O&M charge was first approved in Decision 2005-096, the Board directed the AESO to conduct further analysis on the amount of the Prepaid O&M charge because it was “not convinced that sufficient evidence has been gathered to determine that 12% figure appropriately tracks costs.”\(^\text{215}\) The Board directed the AESO to reflect its findings in the design of the surcharge.

476. In Decision 2007-106, the Board stated that “additional research into the relationship between incremental TFO operations and maintenance costs and POD capital costs remains valuable.”\(^\text{216}\)

477. Most recently the Commission, in Decision 2009-105, found that the nature of the relationship between operations and maintenance costs and interconnection costs has yet to be fully determined and directed the AESO to “to file its analysis of the relationship between incremental O&M and interconnection capital costs as originally directed by the Board in Decision 2005-096.”\(^\text{217}\)

478. The Transmission O&M Cost Study did consider using an incremental approach and found that the Prepaid O&M charge would be in the 2.0 percent to 2.5 percent range if it was based on the incremental maintenance costs of typical transmission facilities. In the end, this incremental approach was rejected within the Transmission O&M Cost Study because the incremental maintenance costs do not cover operations costs, nor do they cover the overheads associated with operations and maintenance. As a result, an incremental approach could not be developed that would reflect the total incremental operations and maintenance cost of operating

\(^{213}\) Exhibit 216.01, DUC Argument, page 20.
\(^{215}\) Decision 2005-096, page 69.
\(^{217}\) Decision 2009-105, paragraph 55, page 11.
electric transmission facilities.\(^{218}\) Instead, the proposed method of determining Prepaid O&M charge was based on average costs.

479. The DUC and ATCO Electric submitted that the prepaid operations and maintenance capital payment does not reduce the annual TFO operations and maintenance costs that flow through to the AESO’s revenue requirement, therefore the AESO must rely on the offset to ensure that the costs are not recovered twice. Neither the Transmission O&M Cost Study, nor the AESO’s evidence, have addressed the extent of alignment between the lump-sum calculation of the Prepaid O&M charge and the amount that is recovered through an offset as a result of the construction contribution.

480. At the hearing, in the following exchange between the Chair and Mr. Martin, the Commission pursued whether there was a misalignment:\(^{219}\)

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18 Q. Is there going to be over recovery of the O&M charge?
19 A. MR. MARTIN: There will never be over
20 recovery because of our nature of simply recovering the TFO
21 revenue requirement; however the two customers, new customer
22 versus old customer, there will be a payment of slightly more
23 than under other circumstances by one and slightly less than
24 under circumstances by the other.
25 Nothing more to add.
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481. The Chair again pursued it in an exchange with Mr. Hildebrand representing the DUC:

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20 Q. I had a question on prepaid O&M and actually talked with
21 the AESO panel about it. I can't even remember what day it
22 is now, but it's volume 4 I think, and it's just a little
23 further on than what you're looking at today. It's on page
24 472. So I was really having trouble with this whole idea of
25 a double payment, that there would be some customers would
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\(^{218}\) Exhibit 7, Transmission O&M Cost Study, page 22.

\(^{219}\) Transcript, Volume 4, pages 471-472.
have to pay a prepaid O&M charge and then, lo and behold, we get a TFO tariff that gets passed to the AESO and all the O&M is there, and Mr. Martin finally gave me some comfort that there was an offset at the TFO tariff level that would take out the prepaid O&M charges so that those would not flow through. And I must say I haven't gone to find any TFO tariffs between the time he told me that, but is this something you're familiar with occurring in the TFO tariff so we do offsets so there isn't an issue of double payment?

A. I think it's treated as a capital cost just like any other contribution.

Q. So it isn't a one dollar-for-dollar O&M offset?

A. No, that's my understanding. I would be happy to check on that if it's helpful.

482. The Commission finds that while there is an offset, it is not one-for-one, and the potential exists for this misalignment to result in a partial double recovery of the operations and maintenance cost, once through Rate DTS and again through the Prepaid O&M charge.

483. The Commission recognizes that incremental operations and maintenance costs of new transmission facilities are highly variable and dependant on the equipment and the technology employed. The operations and maintenance costs associated with these facilities are also not fixed costs in the long-term.

484. Lastly, the Commission has considered the lack of agreement among parties on how the rate should be calculated as well as IPCAA’s position that calculating a lump-sum amount for operations and maintenance requires speculative estimates of discount factors and inflation rates stretching 20 years into the future and resulting in an inevitable variance between these long-term estimates and the actual annual operations and maintenance expense amounts.

485. While the Commission agrees with the original intent of incorporating a Prepaid O&M charge in the tariff, upon further review of the information and analysis provided, the Commission does not consider that the proposed method for calculating the Prepaid O&M charge is sufficiently robust to ensure that the right party is paying the right cost. Further, the Commission acknowledges IPCAA’s statement that if the long-term estimate is too low, all other market participants will in effect be locked into a long-term subsidy payment; if the estimate is too high, the contributing party will be locked into a long-term subsidy payment.

486. For these reasons, the Commission directs the AESO to eliminate the proposed Prepaid O&M charge in its T&Cs. The AESO is directed to add to its T&Cs a provision that will charge customers requesting optional facilities deemed to be in excess of GEIP the full incremental maintenance cost, incremental operations cost, and overheads associated with the operation and maintenance of those facilities. The charge should be customer specific and recovered as it is currently, as a construction contribution. It is anticipated that the customer making the request for optional facilities deemed to be in excess of GEIP will be required to estimate the incremental operations and maintenance costs and that the estimate must be agreed to by the

220 Exhibit 7, Transmission O&M Cost Study, page 22.
221 Exhibit 7, Transmission O&M Cost Study, page 23.
AESO. The testimony of the AESO and other parties suggests that this will only be required in exceptional cases.

487. The Commission acknowledges that this change to the Prepaid O&M charge will result in reduced contribution amounts paid by connecting customers and an increase in the amount of the TFO revenue requirement that is flowed through to the AESO and recovered through the DTS rate. Therefore, the contributions in this area may be considered in the contribution policy module.

10.4.4 Contribution Policy Effective Date of January 1, 2010

488. The AESO proposed that the investment levels and other construction contribution provisions included in sections 8 and 9 of the proposed tariff be approved to be effective retroactive to January 1, 2010.

489. The AESO explained that the proposed investment levels represent a material increase compared to currently-approved investment levels, primarily because the current levels were based on 2007 connection costs forecast prior to the high levels of inflation that occurred from 2006 through 2008. The AESO considers the proposed investment level increase to be large enough that some market participants may attempt to delay projects until the 2010 tariff is approved. The AESO submitted that retroactive implementation of the 2010 investment levels and contribution provisions would avoid the potential for such delays and thus avoid any inefficiency associated with the potential impact on schedules.222

490. The DUC supported the AESO’s proposal for retroactive application of the investment levels and other construction contribution provisions. It noted that there has been a disparity between rates and investment levels as a result of the capital cost escalation, which could be better brought in line through the Commission’s approval of the earlier effective date.223

491. TransCanada supported the AESO’s proposal for setting an earlier effective date and it referred to correspondence sent on November 26, 2009 by the AESO to stakeholders. The letter indicated that the AESO planned to recommend to the Commission that “currently-approved contribution policy be treated as interim and refundable effective January 1, 2010.”224 TransCanada argued that its planning decisions have relied on the commitment the AESO put forward in the aforementioned stakeholder correspondence. As a result, it may be prejudiced by regulatory lag if the retroactive implementation of the 2010 investment levels and customer contributions provisions of section 8 and 9 of the proposed tariff is not granted by the Commission.

Commission Findings

492. The Commission finds that section 123 of the Electric Utilities Act allows the Commission to take into account revenues received and costs and expenses incurred within the year the tariff application is made. As well, a contribution policy with an effective date of January 1, 2010, better aligns rates and investment levels. For these reasons, the Commission sets the effective date to January 1, 2010, for construction contribution provisions included in sections 8 and 9 of the tariff as proposed by the AESO.

222 Application, paragraph 30, page 8.
223 DUC Argument, pages 30-31.
224 TransCanada Argument, paragraph 41.
10.5 **DTS Ratchet and Notice Provisions**

493. ADC recommended that the Commission direct the AESO to change the T&Cs with the following amendments:

- The demand ratchet and contract capacity be waived or reduced for energy reduction or efficiency projects to the extent that they reduce energy consumption.
- The five-year notice period be waived for energy efficiency projects for DTS load that has local interconnection and POD facilities that have no unrecovered investment.
- That the AESO be required to provide a five-year projection of the DTS tariff.\(^{225}\)

494. Both the DUC and IPCAA also endorsed the proposal submitted by ADC.\(^{226}\)

495. The AESO did not agree with ADC’s proposal. The AESO submitted that the payment in lieu of five-year notice represented a share of fixed system costs incurred to accommodate the contract capacity of a market participant over the five-year planning horizon of the transmission system.\(^{227}\)

496. The AESO argued that the considerations for ratchet and notice period as discussed in Decision 2007-106 remain relevant and appropriate today:

> [T]he Board considers that the prospect of a customer being subject to an exit fee if it reduces its maximum DTS contract capacity or terminates its DTS contract emphasizes the importance of accurately forecasting the amount of contract capacity prior to making a capacity commitment. Thus, the amount of capacity contracted for by DTS customers at specific PODs is an important factor in system planning, the existence of exit fee provisions in the tariff generally has a positive effect on the accuracy of the AESO’s system planning efforts.\(^{228}\)

497. The AESO submitted that the ratchet and notice provisions are a fair and efficient means of recovering fixed costs.\(^{229}\) In testimony, the AESO indicated that the impact of commodity savings are far greater than the impact from ratchet or notice period provisions and stated that “the transmission tariff, on its own, appears to have a very limited effect on what would result from energy efficiency or conservation project.”\(^{230}\)

498. The CCA submitted that if a project results in demonstrable demand reduction, then there is merit to incenting such a demand reduction.\(^{231}\) While not specifically endorsing the proposal by ADC, the CCA recommended that the Commission consider some type of incentive for demand reduction.

\(^{225}\) Exhibit 99.01, ADC Evidence, page 7.

\(^{226}\) Exhibit 99.01, ADC Evidence, page 2.

\(^{227}\) Exhibit 212.01, AESO Argument, page 54.

\(^{228}\) Decision 2007-106, page 113.

\(^{229}\) Exhibit 227.01, AESO Reply Argument, page 38.

\(^{230}\) Transcript, Volume 3, page 272, lines 8-10.

\(^{231}\) Exhibit 212.01, CCA Argument, paragraph 146.
The UCA did not agree with ADC’s proposal. The UCA argued that there are no new circumstances which warrant a consideration of a change to the current DTS ratchet and notice provisions.\footnote{Exhibit 212.02, UCA Argument, page 22.}

**Commission Findings**

The Commission understands that the payment in lieu of five-year notice represents a share of fixed system costs incurred to accommodate the contract capacity of a market participant over a five-year planning horizon for the transmission system. This provision is intended to mitigate the risk of stranded costs. However, the Commission considers that it may be desirable to augment incentives for market participants to pursue energy reduction initiatives in circumstances where it is clear that there is no risk of stranded investment and where there may be other benefits such as capital deferral or reductions in TMR or isolated generation costs.

Consequently, the Commission wishes to better understand the impact that the ADC’s proposal may have on the AESO and on other market participants. Therefore the Commission directs the AESO to provide a report to the Commission on this proposal at the time of its Refiling which will indicate specifically:

(a) the number of market participants that would reasonably be expected to take advantage of the notice relief sought by the ADC;
(b) the revenue impact if all market participants identified in part (a) were to exercise this option and reduce their DTS demand; and
(c) an assessment of whether it is feasible to apply incentives in specific regions and at a specific time in order to realize benefits such as capital deferral, or reductions in TMR or isolated generation fuel costs.

Upon receipt of this information, the Commission will make a further determination on the ADC’s proposal.

**10.6 Other Terms and Conditions Provisions**

**10.6.1 Discounting of Maximum Investment on Staged SAS Contracts**

Article 9.7 of the current T&Cs described the treatment of AESO customers who choose to stage their system access service (SAS) contracts by contracting for a lower initial contract capacity level and subsequently increase the contracted capacity level for the balance of the customer’s SAS contract. In the current T&Cs, Article 9.7(a)(i) provides that when a customer enters into a staged SAS contract, the determination of the maximum local investment level available in respect of the staged later years of higher SAS contract capacity is determined on a discounted present value basis.

The AESO described its proposal to eliminate Article 9.7(a)(i) of the current T&Cs from its proposed T&Cs. The AESO’s explanation for this change is reproduced below:\footnote{Revised Application, paragraph 510.}

510. Article 9.7(a)(i) of the current terms and conditions states that for system access services with expected increases or decreases in contract capacity, investment “will be determined at the start of the project by taking the present value of the local investment in the incremental load for the remaining contract term.” The result of this provision is that