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TO: *Electric Utilities Act* (EUA) Advisory Committee Members

RE: Transmission Development Policy

Attached for your information is a copy of the approved *Alberta Transmission Development Policy* paper.

I would like to thank your for your contributions to this process as we received many helpful and constructive comments and input from stakeholders in the development of this policy. We look forward to working together to develop the required regulation to implement the policy.

We now plan to have a draft regulation available for stakeholder review early in the new year. We will also use a matrix process to capture stakeholder views on the draft regulation and communicate our response to your comments on the regulation.

Yours truly,

Original Signed By

Kellan Fluckiger
Business Unit Leader

Attachment

Transmission Development

The Right Path for Alberta

A Policy Paper

Alberta Energy

Electricity Business Unit

November 2003

1. Introduction

This policy paper contains foundation principles, recommendations and supporting rationale for a sustainable transmission development policy for Alberta.

Transmission is by nature a long-term investment. This policy must therefore be forward looking and sustainable. Transmission policy must ensure that Albertans continue to receive safe, reliable, and efficient electric service wherever they live and work in the province. A robust transmission system will provide the underlying foundation for continued economic growth throughout the province and development of Alberta's vast resource base.

2. Background

Transmission is the backbone of the electric industry. Transmission serves the public interest through delivery of reliable, economic electric power, as well as providing a platform for economic development and a competitive wholesale market.

Transmission development must also recognize that Alberta is part of, and connected to the rest of the North American electric grid. Inter-ties are an essential part of a competitive market both as a means to import power when needed, to export surplus energy, and to ensure that the competitive wholesale market functions effectively.

Transmission policy must contribute to a stable investment climate in order to maintain investor confidence and support continued capital investment in generation and transmission in Alberta. Alberta's transmission system is already congested because growth in electricity demand and investment in new generation facilities have not been matched by investment in new transmission facilities.

3. Principles

3.1. Transmission – Foundation Principles

<u>The fundamental goal of the transmission policy is to ensure that consumers are served with reliable, reasonably priced electricity, and to support continued economic growth in Alberta.</u>

In meeting this objective, transmission development must consider the needs of consumers, investors, and the province - transmission policy must meet the public interest test and consider the interests of all parties. The transmission system must be efficiently planned and must anticipate and keep pace with forecast growth in demand throughout the province. Recovery of transmission costs on a broadly averaged basis, using postage stamp pricing for consumers remains the appropriate approach to paying for this type of infrastructure.

Adequate transmission must be in place to support new generation. Transmission should not be a barrier to generation development - investors should be provided with certainty and confidence that transmission will be developed in a timely and adequate manner so that their product can be transported to market. To align the interests of producers and consumers, generators will be required to make a financial commitment and contribution towards transmission system upgrades, based on their size and location on the system. The principles for generator funding and financial commitment respecting transmission system upgrades are described in the Conclusions and in the Appendix.

Transmission will continue to be regulated as a natural monopoly by the Alberta Energy and Utilities Board (EUB) to ensure open, non-discriminatory access and to protect the public interest. The EUB will continue to review transmission development proposals and their cost. The EUB will convene an open and public process in order to provide an opportunity for all interested parties to comment on plans to upgrade the transmission system. The Independent System Operator (ISO) will administer a transmission tariff approved by the EUB to assure equal, open and non-discriminatory access to the transmission grid.

Adequate transmission is required to ensure that the electric system is reliable and efficient and to ensure that the competitive wholesale market functions effectively. Transmission development must recognize that Alberta is connected to a North American system. Inter-ties are an essential part of a competitive market both as a means to import power when needed and to export surplus energy.

The following principles summarize and further articulate the fundamental goal stated above.

1. **Transmission is a monopoly service. This regulatory model for provision of transmission service best serves the purposes of Alberta.**
2. **Transmission is essential to reliability. Dependable provision of electric service underpins a strong economy and supports the safety and well being of every Albertan.**
3. **Transmission policy under a vertically integrated monopoly regime, like those of history, is fundamentally different from transmission policy within a competitive market for electricity.**
4. **Pricing and payment for transmission is fundamentally a cost most appropriately borne by the loads that are served by the transmission system on an equal basis, regardless of location.**
5. **Generators will make financial commitment and contribution towards upgrades of the transmission system based on generator size and location on the system.**
6. **Inter-ties are essential to a well-functioning market structure. Alberta is integrated with the electric systems of our neighbours. Transmission policy and the regulatory environment must facilitate open access to larger markets, while ensuring that Alberta's needs are met.**
7. **The policy should support appropriate consideration of export projects including the benefits to Alberta consumers.**

4. Conclusions

As we have examined transmission policy with the preceding principles and benefits in mind, we have reached a set of conclusions, which will drive specific actions for transmission investment in the province. Each of the conclusions presented below are discussed more completely in the following paragraphs and the Appendix.

1. **Transmission will remain a regulated monopoly. Transmission assets should be planned by the ISO and approved by the EUB. The EUB will regulate rates of return and recovery of transmission costs. Transmission facility applications will be reviewed and approved by the EUB in an open and transparent process. The regulatory and approval process must be timely and efficient.**

Transmission Ownership

Transmission will continue to be regulated as a natural monopoly by the EUB to ensure open, non-discriminatory access and to protect the public interest.

Since transmission is characterized by large economies of scale, there are efficiencies in having an incumbent Transmission Facility Owner (TFO) provide operations and maintenance services to new facilities that are required in a geographic area they currently serve. This localized "critical mass" of service infrastructure allows the incumbent TFO to respond to apparatus failures and other events that may jeopardize service to customers. A "patchwork quilt" of ownership does not have the same level of coordination or economy of scale and so it would not operate as reliably and efficiently. Contiguous ownership of lines, substation facilities and the associated operating infrastructure therefore provides the greatest assurance of reliable and safe operation of the transmission system for customers (and employees) and is therefore in the public interest.

To accomplish this intent, all new transmission facilities, including radial interconnection facilities, will be direct-assigned to the incumbent TFO's. Projects involving connections or upgrades to existing transmission facilities or use of existing right-of-ways will also be direct assigned to the incumbent TFO to ensure safe and reliable service.

Capital maintenance upgrades (i.e. like for like) should be reviewed in the context of a TFO's general tariff application and should not require a specific need application in front of the EUB. The ISO should review such programs to ensure that; the capital maintenance program is necessary in light of projected system upgrade projects, and the program satisfies established operating standards.

The ISO will also be required to create rules and processes respecting ownership of new facilities where new facilities involve multiple TFO's. This aspect is discussed in greater detail in the attached Appendix. It is also expected that the TFO's will continue to competitively tender elements for major projects such as; materials, equipment and construction.

Generators (and customers) may continue to own and operate transmission facilities on their own property for their own use (as per the *Hydro Electric Energy Act*).

Efficient Regulatory Process

To ensure timely approval of new transmission, the EUB must ensure that the review and approval process meets the following timelines:

- EUB decision on "need application" must be provided within six (6) months of receipt of application, and
- EUB decision on siting and permit of licence to construct and operate must be provided within six (6) months of receipt of application.

2. Transmission service must be provided using a non-discriminatory and open-access regime, administered by the ISO.

A non-discriminatory, open-access regime for transmission service is a mandatory feature of the competitive market structure in Alberta. The ISO is responsible for ensuring open and non-discriminatory access to the transmission system and for filing a tariff for review and approval by the EUB. This is provided for in the *Electric Utilities Act*, section 29.

3. Transmission embedded costs will be collected from consumers based on their use of the transmission system. Generators will be required to pay for local interconnection costs and to make a financial commitment and payment for transmission system upgrades based on their size and location on the system. Economic signals and prices from the wholesale electricity market should not be adjusted or unduly distorted with transmission costs.

Embedded Costs

The 50/50 pricing regime currently used for embedded costs will be discontinued effective January 1, 2006. Three important objectives are met by removing this pricing regime; (a) price distortions are not introduced into the wholesale market from the regulated transmission business, (b) consumers receive transparent pricing for transmission service, and (c) the market and pricing rules of Alberta are further aligned with those of neighboring jurisdictions.

Generator Cost Responsibility

In general, generators will be responsible to pay for several elements of transmission including:

a. Local interconnection charges
b. Location-based loss charges, and
c. A financial commitment and payment towards transmission system upgrades

The balance of remaining transmission costs (i.e. wires, TMR, IBOC/LBCSO, operating reserves, etc.) will be allocated to load.

Generator System Contribution Payment

New generators will be required to assume some costs for transmission system upgrades, in addition to their interconnection costs. This will be called a system contribution payment or **SCP**. One of the primary intents of the SCP is to act as a long-term siting signal for new generators. Since existing generators can't relocate and have limited options to reduce their output (considering their sunk costs), the **SCP** will only apply to new generators.

To meet the intent of this policy the **SCP** must:

a. Be stable, predictable and known upfront
b. Be simple to derive (i.e. will not require a system study to determine)
c. Vary based on generator size
d. Provide a location-based signal related to generator proximity to load centres
e. Be cost reflective but not based on actual transmission elements or specific costs incurred to upgrade the transmission system to accommodate a generator
f. Be a fair and reasonable amount (i.e. $/MW of capacity) in order to require all new generators to make a financial contribution to system upgrades
g. Be unaffected by the actions of other generators and will not change when another generator connects to the system
h. Be paid up front or paid over time, subject to satisfactory security provisions
i. Not be a commodity charge

The **SCP** will apply when an agreement is signed with the ISO. A date certain for commencement of the **SCP** will be specified in the transmission regulation.

Subject to satisfactory operation, the **SCP** made by the generator will be refunded to the generator over 10 years and those payments will be rolled into the rates paid by all load customers. Generators who fail to operate above a minimum capacity factor, which may vary by technology, will not obtain a refund, thereby reasonably protecting load customers from stranded transmission costs.

This will provide generators with a fair, certain and predictable investment climate. The terms will be known up front and generators will be provided an appropriate incentive to operate. In general, generators will be indifferent as to how the ISO plans and configures the transmission system. This will effectively eliminate any "race to be last" (or free-rider) issues, which typically plague contribution policies and funding of system upgrades.

Generators who pay local interconnection costs such as radial tie lines may not prohibit interconnection or access to those facilities by other generators or loads. If subsequent projects or loads become interconnected with such facilities, then the line from the new point of interconnection to the system become a part of system facilities and will be reinforced as needed by the ISO and TFO in accordance with this policy and EUB processes. In addition, costs for that portion of the interconnection, which has now become system facilities, will be refunded in accordance with the **SCP** mechanism.

The ISO will be responsible to create and obtain EUB approval for a generator **SCP** and refund mechanism consistent with the principles above and as illustrated in the attached Appendix.

Losses

The primary purpose of allocating losses to generators is to act as an effective locational incentive. Therefore, the loss factor methodology should be a long-term signal and relatively stable, to allow it to be factored into investment decisions. In order of priority, the loss methodology should:

a. Provide a locational incentive for generators

b. Allow the ISO to pursue transmission projects that will reduce overall transmission losses in the long term to the benefit of all consumers, as consumers ultimately pay for losses through their energy price

c. Where possible, provide a signal for generation dispatch, so as to minimise transmission losses on real-time basis

Alberta Energy considers that the current loss methodology used by the ISO must be reviewed and made more consistent with average system losses as opposed to marginal locational losses. The intended treatment of losses is further described in the attached Appendix.

Implementation

Policy implementation must be managed in a manner that is fair and reasonable. A regulation under the EUA will be prepared to implement the approved transmission policy. The regulation will specify that the tariff changes associated with STS will be effective on January 1, 2006. This will provide adequate time for existing contracts to expire or to be renegotiated to be consistent with this policy.

A date certain in the future will provide adequate time for parties to; address issues with supply and load contracts, create appropriate wire tariffs and to inform customers as necessary. It is intended that the regulation will prevail over any existing agreements to the extent of any inconsistency, conflict or uncertainty between the regulation and existing agreements. Notwithstanding the effective date for the proposed changes to the STS tariff, the ISO and the EUB will be directed to immediately initiate other changes contained in the policy and accompanying regulation in an expedient manner.

Alberta Energy is committed to a competitive marketplace. In a competitive wholesale market, it is expected that if generators no longer pay use of system charges, the competitive pool bidding system should force generators to reduce their bids by the amount of STS. Alberta Energy agrees that it would not be practical for the MSA to monitor individual bidding behavior but it is expected that the MSA will develop statistical means to monitor and analyze longer-term trends and thus, assess the impact of the change to the STS tariff.

4. **Transmission planning must be proactive in nature and must therefore lead load growth and generation development. Both population and economic growth are expected to continue in the province and transmission assets should be developed in a manner, which is prudently in advance of projected needs. It is not reasonable to expect that market signals, congestion pricing schemes or similar methods will result in timely construction of transmission facilities or assure their sufficiency to meet system needs.**

Consistent with the *Electric Utilities Act*, the ISO must assess the current and future needs of market participants, plan the capability of the transmission system to meet those needs, and arrange for necessary enhancements and upgrades to the transmission system. To ensure that transmission is developed in an appropriate and timely manner, the timelines, milestones and commitments for generation and transmission projects must be aligned to assure completion of both generation and transmission at nearly the same time.

To accomplish this, the ISO must initiate transmission preconstruction activities as a first step. These preconstruction activities may include such items as planning studies, engineering, or right-of-way acquisition. The ISO may bring forward a "need application" to the EUB for approval to proceed with preconstruction activities for a particular project or area development. This approach is different than the current regulatory process for need assessment before the Board. The Board will therefore be required to take a more comprehensive and longer-term view of need, including approval of likely transmission corridors when there is still some uncertainty about the precise nature of the future load and generation configuration on the system. When the need is approved, money spent on pre-construction activities (planning, siting, right-of-way acquisition) would be deemed prudent and recoverable by transmission facility owners.

Actual construction must then be staged to mesh with generator start-up and commissioning, subject to receipt of an appropriate commitment from a generator and permit and license from the EUB. There are a number of significant milestone dates in a generation project schedule, including; approval of provincial and federal Environmental Impact Assessments, award of engineering/prime contractor contract, order of major equipment, delivery of major equipment, ground breaking/site mobilization and construction power to site. The ISO will be required to identify suitable generator project milestones, which will trigger transmission construction and assure a continuing match of timelines between generator and transmission projects.

This initiative, in conjunction with establishment of regulatory timelines will reduce regulatory uncertainty and timing of transmission projects and provide comparable timelines between transmission and generation projects. This will also ensure that appropriate commitments are received from generators prior to actual construction and appropriately manage the risk associated with major transmission expenditures.

5. **Bulk Transmission System plans and facilities will, at a minimum, adhere to Western Electric Systems Coordinating Council (WECC) and North American Electric Reliability Council (NERC) standards and criteria to assure overall system reliability. The ISO will establish and maintain planning and operating standards and criteria for the Alberta transmission system.**

   It is expected that the ISO will develop planning and operating standards and criteria for the Alberta transmission system in consultation with stakeholders. As a starting point, it is expected that the N-G-1 reliability criteria (i.e. critical generating unit plus transmission line) will apply in Alberta. The ISO may exercise discretion in meeting these criteria. The Department expects that the ISO will consult with stakeholders in establishing the planning and operating standards and criteria for the Alberta transmission system.

6. **Transmission must serve and facilitate a competitive wholesale market. Transmission internal to Alberta should be reinforced so that about 95 per cent of expected economic wholesale transactions can be realized without transmission congestion.**

   The open access transmission structure in Alberta consists of an implicit system of injection and withdrawal rights for generators and loads. There are no explicit transmission rights. Given this structure, the transmission system must be relatively congestion free or the underlying market model will not function effectively.

   The ISO must therefore proactively plan transmission development to achieve this result of "congestion-free" transmission. The ISO will be required to ensure that the transmission system internal to Alberta is appropriately reinforced so that under normal operating conditions (i.e. all transmission facilities in service) all in-merit generation can be dispatched and virtually all economic wholesale transactions may be realized without congestion.

   Given the lumpiness of transmission additions, the 95 % criterion is intended to be a guideline and not an absolute number. Congestion may occur during planned maintenance, forced outages of transmission facilities and/or some critical generation facilities. It is also essential that the transmission system be sufficiently robust to allow timely and appropriate maintenance of transmission facilities.

   Constrained down payments will not be paid to generators. The ISO will be required to develop, in consultation with stakeholders, a system for managing real time congestion that may occur during abnormal conditions. In general terms, real-time congestion will be resolved by merit order re-dispatch, followed, if necessary, by pro-rata curtailment of parties with equivalent offers or bids. The real-time congestion scheme should use a reverse merit order to dispatch down units in a congested area, with units not in merit order being paid as bid so that congestion costs are not reflected in the system marginal price. In our market model, it is critical in the relatively few cases where transmission constraints are not removed, real time congestion arrangements should not set or distort market prices. Where generators are paid out of merit to alleviate a transmission constraint, the costs of the out of merit payments will be a transmission payment and not a form of uplift in the wholesale energy price. These costs should be allocated in the same manner as other "wires" costs. This matter is discussed further in the attached Appendix.

7. **Transmission development should eliminate the need for most transmission must run (TMR) contracts and remove most congestion areas in the long-run. Temporary**

congestion may occur in abnormal line configurations or in isolated instances of long-term limited growth, or other extraordinary circumstances.

Contractual "must-run" arrangements with market generators and RAS arrangements are short-term solutions. These solutions are not as reliable as building transmission facilities for the long-term and should not be considered as a substitute for transmission or preclude the development of a robust transmission network.

The ISO should however, be provided with some flexibility to consider TMR contracts where they are technically viable and a superior economic alternative (e.g. in remote areas with low growth potential) over the long-term. Transmission must-run (TMR) may be an appropriate solution in those limited cases.

Where TMR is used, the cost of TMR (or similar) arrangements should be recovered from load customers in the same manner as wire costs as part of the transmission tariff. In the few cases where transmission constraints are not removed, TMR arrangements should not set or distort market prices. Rather TMR contracts should be provided on a cost-of service basis by the owner and should not be a vehicle for exercising market power in a region that is transmission deficient.

8. **Transmission internal to Alberta should be reinforced so that under normal conditions, the existing inter-ties can import and export power on a continuous basis, in accordance with their design capability.**

The design capability is defined as the maximum level at which the inter-ties can be operated, respecting NERC and WECC reliability criteria and without the use of must run generation.

Under normal conditions, the Alberta transmission system should be reinforced so that the BC Inter-tie is capable of transferring about 1,000 MW for exports subject to availability of generation RAS schemes and about 800 MW for imports subject to suitable load RAS schemes. Imports in excess of 800 MW on the BC Inter-tie require more careful consideration since they may place the Alberta system at considerable risk. The Saskatchewan Inter-tie should be capable of transferring 150 MW for import and export.

Inter-ties are an essential part of a competitive market both as a means to import power when needed, and to export surplus energy and to support effective functioning of the wholesale market. Without such capabilities, market signals and wholesale prices are distorted and unreflective of true market conditions. Since the ability of inter-ties to exchange electricity in both directions (i.e. import and exports) is essential to a robust wholesale market and a reliable electric system, the cost for internal reinforcements and RAS arrangements to allow the inter-ties to function as designed will be allocated to load.

It is recognized that a combination of market design and exercise of market power have constrained the use of inter-ties through BC. Alberta will continue with its efforts to ensure compatibility with its neighbouring jurisdictions and to address access issues with BC Hydro transmission and the Pacific Northwest. Alberta Energy will also continue to participate in RTO and related discussions to ensure Alberta's interests are represented appropriately. However, due to the length of time needed for transmission upgrades, required upgrades to the internal transmission network must not be held in abeyance awaiting resolution of access issues with BC/US markets.

Inter-tie Pricing

The current practice of charging exporters who use non-firm transmission service (i.e. opportunity service) is appropriate. The opportunity export tariff will continue to recover a portion of the embedded costs of transmission wires, losses and ancillary services, while respecting the established practices for inter-regional electricity trade. Such non-firm transmission service should be priced at a discount from the firm transmission service rate. Firm export service may also be developed, with the expectation that this service will be priced at the same level as firm service in Alberta.

Alberta Energy also confirms that import variable charges will be removed coincident with discontinuation of the STS variable energy charge for generators. Loss charges will continue to apply to exporters and importers.

9. **Projects primarily intended for export should be considered on a case-by-case basis. Pricing for such projects would normally be paid by the project beneficiaries (i.e. the exporters). Where residual benefits to the internal grid are demonstrated, consumers may fund system upgrades, in a manner consistent with the benefits.**

   The ISO will be responsible for bringing forward such applications to the EUB in conjunction with project proponents. For dedicated export projects, it is expected that project proponents will be responsible for the costs. The project proponents will be responsible to demonstrate any residual benefits to the Alberta market. Upon demonstration of these benefits, commensurate sharing of costs may occur with load customers in Alberta.

   The regulated framework for transmission should also allow development of "merchant" transmission lines, involving Direct Current (DC) lines to export power over long distances and across borders on a fee-for-service basis. Open access to merchant transmission lines should be available to market participants subject to an auction or other transparent process.

5. Next Steps

Alberta Energy is committed to a consultative process to develop and implement the transmission policy. After consideration of comments and input, a response matrix providing stakeholder comments and Alberta Energy response to those comments was circulated to stakeholders on October 30, 2003.

This policy paper contains foundation principles, recommendations and supporting rationale for a sustainable transmission development policy for Alberta. Various implementation details will be addressed during drafting of a new transmission regulation. The regulation development process will follow the normal and well-developed consultation process with stakeholders and a draft transmission regulation will be available for stakeholder review in December 2003.

6. Appendix

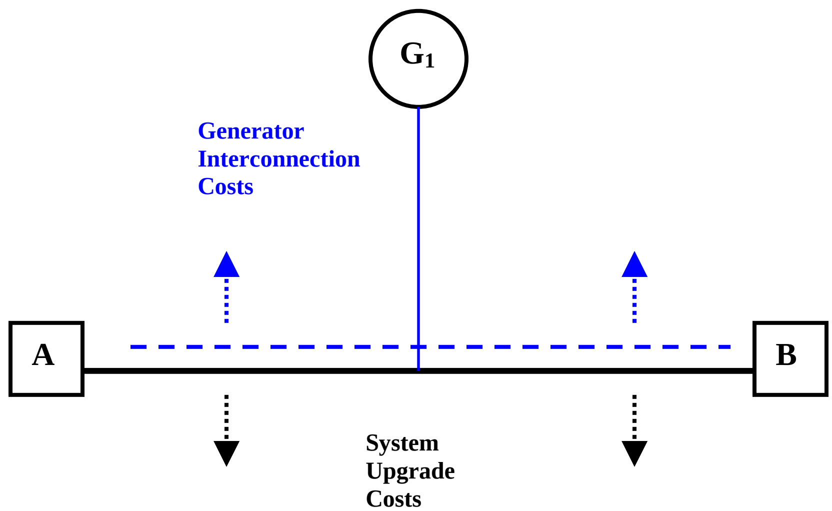
In this section, aspects of the transmission policy related to the generator system contribution payment, losses, real-time congestion management and ownership of transmission facilities are discussed and further illustrated.

6.1. Generator System Contribution Payment

The foundation principles for the Generator System Contribution Payment (**SCP**) are articulated in the body of the policy document. The following discussion is intended to illustrate how the **SCP** may be applied to new generators.

In general, there are three typical categories of costs associated with connecting a generator to the transmission system; (a) direct local interconnection costs (b) local system upgrades and (c) deep system upgrades.

The direct interconnection costs include the line and facilities required to interconnect a generator. Generators will continue to pay all direct local interconnection costs. In general, "system" upgrades include only facilities at or beyond the point where the generator interconnects to the TFO's system. This is illustrated below, where Generator G_1 will be responsible to fully pay for the direct interconnection between G_1 and Line A-B to connect the generator to the transmission system.



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.

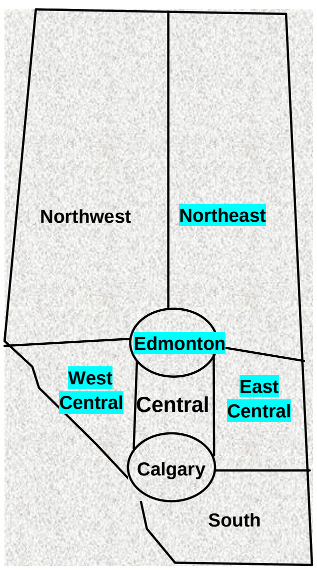
The **SCP** is intended to recover both a portion of the local system costs and deep system costs. The **SCP** will be structured in two parts: a minimum interconnection charge $\mathbf{SCP_M}$ and a location-based charge $\mathbf{SCP_D}$.

The minimum interconnection charge $\mathbf{SCP_M}$ is intended to be an appropriate minimum charge for all new generators who connect to the transmission system. $\mathbf{SCP_M}$ will be the same charge for all new generators. For example, given a $\mathbf{SCP_M}$ of \$10,000/MW, a 100 MW generator would be responsible for an upfront payment of $ 1,000,000. **SCP_M** will be determined by the ISO and approved by the EUB and will apply to all new generators.

The location-based charge **SCP_D** will apply to new generators that locate in regions that are surplus where generation is greater than load. In regions where area generation is less than area load, the **SCP_D** will not apply. The logic is that in regions where area generation is greater than area load, the generator needs the transmission system to get its product to market and should pay some contribution based on that use. **SCP_D** will be determined by the ISO and approved by the EUB and will apply to all new generators.

In general terms, **SCP_D** will be based on the generator's size and location relative to load in other zones. The **SCP_D** calculation is intended to be simple and broadly assess the impact and cost responsibility for burden placed on the transmission system by a generator who locates in a surplus area. The **SCP_D** methodology is further described below.

Zones will be established to determine; (a) relative amount of load and generation in each zone (b) which zones are surplus and (c) the relative distance between injection and load zones. For illustration purposes, the province has been divided into eight (8) zones as shown below.



(1) Zone	(2) Load in Zone	(3) Generation in Zone*	(4) Net Generation in Zone	(5) Zone Surplus? (G > L)	(6) Net Load in Zone	(7) Net Load Distribution Factor **
Calgary	1,892 MW	682 MW	-1,210 MW	N	1,210 MW	42%
Central	774 MW	361 MW	-413 MW	N	413 MW	14%
East Central	602 MW	1,080 MW	+485 MW	**Y**	0 MW	0%
Edmonton	1,892 MW	4,126 MW	+2,234 MW	**Y**	0 MW	0%
Northeast	946 MW	1,000 MW	+ 54 MW	**Y**	0 MW	0%
Northwest	1,204 MW	641 MW	-563 MW	N	563 MW	20%
South	1,032 MW	360 MW	-683 MW	N	683 MW	24%
West Central	258 MW	367 MW	+109 MW	**Y**	0 MW	0%
Total Load	**8,600 MW**	**8,600 MW**			**2,869 MW**	

*Installed generation in a region is normalized to total peak load to approximate in-merit units.
**Net load distribution factor is the ratio of net load in a zone to the sum of all net loads.

This analysis shows that the East Central, Edmonton, Northeast and West Central zones are surplus therefore a **SCP_D** would apply to generators who locate in any of these zones.

For simplicity, it is assumed that a generator located in a surplus zone notionally delivers its energy to areas that are deficient in generation (i.e. net load zones). The MW-km contribution from a generator in a surplus zone will be related to the distance to each net load zone and the ratio of zone net load to the sum of all net loads (i.e. net load distribution factor in column (7) above). For instance, a generator located in a surplus zone (i.e. East Central, Edmonton, Northeast and West Central) would deliver its energy in the following proportions to net load zones: 42 % to Calgary, 14 % to Central, 20 % to Northwest and 24 % to South.

The distance between load zones can be estimated from the center of each zone as shown below:

Distance Between load Zones

Kilometers	TO							
FROM	Calgary	Central	East Central	Edmonton	Northeast	Northwest	South	West Central
Calgary	0	136	259	278	654	616	169	245
Central	136	0	176	141	513	489	292	132
East Central	259	176	0	174	447	551	358	254
Edmonton	278	141	174	0	381	386	428	104
Northeast	654	513	447	381	0	362	781	447
Northwest	616	489	551	386	362	0	779	362
South	169	292	358	428	781	779	0	419
West Central	245	132	254	104	447	362	419	0

EXAMPLE:

The following example illustrates how SCP may be applied in practice. A developer proposes to locate a 180 MW cogeneration plant in the Northeast zone. The Northeast Zone is a surplus zone and would therefore be subject to a $\mathbf{SCP_{D.}}$

The load-distance component (MW-km) of $\mathbf{SCP_D}$ is determined by the product of the distance of the injection zone to each net load zone and the net load distribution factor (as per column (1) below). This establishes a MW-km relationship between the Northeast zone and other net load zones as shown below:

	Generator in Northeast Zone		
	(1) Net Load Distribution Factor	**(2) Distance to Net Load Zones**	**(1) X (2) Load-Distance (km)**
Calgary	42%	654 km	277 km
Central	14%	513 km	74 km
East Central	0%	-	-
Edmonton	0%	-	-
Northeast	0%	-	-
Northwest	20%	362 km	71 km
South	24%	781 km	186 km
West Central	0%	-	-
Total			**607 km**

The MW-km relationship between all surplus zones is shown below:

Injection Zone	East Central	Edmonton	Northeast	West Central
Calgary	110	118	277	104
Central	25	20	74	19
East Central	-	-	-	-
Edmonton	-	-	-	-
Northeast	-	-	-	-
Northwest	108	76	71	71
South	85	102	186	100
West Central	-	-	-	-
Total Load-Distance	**328**	**315**	**607**	**293**
Per Unit Load-Distance	**0.54**	**0.52**	**1.00**	**0.48**

The use of $\mathbf{SCP_D}$ is not intended to be overly burdensome or discourage generation additions. To recognize this and to ensure that there are no unintended consequences, $\mathbf{SCP_D}$ should be limited to four times $\mathbf{SCP_M}$.

The Northeast zone is most remote of all zones therefore it should attract the maximum $\mathbf{SCP_D}$ on the system. If the $\mathbf{SCP_M}$ is set to $10,000 per MW and if the maximum $\mathbf{SCP_D}$ on the system is limited to no more than four times $\mathbf{SCP_M}$ then the Northeast zone $\mathbf{SCP_D}$ would be $40,000 per MW.

Therefore, a 180 MW cogeneration plant in the Northeast zone would be responsible for a $7.2 million $\mathbf{SCP_D}$ payment. The $7.2 million SCP would be refunded to the generator over 10 years from the commercial operation date, subject to satisfactory operation. Subject to satisfactory credit arrangements the SCP may be made over time, in which case the refunds will offset the payments.

Since $\mathbf{SCP_M}$ is intended as a minimum, the generator should not pay both $\mathbf{SCP_M}$ and $\mathbf{SCP_D}$ but instead pay the greater of $\mathbf{SCP_M}$ or $\mathbf{SCP_D}$. In our example, if $\mathbf{SCP_M}$ is $10,000 per MW, then the most any generator would pay under any circumstances would be $ 40,000 per MW.

The following table illustrates applicable SCP payments for 180 and 400 MW generating units located in various zones in the province

Zone	SCP	Example SCP values	
		180 MW	400 MW
Calgary	$10,000/MW *	$1.8 M	$ 4.0 M
Central	$10,000/MW *	$1.8 M	$ 4.0 M
East Central	$21,600/MW	$3.88 M	$ 8.64 M
Edmonton	$20,800/MW	$3.744 M	$ 8.32 M
Northeast	$40,000/MW	$7.2 M	$ 16.0 M
Northwest	$10,000/MW *	$1.8 M	$ 4.0 M
South	$10,000/MW *	$1.8 M	$ 4.0 M
West Central	$19,200/MW	$3.456 M	$ 7.68 M

* Subject to $\mathbf{SCP_M}$ minimum charge

6.2. Real Time Congestion Management

As noted in the policy paper, the ISO will be required to develop, in consultation with stakeholders, a system for managing real time congestion that may occur during abnormal conditions. The intended application of real-time congestion management is discussed in this section.

In general terms, real-time congestion should be resolved by merit order re-dispatch, followed, if necessary, by pro-rata curtailment of parties with equivalent offers or bids. The real-time congestion program should use a reverse merit order to dispatch down units in a congested area, with units not in merit order being paid as bid so that congestion costs are not reflected in the system marginal price. In principle, real-time congestion or constraints should not alter or distort market prices.

The following actual example illustrates how a real-time congestion scheme may inappropriately distort the system marginal price. This shows a dispatch scenario where 90 MW of energy (2 blocks) is unavailable for dispatch due to transmission congestion. As shown below, the dispatch moves up the merit order by 90 MW in order to replace the energy, which cannot be delivered due to transmission congestion. As a result, the system marginal price is distorted from \$91.82 to \$485.77. This creates an inappropriate congestion cost of \$3.1 million when the increase in Pool Price is applied across all loads in the province (\$485.77 - \$91.82 X 7,984 MWh/h = \$3,100,000).

Example – Impact of Congestion on SMP

Offer Block	Offer Price	MW Volume
103	800	9
102	778	2
101	550	0
100	500	9
99	485.84	31
98	485.83	40
97	485.8	155
96	485.78	45
95	485.75	15
94	130	30
93	122	10
92	108.5	12
91	105	10
90	94.47	43
89	85	13
88	80	50
87	76	50
86	61.02	30
85	58.73	25
84	54.87	25
83	53.95	65
82	48.62	0
81	34.35	10
80	34.06	13
79	33.25	5

Pool Price Set by Congestion

\$ 485.77

+ 90 MW Dispatch
due to congestion

\$ 91.82

Pool Price not set by Congestion

Offer Blocks 83 and 84 are undeliverable
due to transmission congestion

Congestion Cost: = \$485.77-\$91.82 x 7984 MWh

= \$ 3,145,297

The distortion in the system marginal price may be avoided if generators dispatched out of merit are paid their offer price less the system marginal to relieve the congestion. The system marginal price therefore remains at the level it would have been at without congestion and generators dispatched out of merit are “kept whole” and are provided their offer price less the Pool Price for the energy provided. The cost incurred to initiate the out of merit dispatches would then be in the order of \$25,000 (see below).

Payment = (Offer Price – Pool Price) X Offer Volume

Block 96	\$ 17,728.20
Block 95	\$ 5,908.95
Block 94	\$ 1,145.40
Block 93	\$ 301.80
Block 92	\$ 200.16
Block 91	\$ 131.80
Total	\$ 25,416.31

These costs would be recovered from loads in the same manner as other transmission costs.

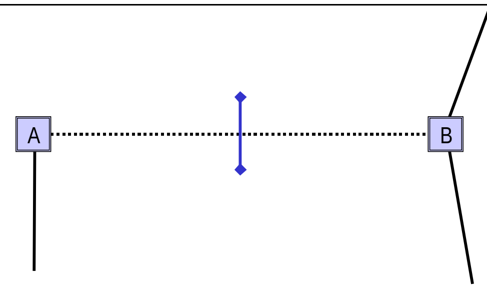
6.3. Ownership of Transmission Facilities

As noted previously, all new transmission facilities, including radial interconnection facilities, will be direct-assigned to the incumbent TFO's. Projects involving connections or upgrades to existing transmission facilities or use of existing right-of-ways will also be direct assigned to the incumbent TFO to ensure safe and reliable service.

The ISO will be required to create rules and processes respecting ownership of new facilities where new facilities involve multiple TFO's. It is expected that the ISO will develop these rules and processes in concert with the TFO's however, the following examples are intended to provide further guidance on this matter.

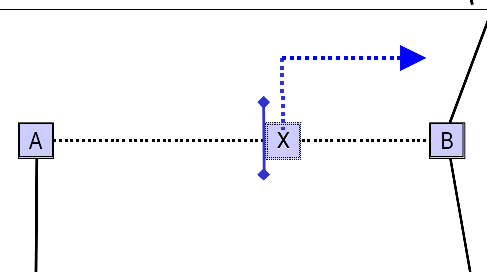
1.New Line Connecting 2 TFO's

- Substations A and B are owned by different TFO's. The TFO's will share 50/50 ownership of Line A-B.
- If the substations are owned by one TFO, Line A-B will be 100% owned by that TFO.



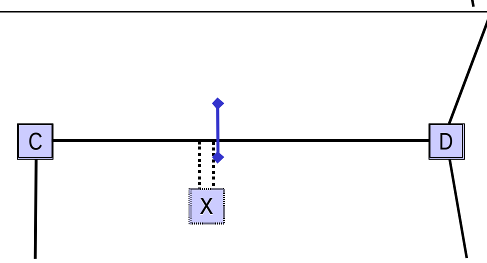
2. New Line connects TFO's with substation in line

- TFO's will share 50/50 ownership of Line A-B.
- Substation X interconnects with system and facilities of TFO B, therefore TFO B will be assigned Substation X.



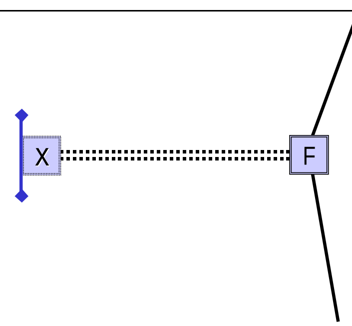
C. New substation in existing line

- If Line C-D is owned by one TFO, current TFO will own substation X and new lines required to interconnect
- If Line C-D ownership is split in the middle, TFO that owns Substation C will own Substation X and tap unless substation X ties back into the system of the other TFO (as per 2 above).



D. New Radial or Double Radial Line and Substation

- Interconnecting TFO will own line and substation if the substation serves distribution load or is expected to be serving distribution load
- If the line is to serve a generator, the incumbent TFO, who owns and operates Substation F will own Substation X and interconnecting lines



Competitive procurement of transmission facilities will therefore be suspended indefinitely. Notwithstanding, there may be some circumstances, where the ISO may consider competitive procurement. However such a process should not be initiated in advance of establishment of clear standards (planning, design, operations and maintenance) and standard commercial agreements, which have been approved by the EUB. In addition, the ISO must be convinced that there are compelling benefits for a specific project to proceed in this manner.

The ISO, TFO's and the EUB should also consider improvements to the direct-assignment process. These improvements may include; more visible and meaningful performance standards and measures, cost and quotation templates, standards, specifications and milestones for projects. The ISO should lead industry efforts to evaluate and incorporate these improvements and to establish transmission performance standards and measures.

6.4. Losses

The foundation principles for recovery of transmission losses are articulated in the body of the policy document. The application of loss factors is further described in this section.

The loss charge is intended to provide generators a long-term siting signal, which generally reflects desirable and less desirable locations on the transmission system with respect to transmission losses. The loss signal should therefore be stable, predictable and broadly reflective of losses in order to allow it to be factored into investment decisions.

The loss factor should apply for a reasonable period of time (e.g. 5 years) and the factor should not vary significantly when it is updated. In this respect, adjustments to an area loss factor should not vary by more than about 50 % of the system average losses. Given average system losses of about 5 %, area loss factors should not change by more than about 2 to 3 % when they are updated.

The same loss factor should apply to all generators (old and new) in a zone – the loss factor should not be affected by the actions of other generators in a zone.

The current range of loss factors is extreme and ranges from about +10 % to about -20 % (overall range of 30 %) across the province. A more reasonable range for loss factors would be in the order of 3 times the system average losses. Assuming system average losses of about 5 %, the overall range for losses should therefore be about 15 % (i.e. +5% to -10%).

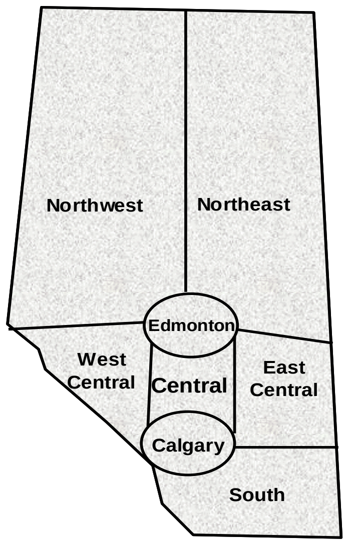
Long term loss reduction

The ISO should proactively pursue transmission projects that will reduce overall transmission losses in the long term to the benefit of all consumers, as consumers ultimately pay for losses through their energy price.

Cost Recovery

The ISO will be required to establish a calibration factor to ensure the actual cost of transmission losses will be recovered. In principle, it is not necessary for the costs to precisely match cost causation. In general, the ISO should set and adjust the calibration factors as necessary to minimise over or under recovery of losses. Any account balances will be brought forward to the next forecast period without retroactive adjustments to loss factors or payments.

The following example illustrates how transmission loss factors may be applied in practice. For illustration purposes, a series of loss zones are created across the province. The loss factors will apply to all generators located in the zone. As shown below, the range of loss factors will not exceed 3 times the system average. Therefore, the loss factor will range between about +5% and -10%.

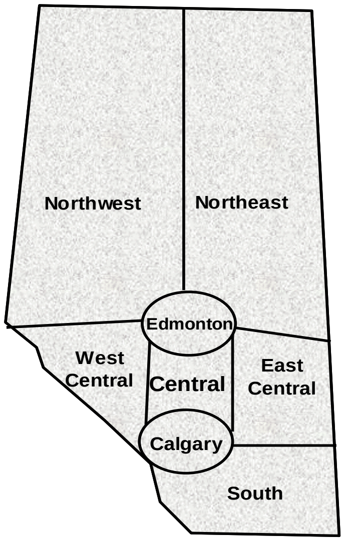


Generator Loss Factors (Years 1-5)

Zone	Zonal Loss Factor (Z)	Calibration Factor (C)	Final Loss Factor L = Z + C
Calgary	5%	-1% (year 1)	4%
Central	0%		-1%
East Central	-2%		-3%
Edmonton	-5%		-6%
Northeast	-10%		-11%
Northwest	+5%		+4%
South	+2%		+1%
West Central	-5%		-6%

Loss factors will be established every 5 years and remain fixed for that period. New generators entering a zone will receive the posted loss factor, which applies to all generators in the zone (new and existing). When the loss factors are re-established at the end of their 5-year period, the loss factor in a particular region may not change by more than one half of the system average losses (i.e. 2.5 % with system average losses of 5 %). This will allow loss factors to be revised as system conditions change while providing reasonable and predictable loss factors, which can be factored into generator investment decisions.

In the following table, the generation loss factors are shown for years 6 to 10. This table illustrates how loss factors may be adjusted at the expiration of the first five-year term. In this case, significant load growth in the Northwest has precipitated system reinforcements from the Northeast, which has altered flows and losses. In the next forecast period (Years 6-10), the system average losses are reduced to 4.5% due to system reinforcements. The loss charge in the Northeast has been reduced from - 11% to - 8 % and the loss factor credit in the Northwest has been reduced from +4 % to + 2%. The rate of change for each zone has been limited to about 2-3 % to be within about one half of the system average losses.



Generator Loss Factors (Years 6-10)

Zone	Zonal Loss Factor (Z)	Calibration Factor (C)	Final Loss Factor L = Z + C
Calgary	+4.5%	-0.5% (year 6)	+4%
Central	0%		-0.5%
East Central	-1.5%		-2%
Edmonton	-4.5%		-5%
Northeast	-7.5%		-8%
Northwest	+2.5%		+2%
South	+1.5%		-1%
West Central	-4.5%		-5%