Participant-Related Costs for DFOs (Substation Fraction) and DFO Cost Flow-Through Technical Session(s)

Background

Alberta's interconnected electric system has traditionally been operated on the basis of the one-way delivery of electrical energy.[1] Under the one-way construct, DFOs supply end-use customers with electrical energy that is produced by centrally-located generation plants and received from the transmission system at distribution facility owner ("DFO") contracted substations.[2]

In the AESO's view, Alberta's electricity industry must prepare for a shift from the traditional one-way construct to a more frequent and highly variable two-way flow of power.[3] With increasing amounts of distribution-connected generation ("DCG") driving this shift, current ISO tariff provisions and processes should be re-evaluated to ensure that transmission system costs are being properly allocated.

The following tariff-related issues and statements have been identified by the AESO and stakeholder for evaluation:

- As a result of the increase of DFO-contracted substations that serve both load *and* generation (resulting in two-way flow to and from the transmission system):
    - System access service provided at DFO-contracted substations should reflect the fact that these substations facilitate the flow of power both to and from the transmission system
    - The AESO's practice of calculating and applying the substation fraction originated as a way to reflect the straightforward scenarios of one-way flow, or two-way flow proposed from day one at a substation (as opposed to two-way flow resulting from the *subsequent addition* of DCG)
- Although the ISO tariff contemplates the two-way flow of energy at dual-use industrial sites, the decision to add generation at a DFO-contracted substation is made for different reasons. Additionally, the decision to add DCG is generally made *after* the DFO-contracted substation is built.
    - The ratio of load and generation at a DFO-contracted substation does not recognize that a ratio-based allocation of costs may not always reflect the actual drivers of those costs

---

[1] Proceeding 22534, Alberta Electric Distribution System – Connected Generation Inquiry, Final Report, December 29, 2017, at paras. 57, 59 and 62.

[2] Proceeding 22534, Alberta Electric Distribution System – Connected Generation Inquiry, Final Report, December 29, 2017, at para 57.

[3] Exhibit 24116-X0176, Distributions System Inquiry Module One, AESO Submission, July 17, 2019.

Alberta Electric System Operator
Calgary Place, 2500, 330-5th Avenue SW Calgary, AB T2P 0L4
Phone: 403-539-2450 | Fax: 403-539-2949
www.aeso.ca
@theaeso

- The ISO tariff and associated tools, including the Construction Contribution Decision ("CCD"), are not and were not designed for the addition of DCG at DFO substations that supply end-use customers

- The allocation of transmission facility costs after a locational investment decision has been made is ineffective and unfair
  - DCGs cannot respond to a price signal after the locational decision has been made
- The potential allocation of costs to DCG as a result of the ISO tariff and cost flow-through by DFOs may not be efficient or transparent
  - DCGs may not be aware of the allocation of costs early enough to respond to this price signal. As the DFO holds the Rate STS, *Supply Transmission Service* ("Rate STS") contract, it is responsible for determining the allocation of ISO tariff charges to DCGs in accordance with its applicable distribution tariff[4]
  - The price signals from the ISO tariff and subsequently, the DFO tariff through to the DCGs and other DFO end-use customers may not be aligned and are not transparent

Decision 22942-D02-2019

On Sept. 22, 2019, the Alberta Utilities Commission ("Commission") issued Decision 22942-D02-2019 ("Decision") regarding the application of the Independent System Operator, operating as the AESO, for approval of the proposed 2018 ISO Tariff.

In the Decision, the Commission approved the implementation of the AESO's proposed adjusted metering practice. The Commission found that:

a) the adjusted metering practice is consistent with applicable legislation,[5] and

b) DCG requires access to and obtains benefits from the transmission system and therefore it is reasonable to allocate transmission system costs to DCG, pursuant to applicable legislation with respect to the allocation of costs to supply transmission service market participants.[6]

In connection with the adjusted metering practice, the Commission held that "[the] substation fraction formula is a long-established mechanism used by the AESO to allocate the costs of local interconnection facilities that may have joint use". The Commission stated that while it considers the use of a ratio of STS and DTS contract capacities as a percentage of the combined DTS and STS contract capacities to be a relatively simple mechanism for the allocation of local interconnection facility costs, it is not unreasonable in the absence of any other information. The Commission found that no parties in Proceeding 22942

[4] Exhibit 22942-X0558, AESO argument, paragraph 90.

[5] Decision 22942-D02-2019, para 844.

[6] Decision 22942-D02-2019, para 844.

“provided any evidence suggesting that a mechanism other than the substation fraction formula would be an improvement for this purpose.”[7]

In response to concerns expressed by a CGWG witness during the oral hearing that DCG developers would be subject to ongoing risk that costs of future DFO substation upgrades will be flowed to them via substation fractioning,[8] the Commission found that the expectation arose from Fortis’ interpretation of the *Transmission Regulation* that it is required to flow through local interconnection costs to DCG.[9]

The Commission held that a DFO is not legislatively required to flow through substation fraction amounts to DCG. Specifically, the Commission found “that DFOs have discretion to limit the amount of AESO contributions flowed through to DCGs through the application of the substation fraction to future DFO substation upgrade projects by retaining some or all of this cost.”[10]

Review and Variance Applications

On Nov. 21, 2019, the Community Generation Working Group (“CGWG”) filed with the Commission in Proceeding 25101 an application to request a review and variance (“R&V”) of certain of the Commission’s findings in the Decision related to the AESO’s substation fraction formula.[11]

The CGWG asserts in its R&V application that the Commission made the following errors in the Decision:

- The Commission incorrectly found that no parties provided any evidence suggesting that a mechanism other than the substation fraction formula would be an improvement for the purpose of allocating costs between DFO load and DCG;[12] and

- The Commission incorrectly characterized the substation fraction formula as the AESO proposed it pursuant to the 2018 ISO Tariff as a “long-established mechanism”.[13]

The CGWG also asserts that the Commission misinterpreted, omitted or otherwise failed to consider evidence on the record of Proceeding 22942 that demonstrated that the formula for what the CGWG characterizes as the “2019 Substation Fractioning Methodology” is not the same formula as the substation fraction formula used in respect of previous ISO tariffs and is, necessarily, not the same mechanism.[14]

[7] Decision 22942-D02-2019, para 742.

[8] Decision 22942-D02-2019, paras 821 and 822.

[9] Decision 22942-D02-2019, para 823.

[10] Decision 22942-D02-2019, para 824.

[11] Exhibit 25101-X0002.

[12] Exhibit 25101-X0002, para 4(a).

[13] Exhibit 25101-X0002, para 4(b).

[14] Exhibit 25101-X0002, para 5(b).

The CGWG submits that the recalculation of transmission cost allocation to DCG due to subsequent substation upgrades results in future cost uncertainty for DCG.[15]

On Nov. 21, 2019, Fortis filed in Proceeding 25102 an application with the Commission to request an R&V of certain findings made by the Commission in the Decision, also related to the AESO's substation fraction.[16]

Specifically, Fortis takes the position that the Commission made the following errors in the Decision, among others:

- It incorrectly held that DFOs have the discretion to limit the amount of AESO contributions flowed through to DCGs via the substation fraction by retaining some or all of the costs;[17] and
- It failed to appreciate that it is the AESO's application of the substation fraction, not the adjusted metering practice that results in DCGs facing unexpected costs.[18]

On December 16, 2019, the AESO requested that the Commission allow the AESO to host technical session(s) for DGs, DFOs, Commission staff and other interested stakeholders to attend and participate, in order to facilitate:

- a common understanding of the purpose and application of the substation fraction formula;
- agreement on high-level principles applicable to the substation fraction formula including, for instance, cost certainty for DCG, parity between TCG and DCG regarding local interconnection costs, and certainty for DFOs regarding the flow-through of costs to be attributed to DCG; and
- a common understanding of the financial impacts associated with the substation fraction and any associated flow-through of local interconnection costs to different stakeholder groups, including DCG, TCG, DFOs, and ratepayers.

The Commission approved the AESO's request by way of a ruling issued on January 15, 2020, and found it to be in the public interest to suspend both Proceedings 25101 and 25102 to enable participants to explore issues with the AESO, with the objective of filing a joint submission for consideration by the Commission.[19]

Common understanding of current legislation, ISO tariff and processes

In accordance with section 47 of the Transmission Regulation ("Regulation"), load are required to wholly pay for the costs of the transmission system. These costs include non-radial and networked transmission

[15] Exhibit 25101-X0002, para 51.

[16] Exhibit 25102-X0002.

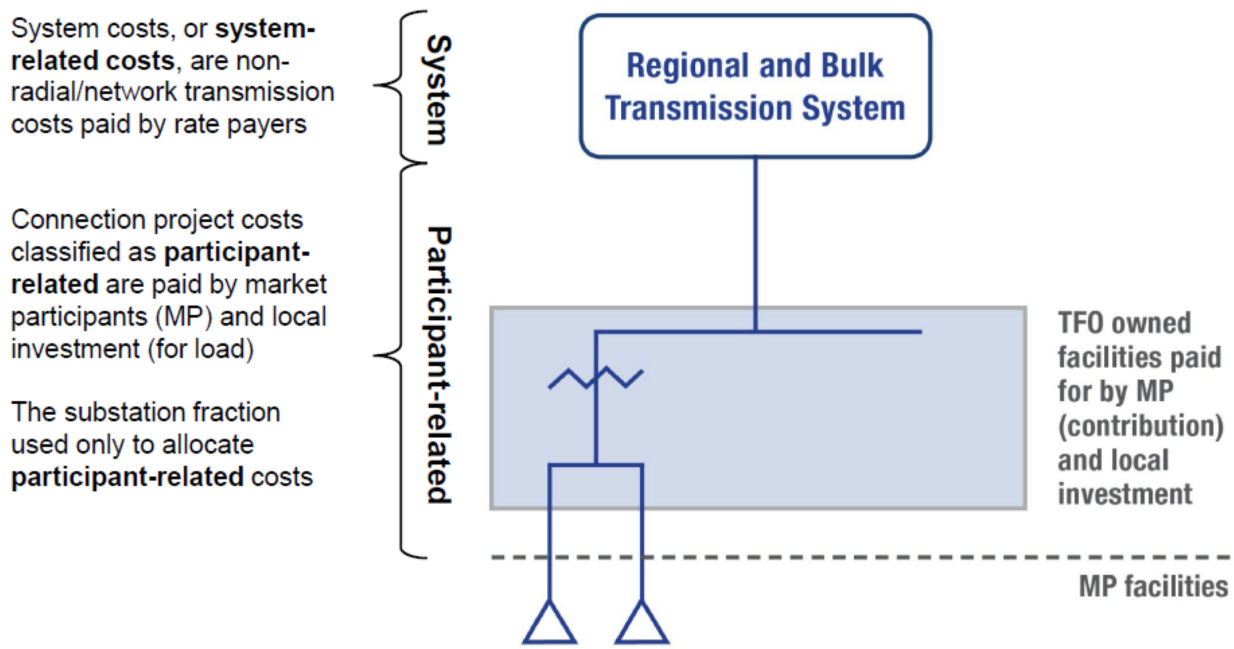
[17] Exhibit 25102-X0002, paras 2(a) and 10.

[18] Exhibit 25102-X0002, paras 2(b) and 21.

[19] Exhibit 25101-X0037 at para. 9.

facility costs, which are paid monthly through the Rate DTS, *Demand Transmission Service* ("Rate DTS") charge, specifically the bulk system, regional system and point-of-delivery ("POD") charges.

Figure 1: System versus participant-related costs



In contrast to non-radial and networked transmission facility costs, participant-related costs are generally the costs of radial transmission facilities, and are covered through an upfront construction contribution payment by the DFO, load or generation market participant that is seeking to obtain new or increased system access service.. In the case of demand-related costs, local investment is applied, as per the ISO tariff, as an offset to the upfront construction contribution payment.

DFOs pay for the just and reasonable costs of the transmission system, to the extent required by the ISO tariff. DFOs do not pay "local interconnection costs" as described in Section 28(1) of the Regulation but do pay participant-related costs.[20]

As laid out in Section 47 of the Regulation, the owners of generating units do not pay for the non-radial or networked costs of the transmission system. Instead, the owners of generating units pay for the following:

1. Participant-related costs, fully paid by an upfront construction contribution payment as local investment is not available to supply-related costs. These costs are otherwise known as "local interconnection costs";
2. Generating unit owner's contribution ("GUOC") through an upfront contribution payment and is refundable over time based on the generator's performance;[21] and

---

[20] Decision 22942-D02-2019 at para. 744.

Public

3. Line losses recovered through Rate STS, *Supply Transmission Service* ("Rate STS") monthly charges.

System transmission projects or connection projects

When the AESO directs a transmission facility owner ("TFO") to construct or upgrade the transmission system, the TFO incurs the costs of doing so and, subject to the Commission's approval, recovers those costs through TFO charges to the AESO.

The AESO recovers system transmission project costs for the bulk and regional transmission system through Rate DTS system access service provided to load customers. In this way, market participants taking service under Rate DTS pay for the transmission system.

When a market participant wants to connect to the transmission system or to obtain an increased level of system access service, they submit a system access service request ("SASR") to the AESO. The AESO determines how to respond to a system access service request. If the construction of new or altered transmission facilities is required to respond to the request, the AESO will direct a TFO to apply to the Commission for approval to construct and operate the transmission facilities. The costs incurred by the TFO are connection project costs pursuant to the ISO tariff. Connection project costs are essentially the costs of incremental transmission facilities required to connect a market participant or to provide an increased level of system access service. These costs are further subdivided and classified as participant-related and system-related costs.

Connection project cost classification as either participant-related or system-related costs

Connection project costs that are classified as system-related costs are recovered in the same manner as system transmission costs (i.e., from all market participants taking service under Rate DTS).

Connection project costs that are classified as participant-related costs are recovered through a combination of (1) an upfront construction contribution paid by the market participant, and (2) for demand-related costs, local investment as determined by the ISO tariff.

In order to calculate the costs recovered through local investment and upfront construction contribution, the AESO must determine the following pursuant to Section 8, *Construction Contributions for Connection Projects*, of the current ISO tariff:[22]

1. The costs of a connection project must be classified as either participant-related or system-related:
    - Participant-related costs are described in subsection 8.3(2) of Section 8 of the ISO tariff
    - System-related costs are generally those costs that are "non-radial";
2. The participant-related costs are then deemed to be either demand-related or supply-related using the ratio of Rate DTS (demand-related) and Rate STS (supply-related);
3. Local investment is only available to demand-related costs but not to those amounts that are deemed supply-related. (i.e. local investment is only available for load);

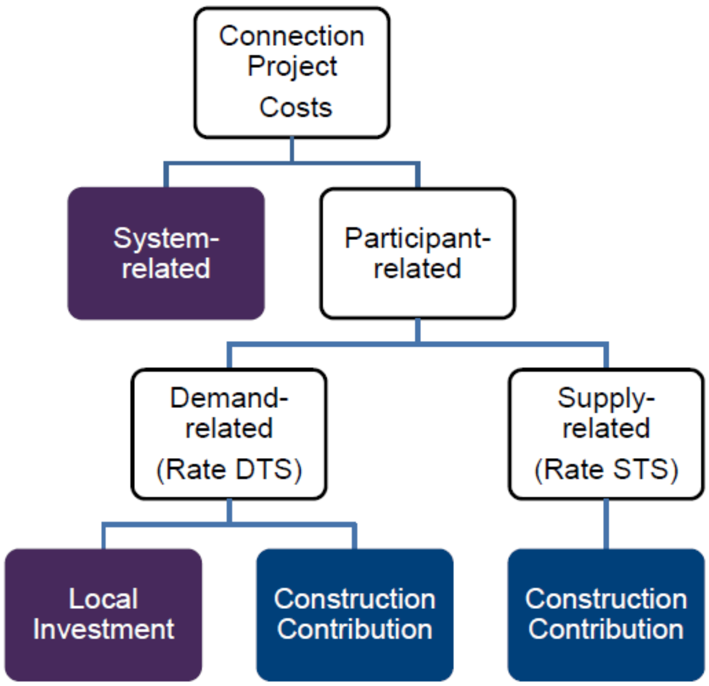
---

[21] As per AESO Rule, Section 505.2, *Performance Criteria for Refund of Generating Unit Owner's Contribution*.

[22] 2019 ISO Tariff, Effective 2019-01-01.

4. The portion of participant-related costs which exceeds the available local investment is paid by the market participant through an upfront construction contribution.

Figure 2: Connection project costs classification



Cost classification for behind-the-fence or contract change projects

A behind the fence ("BTF") project involves a market participant altering their existing facilities already connected to the transmission system; no alterations or additions to existing transmission facilities are required. A BTF project may either (1) include a request to change existing contract capacity or (2) not include a request change existing contract capacity.

A contract change project only involves a request to change existing contract capacity; no additions or alterations of any transmission facilities (either of the transmission system or a market participant's facilities) are required.

A request to change contract capacity (increase, decrease or contract cancellation) as part of either a BTF project or contract change project requires the AESO to review and possibly adjust a previously determined construction contribution.

Table 1: Project type summary

Project type	Alterations to existing transmission facilities?	Construction Contribution Determination
Connection project	Yes. New project costs.	Yes

BTF project • **No contract change** • **Contract change**	 No. No.	 No Yes – adjustment of construction contribution determination
Contract change project	No.	Yes – adjustment of construction contribution determination

Triggers for adjusting a construction contribution for a DFO (single market participant)

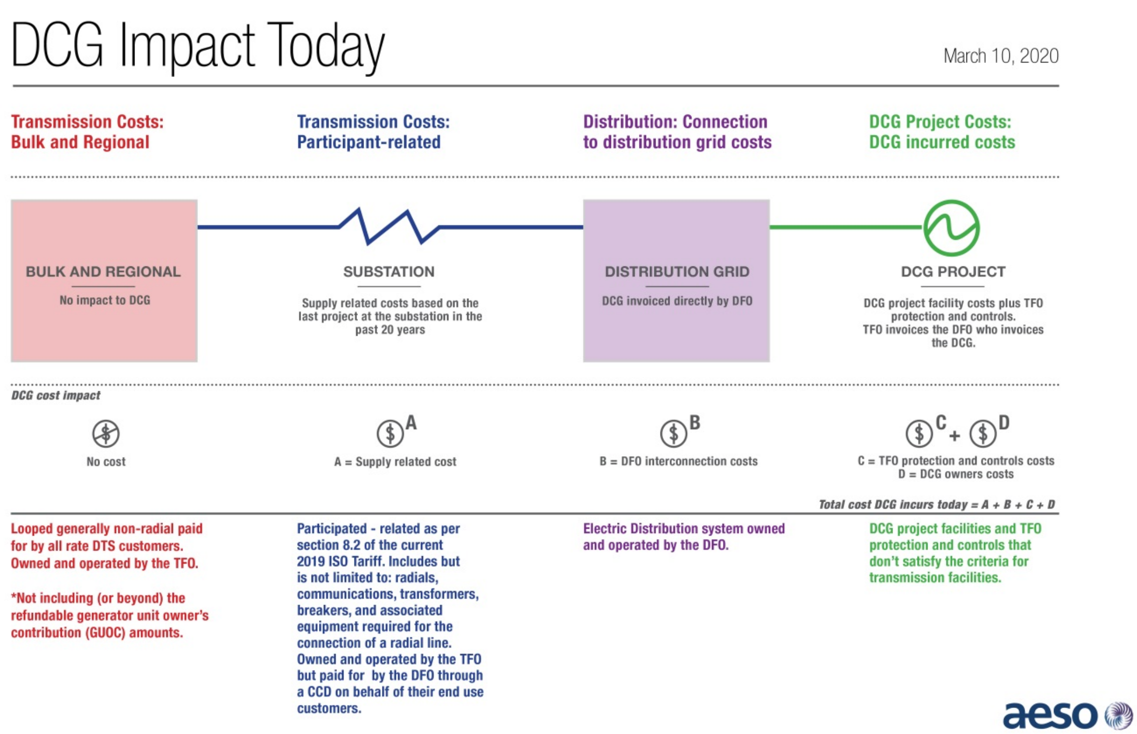
Pursuant to Section 9 of the current ISO tariff, an adjustment to a previously calculated construction contribution for a DFO point of delivery ("POD") substation can be triggered by the following events:

1. Increases or decreases to Rate DTS contract capacity (contract change); and
2. Addition of Rate STS contract capacity (contract change).

A connection project driven by capacity or reliability requirements at that POD, with new or altered transmission facilities, would require a <u>new</u> calculation and not a recalculation of a previously calculated construction contribution.

Distribution and transmission costs faced by DCG

Figure 2: DCG impact today



- **Costs from the DFO - incremental costs to connect to distribution system**

These are the costs the DCG customer pays to the DFO to construct distribution facilities to connect to their electric distribution system. The AESO does not have visibility or purview of these costs.

- **Costs directly from the TFO - protections/controls payable as expenses to the TFO**

These are costs the DCG customer pays directly to the TFO for connecting to the transmission system.

- **Recalculation of a construction contribution if the POD substation has been constructed or upgraded in the past 20 years**

Any market participant taking service under Rate DTS is eligible for local investment based on the contract capacity over a 20 year term. The local investment calculation is based on the contract capacities and the substation fraction.

Table 2: 2020 ISO tariff (interim) – Local investment amounts

Column A	Column B	Column C
Tier	Investment for Service Under Rate DTS	Investment for Service Under Rate DTS with Rate PSC
(c) **Substation fraction** (for new **points of delivery** only)	$105,150/year	$22,080/year
(d) First (7.5 × **substation fraction**) MW of **contract capacity**	$34,600/MW/year	$7,270/MW/year
(e) Next (9.5 × **substation fraction**) MW of **contract capacity**	$20,550/MW/year	$2,890/MW/year
(f) Next (23 × **substation fraction**) MW of **contract capacity**	$13,750/MW/year	$2,890/MW/year
(g) All remaining MW of **contract capacity**	$8,450/MW/year	$0/MW/year

As an example, if a DFO requested a new POD substation with a 10 MW contract capacity, the substation fraction would be 1.0 and the maximum local investment would be available for the full 10 MW.

Adding a Rate STS contract a few years later would reduce the substation fraction from 1.0 which decreases the demand-related costs; the recalculation of local investment (reduction) would require the claw back of some of the previously available local investment (market participant pays additional construction contribution).

- **Costs from the TFO/DFO through the CCD – supply-related portion of participant-related costs**

A CCD includes a calculator that determines the upfront construction contribution required from the market participant. The calculator uses an average substation fraction method to calculate the split of demand-related and supply-related costs for a connection project.

When a DFO submits a SASR to add Rate STS at a POD substation, the calculation and application of the substation fraction is not as straightforward as when Rate STS and Rate DTS are proposed from day one of a dual-use substation. In the former case, the substation fraction needs to consider the different contract capacities at different points in time to reflect the historical use of the substation for demand only. In the latter case, the substation fraction will reflect the portion of supply-related costs from the outset of the dual-use substation.

The AESO adjusted the calculation to account for time and in consideration of two separate customers at one substation. The DFO receives a new CCD and flows the supply-related costs through to the DCG.

- **Costs directly from the AESO – GUOC**

Currently, the AESO creates a CCD for the DFO who in turn collects the GUOC from the DCG.

- **Costs directly to DFO from the AESO – Rate STS monthly losses charge**

Monthly Rate STS charges to the DFO are to cover the location-based cost of losses.

Differences with two market participants vs one market participant, i.e. DFO

The provisions (subsections 6(4) and 6(5) of Section 8) in the current ISO tariff require the AESO to deem costs allocated to a (or one) market participant as either demand-related or supply-related but the ISO tariff only describes the allocation of participant-related costs relating to "shared costs" for "each market participant) in subsections 6(2) and 6(2) of Section 8.

If a market participant at a substation (where a second market participant is connected) requests additional transmission facilities, the AESO determines the connection project costs in response to the requestor market participant and assigns no connection project costs to the other market participants at the substation.

Although, if a market participant requests a contract change at a substation where multiple market participants are connected, a recalculation of the shared costs between the two or more market participants at the substation would occur based on subsection 5 of Section 9 of the current ISO tariff. The AESO notes that the recalculation required over the full twenty year period could result in adjustments to the participant-related costs for each market participant at the substation.

Identified Issues with Cost Allocation

- Adding a Rate STS contract (no construction) to a DFO POD substation changes the substation fraction. In cases when there was construction at the substation in the previous 20 years, this leads to an increase in supply-related costs, where ultimately the DFO pays an additional construction contribution (because of the reduction of local investment)
    - What if no construction?
    - What if last project was a breaker add?
    - What if last project was a transformer add?
    - What if last project was an expensive reliability project?
- A fair allocation of demand and supply-related costs should reflect that DCGs are using DFO facilities previously paid for by distribution rate payers. The reduction of participant-related costs eligible for local investment safeguards against the subsidization
- Recalculation of the demand and supply related costs won't allocate costs to a second DCG at a DFO substation

- When the DCG are adding transmission assets (construction at the substation) the AESO does a CCD for the assets being added (eg/ breaker or transformer). The DFO is charged a contribution (presumably flowed through costs), and GUOC.
    - The AESO also does a recalculation of the previous project (if any in last 20 years) and claws back investment
- Shared cost allocation (more than one market participant) may be more appropriate but also has issues:
    - Current tariff would provide for a shared costs recalculation when one market decreases the original capacity request resulting in contribution amount changes for all market participants at the substation
    - No shared costs if no construction in last 20 years

Principles

It was identified that a principle-based approach would be the most effective way to allow changes, if required, to be assessed and agreed upon by a broad group of customers. The following principles have been proposed and expanded based on stakeholder feedback and discussion:

Overarching

Tariff design and implementation facilitates a fair, efficient and openly competitive market (FEOC)

- Fosters competition and encourages new market entry
- Efficiency
- Avoidance of undue discrimination
- Fairness

Principle 1

Parity between transmission interconnection costs calculation for transmission connected customers and distribution connected customers while enabling effective price signals to ensure the optimal use of existing distribution and transmission facilities

- Fairness
- Effective price signals

Principle 2

Market participants should be responsible for an appropriate share of the costs of transmission facilities that are required to provide them with access to the transmission system (may include paying a contribution towards facilities paid for by other customers and refund to the customer that paid)

- Fairness
- Cost causation

Principle 3

Costs should not be allocated to a DCG customer after the DCG has energized, if the DCG is not directly causing those costs

- Certainty of future costs
- Stability

Principle 4

DFOs should be provided with reasonable certainty re: cost treatment/recovery

- Certainty of future costs
- Stability