Alberta Utilities Commission

FortisAlberta Inc.

Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application

June 7, 2021

Alberta Utilities Commission
Decision 26090-D01-2021
FortisAlberta Inc.
Distribution-Connected Generation Credit Module for Fortis's 2022 Phase II Distribution Tariff Application
Proceeding 26090

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1 Decision summary

1. The Alberta Utilities Commission has determined that the existing distribution-connected generation (DCG) credit mechanism within ATCO Electric Ltd., ENMAX Power Corporation and FortisAlberta Inc.'s respective tariffs will be discontinued. The provision of the DCG credit mechanism does not support just and reasonable ratemaking because it unnecessarily increases the payments ratepayers[1] make for transmission service, and these additional payments are not offset by a proven quantifiable benefit to the ratepayers. Furthermore, the provision of the DCG credit mechanism is not just and reasonable because it promotes an unlevel playing field between generators, resulting in distortionary harm to the wholesale electricity market, which is also a detriment to ratepayers.

2. The Commission has determined that a four-year transition period, set on a declining basis, for the Rate DTS (demand transmission service) portion of the DCG credit mechanism balances the competing public interest objectives in discontinuing it. The Rate STS (supply transmission service) portion of the DCG-related tariff is to be calculated as per usual with no change (i.e., flow through of the Alberta Electric System Operator's (AESO) Rate STS credits or charges).

3. This decision provides the Commission's reasons for these determinations.

2 Background and procedural summary

4. In this proceeding, the Commission asked for submissions on the following:

(i) Should the Commission continue to approve the existing DCG credit mechanism in Fortis, ATCO Electric and ENMAX's respective distribution tariffs?

(ii) Should consideration be given to adjusting the existing DCG credit mechanism? If so, based on what criteria and for what purpose?

(iii) If these credits are to be retained as presently constituted or in an alternative form, comment on level-playing field considerations between DCG and transmission-connected generation (TCG).

(iv) If DCG credits are adjusted or eliminated, what issues should be examined, including the scope and timing of any adjustments?

1 The terms "ratepayer," "consumer" and "load customer" are used interchangeably in this decision and all generally refer to the meaning given in the *Electric Utilities Act,* Section 1(1)(h), for "customer" ("means a person purchasing electricity for the person's own use").

5. The following parties responded to these questions in varying respects:[2]

- Alberta Electric System Operator
- Alberta Federation of Rural Electrification Associations
- AltaLink Management Ltd.
- ATCO Electric Ltd.
- Capital Power Corporation
- Community Generation Working Group[3]
- Consumers' Coalition of Alberta
- DCG Consortium[4]
- Desiderata Energy Consulting Inc., on behalf of the industrial customer group[5]
- ENMAX Power Corporation
- EPCOR Distribution & Transmission Inc.
- EQUS Rural Electrification Association Ltd.
- FortisAlberta Inc.
- Kalina Distributed Power Limited and Capstone Infrastructure Corporation
- Lionstooth Energy
- Office of the Utilities Consumer Advocate
- Northstone Power Corp.
- SWITCH Power Corporation
- Tourmaline Oil Corp.
- TransAlta Corporation
- URICA Asset Optimization

6. In reaching the determinations set out within this decision, the Commission has considered all relevant materials comprising the record of this proceeding. Accordingly, references in this decision to specific parts of the record are intended to assist the reader in understanding the Commission's reasoning relating to a particular matter and should not be taken as an indication that the Commission did not consider all relevant portions of the record with respect to a particular matter.

2.1 The DCG credit mechanism

7. It is helpful to begin with an explanation of the distribution-connected generation credit mechanism. DCG is a form of a distributed energy resource, specifically a supply-side distributed energy resource.[6] Since these units are connected to the distribution system, they must

[2] A summary of the proceeding schedule is provided in Appendix 3.
[3] The Community Generation Working Group is comprised of Canadian Renewable Energy Association, the First Nations Power Authority and the Alberta Community and Co-operative Association.
[4] The DCG Consortium members are: Canadian Solar Solutions Inc., Irricana Power Generation, BluEarth Renewables Inc., Elemental Energy Renewables Inc., and RWE Canada Ltd., a subsidiary of RWE AG.
[5] The industrial customer group members are Alberta Direct Connect Consumers Association, Dual Use Customers, Canadian Natural Resources Limited, and the Industrial Power Consumers Association of Alberta.
[6] See Proceeding 24116, Distribution System Inquiry – Final Report, February 19, 2021, PDF page 10, for a further description of distributed energy resources.

be sized to fit to connect to the distribution system and thus are smaller than 80 megawatts (MW), and in most cases much smaller than that.[7]

8. DCG credits are the payments that ATCO Electric, ENMAX and Fortis provide to DCG (both without associated load and as part of self-supply and export configurations) connected to their respective distribution systems.[8] These credits are calculated and paid pursuant to provisions within their respective tariffs: Option M for Fortis, Rate D32 for ATCO Electric, and Rate D600 for ENMAX.

9. The credits are calculated based on the electrical energy delivered by the DCG to the distribution system, and represent the difference between the AESO transmission charges (Rate DTS and Rate STS) the distribution utility must pay with the DCG in operation, and the hypothetical charges that would have been incurred if the DCG had not been in operation. The amounts are calculated manually for each DCG using actual hourly metering data. The calculated credits are then allocated to, and recovered from, all load customers of that distribution utility.

10. EPCOR, the other major electric distribution utility in the province that the Commission regulates, includes a tariff provision related to DCG if the substation[9] to which the generator is connected attracts Rate STS charges from the AESO (referred to in its tariff schedule as Rate SAS-DGEN). This tariff provision is not conventionally considered to be a DCG credit and therefore was not directly at issue in this proceeding. However, this tariff provision is referred to later in Section 3.3.1 of this decision.

11. For clarity, in this decision the term "DCG credits" refers to the Rate DTS credit mechanism, which is the substantial portion of DCG credits (see Table 1 below for more details). The Rate STS credit/charge portion of DCG credits will be referred to and distinguished as required.

2.2 Why this proceeding was held

12. This proceeding is a module of Fortis's 2022 Phase II distribution tariff application considered under Proceeding 25916. Although Fortis's application proposed no changes to its Option M tariff provision, Kalina Distributed Power filed a statement of intent to participate (SIP) requesting the ability to make submissions related to Option M. AltaLink requested that the Commission dismiss Kalina's SIP based on previous Commission rulings[10] that the DCG credits issue was out of scope of both the ATCO Electric and ENMAX Phase II proceedings because of the potential broad-reaching effects to multiple utilities and stakeholders. In those rulings, the Commission determined that regulatory and cost efficiencies would be achieved by hearing the issue within the scope and context of the Distribution System Inquiry (the Inquiry), which was ongoing at the time.

13. Although the issue of DCG credits was explored in depth in the Inquiry, nearly every party suggested that a further detailed review of DCG credits should be undertaken, especially as

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7 Transcript, Volume 1, page 124, lines 4-6.

8 Most micro-generating units, as defined by the *Micro-generation Regulation*, are not eligible for DCG credits.

9 In its tariff, the AESO refers to a substation as a point of delivery (POD).

10 See Proceeding 24116, Exhibit 24116-X0431, Ruling on Canadian Solar Industries Association's request for determination of scope, October 21, 2019. This ruling was also jointly issued in Proceeding 24747 (ATCO Electric 2019 Phase II application) as Exhibit 24747-X0089, and in Proceeding 24820 (ENMAX Power Corporation 2019 distribution tariff Phase II application) as Exhibit 24820-X0037.

the integration of distributed energy resources into the system planning and operation process accelerates.[11] In addition, the Inquiry was purely a fact-finding proceeding, and it was not a proceeding in which distribution tariffs were being adjudicated pursuant to the Commission's ratemaking authority.[12]

14. The issues related to DCG credits have been substantially raised in at least two other regulatory proceedings prior to the Inquiry, neither of which were amenable to making determinations on DCG credit-related matters.[13]

15. Considering the above, the Commission held that it would determine whether DCG credits should continue to be included in a distribution utility's tariff.[14] For the purposes of regulatory efficiency, the Commission bifurcated Proceeding 25916 to address DCG credit-related matters in a separate, concurrent process, and created the present Proceeding 26090. Notice of this proceeding was issued on November 17, 2020.[15]

16. Considering the robust record generated on the DCG credit issue through the course of the Inquiry, the Commission asked parties to compile their evidentiary submissions related to DCG credits filed in the Inquiry, update them as necessary, and file them on the record of the present proceeding. Parties that did not participate in the Inquiry were permitted to file new evidence.[16] The process for this proceeding also included rebuttal evidence, supplemental rebuttal evidence, and oral argument and reply argument.[17] The record for the proceeding closed on March 10, 2021.

3 Does the DCG credit mechanism result in just and reasonable rates?

17. The DCG credit mechanism is a distribution tariff matter and has previously been approved as part of ATCO Electric, ENMAX and Fortis's respective rate schedules.[18]

18. Sections 121(2)(a) and (b) of the *Electric Utilities Act* require the Commission to consider, when approving a tariff application, whether the tariff is just and reasonable; whether the tariff is not unduly preferential, arbitrarily or unjustly discriminatory; or is inconsistent with, or in contravention of, the *Electric Utilities Act* or any other law. For the reasons that follow, the Commission finds that the provision of the DCG credit mechanism does not support just and reasonable ratemaking because it unnecessarily increases the payments ratepayers make for transmission service, and these additional payments are not offset by a proven quantifiable benefit to the ratepayers. Furthermore, the provision of the DCG credit mechanism is not just and

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11 Proceeding 24116, Distribution System Inquiry final report, paragraph 445.
12 Proceeding 24116, Distribution System Inquiry final report, paragraph 15.
13 See Proceeding 22534, Final report for the Alberta Electric Distribution System-Connected Generation Inquiry, December 29, 2017; and Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019.
14 Exhibit 26090-X0005, AUC letter – DCG credits and initial process schedule, paragraph 9.
15 Exhibit 26090-X0008, Notice.
16 Exhibit 26090-X0005, AUC letter – DCG credits and initial process schedule.
17 Exhibits 26090-X0099 and 26090-X0104, AUC letters amending the issues list and process schedule.
18 *Electric Utilities Act*, Section 1(1)(zz): " 'tariff' means a document that sets out (i) rates, and (ii) terms and conditions."

reasonable because it promotes an unlevel playing field between generators, resulting in distortionary harm to the wholesale electricity market, which is also a detriment to ratepayers.

19. The Commission provides its rationale for whether DCG credits are just and reasonable in the remainder of Section 3. These reasons are stated in terms of what DCG credits cost ratepayers; what benefit, if any, ratepayers receive for these payments; and whether DCG credits are consistent with Alberta's market design.

20. There is no applicant in this proceeding. Rather, the Commission determined that the issue of whether DCG credits should be maintained in Fortis's distribution tariff should be considered in a separate module of Fortis's Phase II application, and the scope of the proceeding was extended to include the distribution tariffs of ATCO Electric and ENMAX. In this proceeding, the Commission sought factual information and submissions on whether DCG credits should be maintained in the distribution tariff of a utility. The Commission's decision, therefore, will not turn on whether any particular party met the required onus or not, but rather whether the Commission is satisfied on all the evidence and argument that DCG credits should be maintained in the distribution tariffs of ATCO Electric, ENMAX and Fortis.

3.1 What DCG credits cost ratepayers

21. The first issue the Commission must consider is what DCG credits cost ratepayers.

22. Credits given to DCG are recovered from the respective distribution utilities' load customers as part of the utility's approved distribution tariff. The distribution tariff sets the rates to recover the cost for transmission and distribution service. From the distribution utilities' point of view, the cost of transmission service is determined by the AESO and recovered via the AESO tariff on an individual substation basis, as approved by the Commission. The distribution utility flows the cost of transmission charges through to its load customers through transmission access charges.[19] DCG credits relate to transmission access charges.

23. If DCG is able to locate on a distribution feeder that also serves load and is able to generate electricity coincident with that load, its operation reduces the flow of energy from the transmission system to the substation. Given the current AESO tariff design and metering locations, these reduced flows serve to lower the transmission billing determinants of metered demand and energy at the substation. Since a considerable portion of the AESO's tariff is collected from its bulk and regional charges on the basis of the monthly coincident peak of the system (12 CP), the reduction in metered demand coincident to the peak can significantly reduce the bill received by the distribution utility from the AESO for transmission service due to the presence of DCG on the feeder.

24. In order to continue to recover the total costs of the transmission system, the AESO employs true-up mechanisms that result in the reduced distribution utility payments being recovered, in subsequent periods, from all ratepayers. As a consequence, ratepayers pay for DCG credits in addition to paying for the full cost of the transmission system.

25. Table 1 shows the amounts ATCO, ENMAX and Fortis paid to DCG over an eight-year period, which in turn was collected from their load customers in the form of transmission access charges under their respective distribution tariff. Section 3.2.1 discusses the mechanisms that

[19] Also referred to as system access service (SAS) charges.

result in load customers paying for DCG credits. In each of 2018 and 2019, approximately $28 million in credits was paid to DCG based on the AESO Rate DTS portion of the DCG credit mechanism.

Table 1. Payments of DCG credits by ATCO, ENMAX and Fortis[20]

	Number of DCG units [# of generators]	Growth rate of DCG units [(current - previous) /previous]*100	Total DCG energy [MWh]	Growth rate of energy provided [(current - previous) /previous]*100	Sum of DCG credits		Growth rate of DCG credits paid [(current - previous) /previous]*100
					Based on reduced Rate DTS [$ million]	Based on Rate STS flow-through [$ million]	
	[A]	[B]	[C]	[D]	[E]	[F]	[G]
2012	53		390,677		5.2	0.00	
2013	51	-4%	473,404	21%	8.8	0.00	69%
2014	58	14%	343,786	-27%	5.3	-0.01	-40%
2015	67	16%	562,654	64%	10.9	-0.01	106%
2016	73	9%	747,576	33%	15.8	0.00	45%
2017	75	3%	720,486	-4%	23.0	0.16	47%
2018	77	3%	902,552	25%	28.2	0.38	23%
2019 (Jan-Oct)	79	3%	909,973	1%	28.2	0.43	0%
Simple average		6%		16%			36%

26. Parties disputed the significance of these payments, not the quantum. DCG proponents suggested that the quantum is small compared to the AESO's annual revenue requirement (approximately 1.3 per cent in 2018).[21] Fortis noted that in 2020 it paid out $24.6 million to DCG, which resulted in a 3.6 per cent increase in transmission access charges to the rest of its customers.[22]

27. The Commission notes that the trend in the number of DCG units (column [A] in Table 1), compared to the amount of energy they produce (column [C]) and the value of the credits paid (column [E]) is of equal relevance to the absolute quantum. Table 1 shows that, since 2012, almost every year has seen a moderate growth in the number of DCG units (annual average growth of six per cent), while the volumes of energy produced by these units (annual average growth of 16 per cent) and the credits paid out to generators (annual average growth of 36 per cent) have grown at a much larger pace. This suggests to the Commission that (i) dynamic energy flows on distribution systems are increasing; (ii) business entities are increasingly incented (for a variety of reasons) to install DCG; and (iii) this represents a growing liability for ratepayers.

28. Regarding the question of the quantum of dollars paid through the DCG credit mechanism, the cumulative amount must also be considered. Summing all of the Rate DTS DCG

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20 Exhibit 26090-X0077, FAI-AUC-2019NOV29-009; Exhibit 26090-X0097, EPC-AUC-2019NOV29-009; Exhibit 26090-X0098, ATCO-AUC-2019NOV29-009.

21 See, for example, Transcript, Volume 1, page 42, lines 16-23, and page 70, lines 7-10.

22 Exhibit 26090-X0069, Fortis primary evidence, paragraph 7.

credits and payments from 2012 to 2019 shows that a total of $125 million has been recovered from load customers.

29. In summary, DCG credits represent a notable and escalating cost to ratepayers.

30. In addition to the tangible costs in terms of actual dollars recovered from load and paid to DCG, DCG credits create a hidden cost to ratepayers by weakening the economic efficiency of the wholesale electricity market. These costs are more difficult to quantify, but are real costs, and will be discussed in more detail in Section 3.3.1 regarding the level playing field considerations for generation.

31. In the Commission's view, the fact that DCG credits result in a cost to ratepayers does not in itself make DCG credits unjust or unreasonable. The question of whether ratepayers, or society more generally, benefit from these charges must also be considered.

3.2 What benefits DCG credits provide ratepayers

32. Parties advanced several arguments for maintaining DCG credits, summarized below:

(1) By locating closer to load, DCG offloads the transmission system, resulting in congestion relief, reduced line losses, and potentially deferring or eliminating future builds, thus leading to ratepayer costs savings. DCG credits create an effective locational price signal for DCG and compensate DCG for these locational-based services and cost savings to ratepayers.[23]

(2) There is an unlevel playing field between DCG and TCG arising from:

(i) The *Transmission Regulation*, which constitutes an unfair subsidy to TCG because it requires an uncongested transmission system. Since the regulation does not constrain where TCG can locate, this causes more transmission assets to be built at the expense of load customers.[24]

(ii) Constrained access and/or reduced reliability for DCG by being located on distribution systems.

(iii) DCG paying operating and maintenance fees to distribution utilities.

(iv) DCG having limited access to additional revenue streams; for example, ancillary services, which may not be available to DCG due to their relative size.

This unlevel playing field benefits ratepayers. DCG credits compensate DCG for this unlevel playing field.[25]

(3) DCG credits are directly analogous to the savings created by industrial system designations (ISDs) connected to the distribution system, as well as savings from

[23] Exhibit 26090-X0051, DCG Consortium evidence, Section 4.1; Exhibit 26090-X0054, Northstone Power evidence, PDF pages 1-2; Exhibit 26090-X0066, Lionstooth evidence, PDF pages 2-3; Exhibit 26090-X0125, URICA rebuttal, PDF pages 8-11.

[24] Exhibit 26090-X0127, Kalina rebuttal evidence, paragraph 8.

[25] Exhibit 26090-X0065, URICA evidence, PDF page 5; Exhibit 26090-X0066, Lionstooth evidence, PDF page 3; Exhibit 26090-X0127, Kalina rebuttal evidence, paragraph 49.

such measures as energy efficiency and demand response technologies. All of these connection and/or technology configurations are installed in order to respond to the price signal set by the AESO tariff (i.e., bulk and regional 12 CP tariff) and are also electrically equivalent. Eliminating DCG credits would create an unlevel playing field with respect to these other connection and/or technology configurations.[26]

(4) Removal of DCG credits would upset the economics of existing DCG. Investors may have installed DCG, rather than TCG, due to the existence of DCG credits.[27]

33. The Commission addresses these arguments in the remainder of the decision.

3.2.1 Does DCG reduce or increase transmission costs

34. Parties representing DCGs maintained that DCG installations reduce transmission costs and provide benefits to ratepayers. In their view, DCG should be compensated for the savings and benefits they provide, and DCG credits offer a simple and effective means to flow through Rate DTS cost savings and act as a proxy to recognize the positive impact that DCG has on the transmission and distribution systems.

35. For example, Kalina and Lionstooth claimed that being connected to the distribution system provides the following benefits that accrue to ratepayers:

(1) A lower bill to the distribution utilities from the AESO.

(2) Savings through reduced revenue requirements for TFOs, since by accepting distribution system constraints, and not connecting to an unconstrained transmission system, DCG defers or avoids the requirement for upgrades to the transmission system.

(3) There are reduced flows on the transmission system because by locating generation closer to load, line losses are reduced.[28]

36. The Commission first addresses whether DCG provide savings to ratepayers through avoided or deferred transmission wires costs, then addresses DCG credits' affect on transmission access charges for ratepayers.

Avoided or deferred transmission wires costs

37. The Commission finds insufficient evidence to support the view that DCG reduces transmission costs in the long term in the current regulatory environment, since DCG credits do not account for whether transmission wires costs are actually deferred or avoided in respect of where the DCG is located. Further, the AESO does not currently take the presence of DCG into account in its system planning.[29]

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[26] Exhibit 26090-X0051, Power Advisory evidence for DCG Consortium, paragraphs 62-68, PDF pages 15-17; Exhibit 26090-X0089, Kalina evidence, paragraphs 23-25.

[27] Exhibit 26090-X0054, Northstone evidence; Exhibit 26090-X0060, Tourmaline evidence.

[28] Transcript, Volume 1, pages 66-69 and 83-86; Exhibit 26090-X0107, Appendix: Savings Flow-Through Impact Calculation Assessment.

[29] Exhibit 26090-X0084, AESO evidence, paragraph 30.

38. Kalina submitted evidence[30] [31] to show that DCGs reduce transmission system usage and create transmission system capacity and that, with improvements in integrated planning, can result in significant savings.[32] Citing the Nican reports and responses, Kalina maintained its position that DCG reduces the use of the transmission system, frees up system capacity and subsequently defers the need for transmission upgrades.[33]

39. In AltaLink's view, the Nican studies that analyzed specific planning areas did not provide useful results. It explained that "the ability for generation to relieve or cause stress on transmission elements is primarily a function of the relative balance between load and generation over broader areas and has little to do with the balance between load and generation at individual substations."[34] Accordingly, planning studies performed by the AESO that include non-wires alternatives to address specific transmission issues would provide more meaningful results.[35] AltaLink explained this point in terms of the example used by the Nican studies:

> In this simple case, the 1 MW addition saves 1 MW of capacity in the path between Lake Louise and West Cascade. The only value of freed up transmission capacity is to supply load. In this case, this would allow an additional 1 MW of load to be added at Lake Louise. However, this "savings of transmission capacity" (regardless of how it is viewed) is meaningless from a capacity perspective as all of the elements on the transmission path from Cascade to Lake Louise already have enough capacity for the foreseeable future load in this area. In short, Nican is solving a problem that does not exist.[36]

40. Most parties generally agreed that DCG credits in their current form do not provide an effective locational price signal for where DCG would provide the most benefits to the system.[37] However, DCG proponents highlighted the benefit of locating generation closer to load, which could offload the transmission system, relieve congestion and reduce line losses, in turn deferring or eliminating future builds, resulting in savings to customers.

41. In its evidence for the DCG Consortium, Power Advisory noted that several jurisdictions are attempting to quantify the value of DCG and other distributed energy resources within tariffs. It proposed an alternative methodology that, in its view, would maximize transmission and distribution system cost deferrals and reductions. By way of an example, Power Advisory

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30 Exhibit 26090-X0091, Nican report originally submitted in Proceeding 24116, PDF page 2.
31 Nican, on behalf of Kalina, performed a power systems analysis, which evaluated the impact of adding DCG in two geographically areas: Peace River and Fort Saskatchewan. It concluded, in summary, that for each DCG MW injection, there is a reduction in transmission capacity utilization in the following proportions: 6.9 MW (Bulk), 2.9 MW (Local or Regional) and 1.7 MW (substation). In response to AltaLink's observation that the majority of DCGs are not being sited in Peace River and Fort Saskatchewan, Nican expanded its analysis to include nine planning areas in each of the Central and South Planning regions. See Exhibit 26090-X0092, Nican response to AltaLink comments, PDF page 5.
32 Exhibit 26090-X0127, Kalina rebuttal evidence, paragraph 53, PDF pages 24-25.
33 Exhibit 26090-X0128, Kalina rebuttal evidence, Appendix A, PDF page 8.
34 Exhibit 26090-X0115, AltaLink rebuttal evidence, paragraph 40, PDF page 12.
35 Exhibit 26090-X0115, AltaLink rebuttal evidence, paragraphs 40-49, PDF pages 12-14.
36 Exhibit 26090-X0115, AltaLink rebuttal evidence, paragraph 47, PDF page 13.
37 See for example: Exhibit 26090-X0049, ATCO evidence, PDF page 8; Exhibit 26090-X0051, DCG Consortium evidence, paragraph 33; Exhibit 26090-X0053, TransAlta evidence, PDF page 2; Exhibit 26090-X0054, Northstone evidence, PDF page 2, response (b); Exhibit 26090-X0056, ENMAX evidence, PDF page 3; Exhibit 26090-X0058, CCA evidence, paragraph 16; Exhibit 26090-X0061, EDTI evidence, paragraph 14; Exhibit 26090-X0069, Fortis evidence, paragraph 10; Exhibit 26090-X0083, AltaLink evidence, paragraphs 60-62; Exhibit 26090-X0084, AESO evidence, paragraphs 35-41.

described the policy implemented by the New York Public Service Commission, which includes providing a credit to recognize the value of the DER based on avoided distribution system costs and a credit based on location.[38]

42. Several parties indicated that non-wires solutions,[39] including DCG, should be considered in planning studies performed by the AESO and distribution utilities.[40] Parties acknowledged that such studies could eventually result in the deferral of transmission costs by employing non-wires solutions to address specific transmission issues at specific locations. In Decision 23943-D01-2020,[41] the Commission encouraged the AESO and the distribution utilities to find alternative solutions, rather than consistently relying on new or upgraded transmission facilities to solve an electrical system issue. The Commission's view on this matter has not changed. However, the fact remains that currently, as the AESO explained, historical costs are embedded in the overall transmission system and these costs are collected via Rate DTS and the annual deferral account reconciliation process. Absent a locational price signal and, given the current capacity and design considerations of the transmission system, the Commission finds that the deferral of transmission costs, if any, cannot be attributed to DCG.

43. The Commission acknowledges the potential for DCG to reduce transmission costs by providing electricity or system support services or by more accurately sizing an installation in the proper location. However, given that the AESO does not currently consider the presence of DCG in the planning and operation of the transmission system, the Commission finds that there is insufficient evidence to substantiate these purported benefits of DCG. Further, for the same reasons, programs available in other jurisdictions that provide a credit to recognize the value of distributed energy resources based on avoided costs and the value of distributed energy resources' locations cannot be considered in Alberta unless and until mechanisms are put in place to quantify and assign such costs and savings to generators.[42]

The effect of DCG credits' on transmission access charges

44. Given the Commission's finding that DCG does not reduce transmission costs in the current regulatory environment, the Commission subsequently finds that the current credit mechanism serves to actually increase the payments ratepayers make for transmission service, as any "avoided" Rate DTS charges are still paid by customers of the utility that offers the DCG credit; further, these amounts (which from the AESO's perspective represent uncollected

[38] Exhibit 26090-X0051, Power Advisory evidence for DCG Consortium, paragraphs 62-68, PDF pages 15-17.
[39] Non-wires solutions, also referred to as non-wires alternatives (NWAs) are defined as grid investments or projects that use non-traditional transmission and distribution solutions, including but not limited to: DCG, energy storage, energy efficiency and demand response. The purpose of NWAs is to defer or replace the need for specific infrastructure upgrades (e.g., upgrading a transformer). See Proceeding 24116, Distribution System Inquiry final report, PDF page 55, footnote 106.
[40] See, for example, Exhibit 26090-X0065, URICA evidence, PDF page 6; Exhibit 26090-X0066, Lionstooth evidence, PDF page 22.
[41] Decision 23943-D01-2020: Alberta Electric System Operator, Needs Identification Document Application, Application 23943-A001; EPCOR Distribution & Transmission Inc., Facility Applications, Applications 23943-A001 to 23943-A006; West Edmonton Transmission Upgrade Project, Proceeding 23943, March 12, 2020, paragraph 155.
[42] Such mechanisms would likely require government policy direction, as well as amendments to the regulatory framework.

revenues) are deferred to the AESO's quarterly and annual true-up mechanisms. Thus, ratepayers in aggregate effectively pay twice for a portion of the transmission access charges.

45. The way the DCG credit mechanism is currently structured actually leads to higher overall transmission access payments (in the form of higher Rate DTS and payments arising from the annual deferral account reconciliation process) for all load customers. This happens in two respects, which are explained in the next several paragraphs.

46. The first way transmission access charges increase as a result of DCG credits is because of the legislative requirement that the AESO manage itself "so that, on an annual basis, no profit or loss results from its operation."[43] To meet this obligation, the AESO's tariff includes true-up mechanisms[44] to recover or refund differences between revenues and costs incurred in providing system access service to market participants. While the Commission acknowledges that the presence of DCG on a distribution feeder may reduce the flow of energy from the transmission system on that feeder, and subsequently results in lower Rate DTS charges to the DFO, these savings are only temporary. The AESO's true-up mechanisms ensure that any deficiencies in collecting the required revenue for Rate DTS for any particular distribution utility or substation (including any revenue shortfall resulting from the presence of DCG) are socialized across all load customers of the AESO and are recovered eventually. Therefore, all load customers in aggregate pay for both the total cost of the transmission system and the cost of the DCG credits. From the ratepayers' point of view, this means they are in aggregate effectively paying twice for a portion of the transmission access charges.

47. The second way transmission access charges increase as a result of DCG credits is because the true-up mechanisms themselves and the AESO's revisions to its billing determinant forecast serve to increase the amount of DCG credits paid to DCG over time. The true-up mechanisms increase the transmission access charges for all customers, as explained in the previous paragraph, which subsequently increases the amount of transmission access charges distribution utilities can temporarily avoid through the presence of DCG, but are still charged to its load customers. This shortfall in revenue caused by lower billing determinants is accounted for in the AESO's subsequent forecasts, resulting in higher per unit Rate DTS charges, thus increasing the amount paid to DCG credits for the same amount of energy provided to the system.

48. The transient nature of Rate DTS savings and the two ways DCG credits increase transmission charges was illustrated by a simplified example provided by the AESO and summarized in Appendix 2 to this decision.[45] In brief, the mechanism results in distribution utility customers paying more for transmission charges over time than they would have paid without DCG credits.

49. The AESO further explained that Rate DTS rates reflect historical sunk costs, and that while DCG may reduce charges at a given substation, DCG does not reduce the embedded costs of the overall transmission system.[46] This in turn, necessitates the existence of true-up mechanisms to ensure that the embedded costs of the transmission system are recovered. EPCOR

[43] *Electric Utilities Act*, Section 14(3).
[44] These mechanisms are established by way of a deferral account adjustment rider (Rider C and deferral account reconciliation settlements).
[45] Exhibit 26090-X0084, AESO evidence, paragraphs 5-25.
[46] Exhibit 26090-X0122, AESO rebuttal evidence, paragraphs 5-7, PDF page 4.

noted that analysis provided by DCG proponents in this proceeding did not include the true-up of costs and cost recovery from ratepayers that the AESO undertakes through its quarterly Rider C mechanism or through its annual deferral account reconciliation process.[47]

50. While some DCG proponents acknowledged the AESO true-up process, in their view, the process is not relevant to them.[48] Kalina explained that DCG did not cause the overbuild sunk cost problem, nor can it reduce current sunk costs, and therefore DCG should not be responsible for an overbuilt system and "erroneous" load forecasting by eliminating the DCG credit.[49] In Kalina's view, the situation could be improved if the AESO forecast more accurately and revised its expectation to receive payments from distribution utilities that have DCG. The Commission finds that this argument fails to take into account (i) the AESO's statutory obligation to true up its revenues and costs; (ii) the DCG credits that Kalina supports are predicated on the forecasting problem Kalina criticizes (i.e., DCG credits are calculated based on a comparison of actual transmission access charges to charges that would have been in the absence of DCG); and (iii) DCG do not have a statutory obligation to serve load, whereas the AESO does – if DCG does not serve the load at some point, for whatever reason, when it had previously done so and the AESO had altered its forecast as a result, it is the AESO that would be accountable, not the DCG.

51. In light of the foregoing, the Commission finds that no ratepayer pays a lower bill for avoided transmission access charges due to DCG, in the short or long term. This is because the costs of the transmission system are largely sunk, and the presence of DCG credits is later reconciled in the annual true-up process, which only serves to inflate the DCG credit payments, further exacerbating the problem. This finding is consistent with the Commission's observations in Decision 22942-D02-2019[50] and the AUC's Final Report for the 2017 Alberta Electric Distribution System-Connected Generation Inquiry.[51]

52. In comparing the proven costs of DCG credits to ratepayers (as shown in Section 3.1) in relation to the Commission's finding that there are no benefits to ratepayers (as was just shown in Section 3.2), the Commission finds that inclusion of DCG credits in distribution utilities' tariffs is not just and reasonable on this basis. The Commission further considers DCG credits in contributing to, or detracting from, setting a level playing field among competitors.

3.3 Level playing field considerations

53. The third issue the Commission asked for submissions from parties on was level playing field considerations related to retaining DCG credits.

54. Advocates of the purported benefits of DCG claimed that the credits are needed to set a level playing field between DCG and various other connection and/or technology configurations, such as TCG, energy efficiency, demand response and onsite generation (i.e., dual use customers).

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47 Exhibit 26090-X0117, EPCOR rebuttal evidence, paragraphs 5-7, PDF page 5.
48 Exhibit 26090-X0086, Community Generation Working Group evidence, PDF pages 4-5.
49 Transcript, Volume 1, page 70.
50 Decision 22942-D02-2019: Alberta Electric System Operator, 2018 ISO Tariff Application, Proceeding 22942, September 22, 2019, paragraph 787.
51 Proceeding 22534, Alberta Electric Distribution System-Connected Generation Inquiry, Final Report, December 29, 2017, paragraph 277.

55. The Commission finds that DCG credits are not needed to level any playing field; rather, DCG credits create an unlevel playing field, which distorts the wholesale electricity market and harms ratepayers as a result. DCG credits are not just and reasonable on this basis. This finding is elaborated upon in the remainder of Section 3.

3.3.1 Level playing field considerations for generation

56. Several of the stated purposes of the *Electric Utilities Act*, include (i) providing for a fair, efficient and openly competitive electricity market for generation;[52] and (ii) maintaining a flexible framework so that decisions on the need for and investment in generation of electricity are guided by competitive market forces.[53] DCG credits are antithetical to these objectives for the following reasons.

57. First, DCG credits are not available to all forms of generation, including all forms of distributed generation.[54] Alberta's wholesale electricity market is premised on generation competing on a level playing field to ensure lowest cost outcomes. Providing certain DCG with a revenue stream through the distribution tariff that is separate from the wholesale market, is not available to all forms of generation (i.e., only to DCG and not TCG), and is not available on all distribution systems (i.e., not EPCOR's), distorts the level playing field and interferes with achieving efficient market outcomes. As the AESO explained, this distortion leads to inefficient outcomes in two respects: (i) the energy market is impacted by the DCG's operations to maximize generation output at times when the DCG will maximize its credit value, potentially displacing otherwise lower cost generation; and (ii) the market is impacted through the distortion DCG credit revenue sends to the investment signal for DCG, affecting the market's ability to truly find the efficient generation mix aligned with long-run equilibrium.[55] These distortions in market efficiency are the hidden costs of DCG credits referred to in Section 3.1.

58. Second, although DCG proponents claimed benefits of siting generation closer to load, connecting generation to the distribution system, rather than to the transmission system, cannot be expected to generally produce transmission system benefits beyond potentially reducing local transformation needs. For example, locating additional DCG in an area that already has surplus generation would increase transmission outflows independent of whether it was connected to the transmission or distribution system. Likewise, to the extent that transmission system benefits do result from advantageously locating generation, TCG could be expected to provide the same or similar benefits as DCG. For example, if TCG was located in an area with more load than generation, it could also reduce inflows and line losses.

59. DCG credits are unaffected by location on the transmission system and so cannot provide locational signals that reflect transmission benefits or disbenefits. Further, if these locational benefits were priced to encourage their provision, a level playing field would require that the compensation (i.e., credits) should be available to most, if not all, generating units capable of providing those benefits.

52 *Electric Utilities Act*, Section 5(b)-(c).
53 *Electric Utilities Act*, Section 5(d).
54 For example, EPCOR does not have a similar DCG credit in its tariff.
55 Exhibit 26090-X0084, AESO evidence, paragraph 38. The AESO referred to the first inefficient outcome as weakening the static efficiency of the market and the second inefficient outcome as weakening the dynamic efficiency of the market.

60. Section 47(b) of the *Transmission Regulation* sets out the locational-based price signals for generating units that the Commission must consider in the AESO's tariff application. These include local interconnection costs, a financial contribution toward transmission system upgrades (also known as generating unit owner's contribution), and line losses levied through Rate STS of the AESO tariff. These locational price signals are applied to all generating units which connect to the transmission system across the province.

61. In contrast, DCG receives a connection to the transmission system through the distribution utility's electric distribution system.[56] The distribution utility is the entity that contracts for system access service with the AESO and is subject to costs of the transmission system, as well as charges or credits under Rate STS. In order to support a level playing field between TCG and DCG, the Commission considers that Rate STS and the other locational-based price signals identified in Section 47(b) of the *Transmission Regulation* should be flowed through to DCG, if the electricity generated by the DCG enters the transmission system at the distribution utility's point of delivery (i.e., substation).

62. EPCOR distinguished between DTS-based DCG credits and STS-based DCG credits. EPCOR's approved tariff flows through the STS charges or credits to DCG,[57] but does not credit DCG for any temporary reductions in DTS charges. In view of the level playing field considerations discussed above, the Commission finds that there is merit in retaining the respective utility tariff provisions that are related to the flow through of STS charges or credits to DCG. This finding is consistent with the fact that DTS charges are the price intended for load customers in connecting to, and receiving service from, the transmission system, whereas STS charges or credits are the price intended for generating units, whether they be TCG or DCG.

63. Kalina drew a comparison between the compensation that DCG credits provide to DCG and the AESO's tariff provision of transmission-must run (TMR), which compensates TCG for generating electricity out of merit to relieve transmission capacity constraints in a particular location.[58] In the Commission's view, this comparison is inaccurate for two reasons.

64. First, the AESO enters into contracts with generating units to provide services under TMR. TMR is used by the AESO only under certain conditions determined by the AESO to merit such an approach. The AESO, as the transmission planner, is able to plan for and manage the grid accordingly, using TMR only as necessary. Because the AESO has no influence where DCG locate or how they operate, the AESO does not take them into account when it plans the transmission system.

65. Second, these contracts competitively procure a set amount of generation capacity for targeted locations as determined by the AESO based on need. This is different from DCG

56 For example, see Decision 25848-D01-2020: Alberta Electric System Operator, Stage 2 Review and Variance of Decision 22942-D02-2019 Adjusted Metering Practice and Substation Fraction Methodology Proceeding 25848, December 23, 2020; and Decision 26215-D01-2021: Alberta Electric System Operator, Compliance with Decision 25848-D01-2020, Proceeding 26215, April 29, 2021.

57 Rate STS applies where energy is deemed to have entered onto the transmission system, as measured by a metering point. This applies to TCG or a distribution utility if a DCG's energy flows onto the transmission system from the distribution utility's service territory. The rate is a charge (credit) for the calculated line losses the transmission incurs (avoids) as a result of the generating unit.

58 Exhibit 26090-X0090, Kalina evidence, Appendix A, PDF page 6; Exhibit 26090-X0127, Kalina rebuttal evidence, paragraph 55.

credits, which are not managed by the AESO and are provided indiscriminately relative to the need of the transmission system for any given location.

66. In view of the above, the Commission finds that DCG credits impair the competitive generation market intended by the *Electric Utilities Act* to the detriment of consumers, and are also not just and reasonable on this basis. Despite this, the Commission considers two additional specific arguments related to level playing consideration in sections 3.3.2 and 3.3.3 below.

3.3.2 Level playing field considerations for DCG compared to ISDs, energy efficiency or demand response technologies

67. Several parties argued that DCG "create a similar value proposition"[59] to the Alberta Interconnected Electric System (AIES) as ISDs, as do the installation of energy efficiency or demand response technologies.[60] They reasoned that because DCG provide comparable value to the AIES as these other connection and/or technology configurations in terms of reducing energy flows at the substation, DCG credits provide the financial compensation for this value and put all of these connection and/or technology configurations on equal footing.[61]

68. These parties pointed to the Alberta Energy and Utilities Board's (the Commission's predecessor) Decision 2000-01 in support of their argument. That decision, combined with Decision 2000-25,[62] created the DCG credit mechanism.

69. Decision 2000-1 approved ESBI Alberta Ltd.'s (the AESO's predecessor) request to adjust its metering practice from gross to net metering at the substation, principally to support the public policy objective of incenting flare-gas generation to reduce flaring.[63] ESBI, supported by the Independent Power Producers Society of Alberta (IPPSA), submitted that moving to a net metering approach at the substation matched the physical reality of the system. IPPSA further argued, and the Board accepted, "that the current tariff treatment provides an unfair competitive advantage for industrial system cogeneration operators over distribution attached generators."[64] IPPSA contended that under the practice of gross metering, DCG was added back to metered substation energy transfers for determining billing determinants, thus a distribution utility would not earn the same savings that an industrial system would earn from installation of a beyond-the-substation generator, even though the impact on the transmission system was the same.

70. Despite the Commission's predecessor making a finding that there was an unfair competitive advantage between DCG and ISDs previously, the Commission does not accept this

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59 See for example Exhibit 26090-X0089, Kalina and Capstone evidence, paragraph 38(d).
60 Installing energy efficiency and/or demand response technologies are sometimes referred to as peak shaving, as the technologies serve to reduce the consumer's peak demand.
61 Exhibit 26090-X0051, DCG Consortium evidence, paragraph 17.
62 Decision 2000-25: ESBI Alberta Ltd., 1999/2000 Tariff Application Refiling – Part B, Tariff and Terms and Conditions, Application 990005, File 1803-5, April 25, 2000.
63 Desiderata provided evidence stating that the DCG credit mechanism was "not overly successful in promoting the development of DCG using otherwise flared gas. While a few otherwise flare gas generation projects were developed, most of the reduction in natural gas being flared was due to higher commodity prices (making solution gas economic to process and sell) and public pressure on oil production companies to stop flaring." See Exhibit 26090-X0057, Desiderata evidence, Q7.
64 Decision 2000-01: ESBI Alberta Ltd., 1999/2000 General Rate Application, Phase 1 and Phase 2, Application 990005, Files 1803-1, 1803-3, February 2, 2000, page 219.

prior finding as justification for the existence of a DCG credit mechanism for the following reasons.

71. First, the circumstances have changed under which the DCG credit mechanism was approved. Notably, in Decision 22942-D02-2019, the Commission approved the AESO's request to return to a gross metering approach at the substation, rather than maintaining a net metering approach.[65]

72. Second, in sections 3.1 and 3.2 of this decision, the Commission has found that DCG credits do not benefit ratepayers commensurate with their cost.

73. Third, and perhaps most importantly, the legislative framework does not support any argument of common energy flows and system impacts. The *Electric Utilities Act* distinguishes between a consumer, DCG and ISD.[66] The *Electric Utilities Act* and *Hydro and Electric Energy Act* set out different rights and obligations for each. In brief, load customers are under no obligation to consume electricity. They may choose to curtail their consumption from the AIES at any point in a manner that serves their own interests, which may be done through the installation of energy efficiency or demand response technologies, including installing onsite generation that solely serves their own needs.[67] ISDs have express legislative rights to install onsite generation that serves their own needs, as well as supplying excess electricity to the grid.[68] In contrast, DCG (referred to as "distributed generation" in the *Electric Utilities Act*) do not serve their own load, but potentially that of other load customers connected to the same distribution feeder or substation.

74. The argument that DCG results in the same effect at the substation in terms of the physical flows of energy as ISDs, energy efficiency or demand response technologies ignores the legislature's decision to afford these connection and/or technology configurations differing treatment under the legislation. Energy efficiency, demand response, onsite generation for own use, and ISDs are all installed, either exclusively or principally, to serve a customer's own energy needs. Stand-alone DCG are not installed to serve onsite load, and therefore are not entitled to the same rights as load customers or ISDs.

3.3.3 Level playing field considerations for dual use customers

75. Desiderata, on behalf of the industrial customer group, identified that the DCG credit mechanism is based on the premise that a DCG can send electricity from its site to other load customers served from the same substation and receive the associated transmission tariff cost savings. Desiderata therefore recommended the Commission consider adjusting the DCG credit mechanism so that the eligibility be limited to on-site load that is being served by an on-site generator (i.e., dual use customers, as they are both load and generation).

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65 Decision 22942-D02-2019, paragraph 645.

66 See, for example, the definitions for "customer," "distributed generation," "generating unit" and "industrial system," *Electric Utilities Act*, Section 1(1). The *Electric Utilities Act* definition of "industrial system" refers to the *Hydro and Electric Energy Act* definition, Section 1(1)(g): " 'industrial system' means the whole or any part of an electric system primarily intended to serve one or more industrial operations of which the system forms a part and designated by the Commission as an industrial system."

67 *Electric Utilities Act*, Section 2(1)(b).

68 *Hydro and Electric Energy Act*, Section 4.

76. Desiderata suggested that transmission-connected dual use customers and distribution-connected dual use customers should be subject to equal treatment, particularly if they cause the same costs on the grid, and that retaining a modified form of DCG credit for dual use customers would provide for more equal treatment between them. Desiderata explained that there are effectively three types of dual use customers that are otherwise similar, but for how transmission costs are billed to them. Specifically, transmission-connected AESO customers and transmission-connected distribution customers (i.e., ATCO Electric's T31, ENMAX's Rate D600, EPCOR's SAS/DC, and Fortis's Rate 65) are billed based on a direct flow through of the AESO's Rate DTS regardless of whether the AESO or a DFO bills the customer. This means behind-the-fence generation for these customers is highly profitable because they are subject to the 12 CP price signal. Desiderata contrasted these connections with a third type of dual use customer that does not have the AESO's Rate DTS flowed through (e.g., Fortis's Rate 63), and therefore is not subject to the same price signal as its otherwise similar contemporaries.[69] Desiderata suggested that by retaining the DCG credit mechanism, and narrowing it to apply to customers that do not receive a straight flow through of the AESO's Rate DTS, would level the playing field between industrial customers of all connection types.

77. The Commission agrees there is merit in suggesting that customers that cause similar costs or benefits on the system should be subject to similar price signals that accurately reflect those costs or benefits. However, the Commission has determined that DCG credits increase consumer costs because they do not produce benefits that are commensurate with their costs. Accordingly, the Commission is unconvinced that achieving consistency between industrial customers of all connection types is sufficient cause to retain some altered form of DCG credits. Instead, the preferred approach would be to universally improve the transmission charges for all customers. That is, ensure that the AESO's tariff is based on cost causation and sets effective price signals, and these rates are charged to all load customers, regardless of the connection, as best as the metering infrastructure will allow.[70] Such an approach to rate design at the transmission and distribution levels is more likely to lead to economically efficient outcomes, compared to adjusting the DCG credit mechanism in isolation.

78. In relation to the issue identified in Section 3.3 of this decision, the Commission finds that the DCG credits create a distortionary harm to the wholesale electricity market, which is not consistent with Alberta's market design, and therefore impairs the competitive purpose of the *Electric Utilities Act*. This occurs in the short-run because generators' bidding may be influenced by receipt of DCG credits and in the long-run because investment choices may be distorted away from potentially less expensive alternatives towards DCG, with the result that the overall cost of generation may be unnecessarily increased. This finding is in addition to the finding in sections 3.1 and 3.2 that DCG credits unnecessarily increases the payments ratepayers make for transmission service, and these additional payments are not offset by a proven quantifiable benefit to the ratepayers. The Commission finds that DCG credits should be discontinued as to hold otherwise would result in a tariff that is neither just nor reasonable.

69 Transcript, Volume 1, pages 51-54.
70 Proceeding 24116, Distribution System Inquiry – Final Report, Section 5.2.2.

4 What should the transition period for DCG credits be?

79. Given the Commission's finding that the Rate DTS portion of the DCG credit mechanisms provided by ATCO Electric's, ENMAX's and Fortis's tariffs should not be approved under Section 121(2) of the *Electric Utilities Act*, the Commission must determine the time period for their phase out.

80. Parties presented a full range of options to the Commission, including an indefinite transition period[71] (i.e., providing for legacy rates[72]) to a transition period of less than a year.[73]

81. The Commission has stated in previous decisions[74] that there is no clear rule when legacy rates should or should not be employed. Instead, the benefits and costs of permitting legacy rates must be weighed and balanced.

82. Approving some form of legacy rates for a long period of time (for example, indefinite, asset life, or 20-year period, as proposed by several parties) would perpetuate ratepayers paying for something that provides them no proven benefit. It would also exacerbate any level playing field issues, creating the situation where a subset of DCG would be receiving payments under the legacy provision, that no other generation would be eligible for.

83. However, several parties argued that permitting legacy rates strengthens investor confidence, which provides a benefit to ratepayers. Alberta's wholesale electricity market relies on investors to make investments to maintain existing and build new generation, and unnecessarily increasing regulatory risk may increase the cost of electricity for consumers due to pricing in that elevated regulatory risk in business and financial decisions.[75]

84. Alternatively, an immediate or a very short transition period would save ratepayers from the direct costs of the DCG credits and improve the function of the wholesale electricity market but may also erode investor confidence.

85. While the direct costs of legacy rates are more readily calculated using the evidence on the record, the benefits of their continuance to support investor confidence are less clear. Consideration of permitting legacy rates should be made from a public interest perspective, and not a private interest perspective.

86. As the AESO pointed out, the legislative framework in Alberta for electricity generation is that investors take on the risk of investment, in exchange for the associated potential profits.[76] Fortis suggested that beyond five years it becomes very challenging to model the economics of

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71 Exhibit 26090-X0056, ENMAX evidence, PDF page 4; Exhibit 26090-X0142, Kalina supplemental rebuttal evidence, paragraph 8; Exhibit 26090-X0147, URICA supplemental rebuttal evidence, PDF pages 3-4.

72 Often referred to as "grandfathering," but in this decision the Commission has chosen not to use the term.

73 Exhibit 26090-X0053, TransAlta evidence, PDF page 3; Exhibit 26090-X0139, CCA supplemental rebuttal evidence, paragraph 3.

74 Decision 2007-086: ATCO Electric Ltd., 2008 Distribution Tariff Phase II, Application 1500878-1, November 8, 2007, page 49; Decision 2011-226: Alberta Electric System Operator, Objections to ISO Rule Section 502.1 Wind Aggregated Generating Facilities Technical Requirements, Proceeding 787, May 31, 2011, paragraphs 132-135; Decision 24257-D01-2019: Evergreen Gas Co-op Ltd., Franchise Agreement with the Town of Drayton Valley, Proceeding 24257, May 2, 2019, paragraph 28.

75 Exhibit 26090-X0177, SWITCH Power summary argument, PDF page 2.

76 Exhibit 26090-X0140, AESO Supplemental rebuttal evidence, paragraph 9.

most generators due to variability in commodity prices, new technologies and other shifts in the legislative and regulatory framework.[77] Desiderata provided anecdotal evidence that financial creditors understand well that DCG credits are based on a tariff approved through regulatory processes, and thus are seldom relied upon to obtain project financing.[78]

87. With these costs, benefits and related considerations in mind, the Commission finds that a four-year transition period for the Rate DTS portion of the DCG credit mechanism, set on a declining basis, balances the relevant competing public interest objectives and is a reasonable approach in the present circumstances.

88. In accordance with this finding, the Commission directs ATCO Electric, ENMAX and Fortis to calculate the Rate DTS portion of the DCG credits in the same way that they otherwise would have, but then apply the multipliers shown in Table 2 to the calculated value before finalizing and issuing the credit. The Rate STS portion of the DCG-related tariff is to be calculated in accordance with the utility's current practice, with no change (i.e., to provide for a flow through of the AESO's Rate STS credits or charges).

Table 2. Multiplier for the calculated DTS portion of the DCG credit

Year	First day when the multiplier will be applied	Multiplier
1	Jan 1, 2022	0.8
2	Jan 1, 2023	0.6
3	Jan 1, 2024	0.4
4	Jan 1, 2025	0.2
5	Jan 1, 2026	0

89. The Commission further directs ATCO Electric, ENMAX and Fortis to file in their 2022 annual performance-based regulation rate adjustment filings, where changes to their respective rate schedules and terms and conditions are approved, changes that clearly indicate to customers the multiplier schedule set out in Table 2 for the DTS-based portion of the DCG credit mechanism, distinguished from the STS-based portion.

5 Order

90. It is hereby ordered that:

(1) ATCO Electric Ltd., ENMAX Power Corporation and FortisAlberta Inc. are to file in their 2022 annual performance-based regulation rate adjustment filings, where changes to their respective rate schedules and terms and conditions are approved, changes that reflect the following:

(i) D32/D600/Option M will flow through Rate STS charges and/or credits billed by the AESO on a 100 per cent basis.

(ii) D32/D600/Option M will calculate the difference between the AESO's Rate DTS charges to the distribution utility with the DCG in operation and

[77] Transcript, Volume 2, pages 246-247.
[78] Transcript, Volume 1, pages 62-63.

the charges that would have been incurred if the DCG had not been in operation, with the amount determined modified by the multipliers shown in Table 2 of this decision.

Dated on June 7, 2021.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Douglas A. Larder, QC
Vice-Chair

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Alberta Direct Connect Consumers Association
Alberta Electric System Operator (AESO) Norton Rose Fulbright Canada LLP
Alberta Federation of Rural Electrification Associations (AFREA) Main Street Law LLP
AltaLink Management Ltd. (AltaLink)
ATCO Electric Ltd. Bennett Jones LLP
Aura Power Renewables Ltd.
BluEarth Renewables Inc.
Canadian Natural Resources Limited
Canadian Solar Solutions Inc.
Capstone Infrastructure Corporation
Community Generation Working Group
Capital Power Corporation Keith Miller Law
Consumers' Coalition of Alberta (CCA) Wachowich & Company LLP
DCG Consortium Blake, Cassels & Graydon LLP
Desiderata Energy Consulting Inc. (Desiderata)

Name of organization (abbreviation) Company name of counsel or representative
Dual Use Customers
Elemental Energy Renewables Inc.
ENMAX Power Corporation
EPCOR Distribution & Transmission Inc. (EPCOR) Borden Ladner Gervais LLP
EQUS Rural Electrification Association Ltd. McLennan Ross Barristers & Solicitors
FortisAlberta Inc. (Fortis or FAI) Osler, Hoskin & Harcourt LLP
Industrial Power Consumers Association of Alberta
Irricana Power Generation
Kalina Distributed Power Regulatory Law Chambers
Lakeland Rural Electrification Association Limited
Lionstooth Energy
Michichi Solar GP Inc.
NAT-1 GP Inc.
Northstone Power Corporation
Office of the Utilities Consumer Advocate (UCA) Brownlee LLP
Siemens Energy Canada Limited

Name of organization (abbreviation) Company name of counsel or representative
SWITCH Power Corporation
Taber Solar 1 Inc. and Taber Solar 2 Inc.
Tourmaline Oil Corp.
TransAlta Corporation
URICA Asset Optimization

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair D.A. Larder, QC, Vice-Chair Commission staff J. Graham (Commission counsel) R. Lucas A. Ayri G. Bourque A. Corsi C. Fuchshuber

Appendix 2 – Summary of the AESO's simplified example showing how DCG credits increase transmission charges

(return to text)

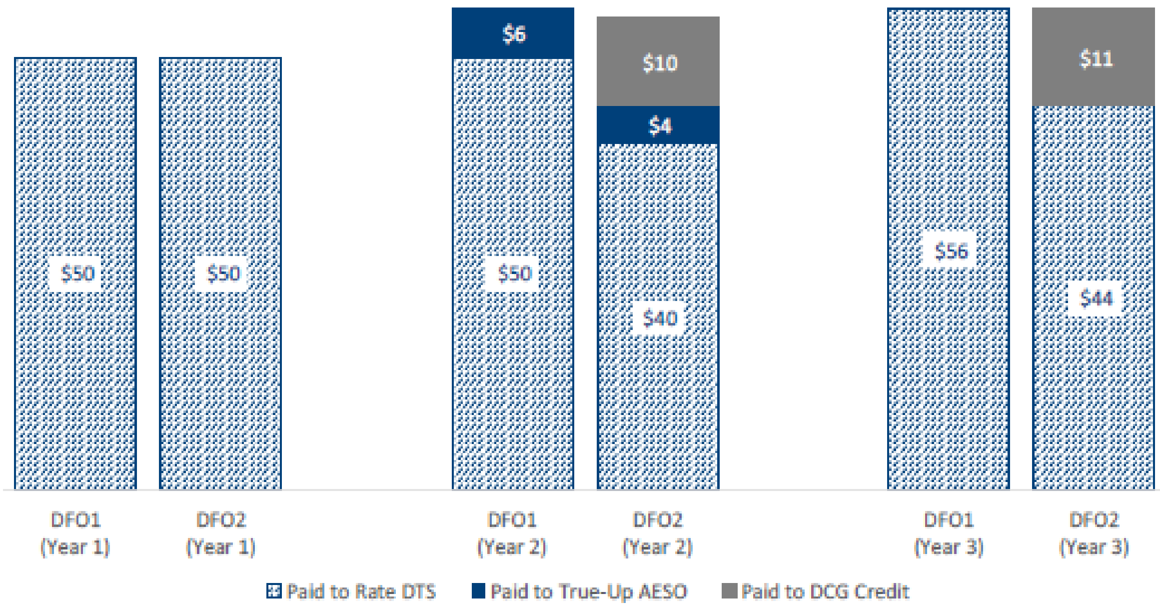
1. This appendix provides a summary of the AESO's simplified example[79] that shows the two ways DCG credits increase transmission charges: the AESO's required true-up mechanisms to collect unrecovered Rate DTS revenue; and the AESO's subsequent revisions to its billing determinant forecast as a result of unrecovered Rate DTS revenue, as described in Section 3.2.1 of this decision.

2. Figure 1 sets a base year (Year 1) where no DCG is present on either distribution utilities' systems (DFO1 and DFO2), and the total transmission access charges of $100 are split equally (five billing units each) and Rate DTS is $10/unit. In Year 2, DCG is added to DFO2's system, which reduces the actual billing determinants for DFO2 by one unit, and drives down Rate DTS revenue collection for the system by one unit. This means DFO2 collects $50 in Rate DTS charges from its customers, $10 of which is paid to DCG, and the AESO collects its shortfall through a true-up mechanism. Thus, in Year 2, DFO1 and DFO2 customers end up paying $56 and $54, respectively, when they would have only had to pay $50 each in the absence of DCG credits – this is the first way DCG credits increase transmission charges.

3. Figure 1 and Table 3 show that in Year 3 of the example, the AESO adjusts its forecasted billing determinants for its Rate DTS calculation to reflect the lower transmission usage for DFO2 from Year 2, which consequently increases Rate DTS for all load customers. This means DCG in Year 3, while producing the same quantity of energy in Year 2 (one unit), are paid a higher amount ($11 instead of $10), and all load customer continue to pay escalating transmission access charges without an expansion of the transmission system, or receiving any additional service. This corresponds to the second way DCG credits increase transmission charges to ratepayers. What is not shown in Figure 1 is how in Year 3 the AESO will continue to collect less than its forecasted revenue from DFO2 (as transpired in Year 2), and a subsequent true-up mechanism will be required, further exacerbating the problem caused by the DCG credits.

[79] Exhibit 26090-X0084, AESO evidence, paragraphs 5-25.

Figure 1. The total costs paid for by DFO1 and DFO2 load customers in the AESO's simplified example



* This simplified example assumes that there are no *in-year* Rider C or DAR amounts. Assume true-ups happen after annual Rate DTS revenue is collected.

Table 3. The AESO's "forecast billing determinants and Rate DTS" for Year 3 of its simplified example

	Year 1	Year 2	Year 3
Revenue requirement ($)	100	100	100
Forecasted billing determinants DFO1	5	5	5
Forecasted billing determinants DFO2	5	5	4
Rate DTS ($/unit)	$10/unit	$10/unit	$11/unit

Appendix 3 – Oral argument and reply argument – registered appearances

Name of organization (abbreviation) **Name of counsel or representative**
Alberta Electric System Operator (AESO) M. Keen
Alberta Federation of Rural Electrification Associations (AFREA) S. Gibbons
AltaLink Management Ltd. K. McGlone
ATCO Electric Ltd. L. Smith, QC
Capital Power Corporation K. Miller
Consumers' Coalition of Alberta (CCA) J. Wachowich, QC
DCG Consortium T.-L. Oleniuk
EPCOR Distribution & Transmission Inc. J. Liteplo
EQUS Rural Electrification Association Ltd. D. Evanchuk
FortisAlberta Inc. M. Ignasiak
Industrial customer group D. Hildebrand
Kalina Distributed Power and Capstone Infrastructure Corporation R. Twyman
Lionstooth Energy G. Lester
Northstone Power Corporation D. St. Pierre
Office of the Utilities Consumer Advocate (UCA) K. Rutherford

Name of organization (abbreviation) **Name of counsel or representative**
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Tourmaline Oil Corp. C. Miiller
URICA Asset Optimization T. Whiteside

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair D.A. Larder, QC, Vice-Chair Commission staff J. Graham (Commission counsel) R. Lucas

Appendix 4 – Summary of proceeding process

The following table summarizes the process steps, rulings and procedural requests addressed during the proceeding:

Date	Process step description
Proceeding 25916	
October 19, 2020	Fortis files its 2022 Phase II distribution tariff application.
October 21, 2020	Kalina files a statement of intent to participate, seeking to provide input on the setting of Fortis's Option M.
November 2-3, 2020	AltaLink and the AESO file letters requesting leave to participate if the Commission determines to retain Option M in scope of the proceeding.
November 17, 2020	The Commission issues notice that it will bifurcate Proceeding 25916 to determine whether DCG credits should continue to be included in a distribution utility's tariff, including Fortis, ATCO Electric and ENMAX. The Commission creates Proceeding 26090 for this purpose, issues scoping questions and sets an initial process schedule.
Proceeding 26090	
November 17, 2020	The Commission opens the proceeding and issues notice.
November 30, 2020	Deadline for statement of intent to participate submissions.
December 3, 2020	The Commission revises the process schedule in response to motions by the AESO and the DCG Consortium to include rebuttal evidence.
December 14, 2020	Deadline for evidentiary submissions.
January 13, 2021	The Commission files excerpts of exhibits from Proceeding 24116 that parties did not refile as evidence.
January 15 & 20, 2021	The Commission amends the issue list to solicit additional information on the issue of permitting legacy rates.
January 27, 2021	Deadline for rebuttal evidence submissions.
January 29, 2021	The Commission responds to a late registration request from NAT-1 GP Inc.
February 3, 2021	Deadline for supplemental rebuttal evidence submissions on permitting legacy rates.
February 17, 2021	The Commission informs parties that it will not be issuing information requests to parties.
March 5, 2021	Deadline to file brief written summary of argument.
March 5, 2021	The CCA seeks leave to file, and filed, "Attachment 1 - CCA submission to the DOE [Department of Energy] on self-supply and export dated February 9, 2021" on the record, which the CCA described as its submission to Alberta Energy regarding self-supply and export.
March 8, 2021	The Commission declines the CCA's motion and removes Attachment 1 from the record of the proceeding.
March 9-11, 2021	Oral argument and reply argument held virtually.
March 17, 2021	Lionstooth files the only undertaking from the oral hearing.

Appendix 5 – Summary of Commission directions

This section is provided for the convenience of readers. In the event of any difference between the directions in this section and those in the main body of the decision, the wording in the main body of the decision shall prevail.

1. In accordance with this finding, the Commission directs ATCO Electric, ENMAX and Fortis to calculate the Rate DTS portion of the DCG credits in the same way that they otherwise would have, but then apply the multipliers shown in Table 2 to the calculated value before finalizing and issuing the credit. The Rate STS portion of the DCG-related tariff is to be calculated in accordance with the utility's current practice, with no change (i.e., to provide for a flow through of the AESO's Rate STS credits or charges). .... paragraph 88
2. The Commission further directs ATCO Electric, ENMAX and Fortis to file in their 2022 annual performance-based regulation rate adjustment filings, where changes to their respective rate schedules and terms and conditions are approved, changes that clearly indicate to customers the multiplier schedule set out in Table 2 for the DTS-based portion of the DCG credit mechanism, distinguished from the STS-based portion..... paragraph 89