Decision **25865-D01-2020**

Alberta Utilities Commission

ENMAX Power Corporation

2021 Annual Performance-Based Regulation Rate Adjustment

December 18, 2020

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1 Decision

1. In this decision, the Alberta Utilities Commission considers ENMAX Power Corporation's (ENMAX or EPC) 2021 annual performance-based regulation (PBR) rate adjustment filing. For the reasons that follow, the Commission has determined that:

- The interim 2021 electric distribution service rates and the corresponding rate schedules, as set out in Appendix 4 to this decision, are approved effective January 1, 2021.

- A distribution access service (DAS) adjustment rider is approved in the amount of $2.47 million effective January 1, 2021, to March 31, 2021.

- Distribution tariff terms and conditions (T&Cs), as set out in Appendix 5 to this decision, are approved effective January 1, 2021, on an interim basis, pending completion of Proceeding 25861[1] and the Commission's finalization of ENMAX's customer terms and conditions therein.

- ENMAX's 2018 going-in rates and 2018 K-bar, calculated in this proceeding, are approved as final.

2 Procedural summary

2. On September 10, 2020, ENMAX submitted its 2021 annual PBR rate adjustment filing to the Commission, requesting approval of its 2021 electric distribution service rates and the corresponding rate schedules, as set out in Appendix 9[2] of its application, to be effective January 1, 2021, on an interim basis. ENMAX also requested approval of its distribution tariff T&Cs of electric distribution service, to be effective January 1, 2021.

3. After issuing a notice of the application on September 11, 2020, the Commission received statements of intent to participate from the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA). The process established for this proceeding included information requests (IRs) to ENMAX, IR responses from ENMAX, written argument and reply argument.

[1] Proceeding 25861: ENMAX Power Corporation, 2019 Distribution Tariff Phase II Application Compliance Filing.
[2] Subsequently updated in Exhibit 25865-X0048.

4. In accordance with the Commission direction in Decision 25422-D01-2020,[3] on November 18, 2020, ENMAX updated its 2021 PBR rate adjustment schedules by incorporating ENMAX's Wires Retail Access Program (WRAP) capital anomaly retirement in the calculation of the K-bar. Further, in response to the Commission's correspondence of November 19, 2020, ENMAX updated its distribution tariff rate schedules to account for the effect of the Commission's findings pursuant to ENMAX's 2019 distribution tariff Phase II application and approved rate design methodology.[4] Lastly, on December 8, 2020, ENMAX provided a further update rectifying an omission of not including the effect of the Phase II application in the DAS adjustment schedule, distribution tariff rate and typical bill comparisons.[5]

5. The Commission considers the record for this proceeding to have closed on December 8, 2020.

6. In reaching the determinations set out within this decision, the Commission 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.

3 Background

7. The PBR framework approved in Decision 20414-D01-2016 (Errata)[6] provides a rate-setting mechanism (price cap for electric distribution utilities and revenue-per-customer cap for gas distribution utilities) based on a formula that adjusts rates annually by means of an indexing mechanism that tracks the rate of inflation (I) that is relevant to the prices of inputs the utilities use, less a productivity offset (X). With the exception of specifically approved adjustments, as discussed further below, a utility's revenues are not linked to its costs during the PBR term.

8. In Decision 20414-D01-2016 (Errata), the Commission approved the continuation of certain PBR rate adjustments to enable the recovery of specific costs where certain criteria have been satisfied. These include an adjustment for certain flow-through costs that should be recovered from, or refunded to, customers directly (Y factors), and an adjustment to account for the effect of exogenous and material events for which the distribution utility has no other reasonable cost recovery or refund mechanism within the PBR plan (Z factor).

9. As was the case in previous-generation PBR plans, the Commission determined that a supplemental capital funding mechanism, in addition to revenue provided under I-X, is required for the 2018-2022 PBR plans. However, in place of the capital tracker mechanism employed in previous-generation PBR plans, the Commission determined that incremental capital funding

[3] Decision 25422-D01-2020: Anomaly Adjustment Applications in Rebasing the 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 25422, November 3, 2020.

[4] Decision 24820-D01-2020: ENMAX Power Corporation, 2019 Distribution Tariff Phase II Application, Proceeding 24820, August 28, 2020; subsequently considered by way of compliance filing in Proceeding 25861.

[5] Exhibit 25865-X0055.

[6] Decision 20414-D01-2016 (Errata): 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Proceeding 20414, February 6, 2017.

will be divided into two categories: Type 1 and Type 2 capital. For Type 1 capital, the Commission approved a modified capital tracker mechanism with narrow eligibility criteria, with the revenue requirement associated with approved amounts to be collected from ratepayers by way of a "K factor" adjustment to the annual PBR rate-setting formula. For Type 2 capital, the Commission approved a K-bar mechanism that provided an amount of capital funding for each year of the 2018-2022 PBR term plan based, in part, on capital additions made during the previous PBR term.[7]

10. Also in Decision 20414-D01-2016 (Errata), the Commission established that each of the distribution utilities must submit its PBR rate adjustment filing by September 10 of each year in order to facilitate annual implementation of rates by January 1 of the following year. The annual PBR rate adjustment filing deals with all issues relevant to the establishment of the PBR rates and T&Cs for a given year, such as:

- I factor and the resulting I-X index;
- K factor and K-bar factor adjustments related to approved Type 1 and Type 2 capital, respectively;
- Y factor adjustment to collect flow-through items that are not collected through separate riders;
- previously approved Z factors;
- billing determinants for each rate class;
- backup showing the application of the formula by rate class and resulting rate schedules;
- a copy of the Rule 005[8] filing filed in the current year as well as the return on equity (ROE) adjustment schedules for prior years;
- certain financial reporting requirements;
- changes proposed to T&Cs; and
- any other material relevant to the establishment of current year rates.

11. ENMAX's 2020 PBR rates were approved on an interim basis in accordance with this framework in Decision 24875-D01-2019.[9]

4 PBR rate adjustments

4.1 2021 PBR indices and annual adjustments

12. As detailed in Section 3, the current PBR plan for ENMAX provides a rate-setting mechanism based on a formula that adjusts rates annually by means of an indexing mechanism plus specifically approved adjustments. The annual parameters and adjustments utilized by ENMAX to arrive at its 2021 rates, and the Commission's assessment of the applied-for

[7] Decision 20414-D01-2016 (Errata), Section 6.4.2 (Type 1) and Section 6.4.3 (K-bar).
[8] Rule 005: *Annual Reporting Requirements of Financial and Operational Results*.
[9] Decision 24875-D01-2019: ENMAX Power Corporation, 2020 Annual Performance-Based Regulation Rate Adjustment, Proceeding 24875, December 16, 2019.

amounts, are detailed below. Additional discussion on select parameters is provided in the sections that follow.

I-X index

13. ENMAX calculated the 2021 I-X index to be 2.12 per cent,[10] by subtracting the approved X factor of 0.3 per cent[11] from the I factor of 2.42 per cent.

14. The I factor is calculated as a weighted average of two indexes published by Statistics Canada: one for labour costs and one for non-labour costs.[12] In Decision 24875-D01-2019, the Commission reiterated that the replacement of Canadian Socio-Economic Information Management System (CANSIM) tables with new data tables by Statistics Canada in 2018 did not warrant any changes to the approved I factor calculation methodology as long as the new tables contain the required data series.

15. The CCA pointed out that it is hard to verify the index numbers used in the I factor calculations because of the Statistics Canada ongoing updates to the published data. To address this concern, the CCA recommended all annual PBR rate adjustment filings to include a screen print of the index values taken from the Statistics Canada website.[13] ENMAX agreed that including a screenshot, or some other evidence of the Statistics Canada values as they are retrieved for the filing, has merit.[14]

16. The Commission has reviewed ENMAX's calculation of the 2021 I factor and finds it to be consistent with the methodology set out in Decision 20414-D01-2016 (Errata). Accordingly, the 2021 I factor of 2.42 per cent and the resulting I-X index of 2.12 per cent are approved.

17. In accordance with a past Commission direction,[15] ENMAX should use the unrevised actual index values filed in this proceeding as the basis for next year's inflation factor calculations. These values are provided in Appendix 3 to this decision. As well, to facilitate the review of the underlying Statistics Canada indexes, the Commission directs ENMAX to provide dated screenshots of the CANSIM tables used in determining its I factor in future annual PBR rate adjustment filings.

Y and Z factor materiality threshold

18. The Y and Z factor materiality threshold is the dollar value of a 40-basis point change in ROE on an after-tax basis calculated on the distribution utility's equity used to determine the final approved notional 2017 revenue requirement on which going-in rates were established. This dollar amount threshold is escalated by I-X annually, on a compounding basis.[16] ENMAX

10 Exhibit 25865-X0001, application, paragraph 22.
11 Decision 20414-D01-2016 (Errata), paragraph 5.
12 Decision 20414-D01-2016 (Errata), paragraph 8, and Appendix 5, Section 2, I factor, PDF pages 98-99.
13 Exhibit 25865-X0038, paragraphs 9-10.
14 Exhibit 25865-X0042, ENMAX reply argument, paragraph 4.
15 Decision 2012-237: Rate Regulation Initiative, Distribution Performance-Based Regulation, Proceeding 566, Application 1606029-1, September 12, 2012.
16 Decision 20414-D01-2016 (Errata), Appendix 5, Section 8, Z factor, PDF page 101.

calculated the Y and Z materiality threshold to be $1.91 million in 2021.[17] No party objected to these calculations.

19. The Commission has reviewed ENMAX's calculations of its 2021 Y and Z factor materiality threshold of $1.91 million and is satisfied that it has been calculated correctly. Accordingly, this threshold is approved.

Y factor

20. The Y factor allows a utility to flow through to customers costs that are either incurred at the direction of the Commission or meet specific criteria approved by the Commission, and are not otherwise included in a PBR plan. The Y factor includes costs that do not qualify for capital treatment or Z factor treatment for exogenous adjustments.[18] ENMAX applied for a Y factor amount of $1.95 million, inclusive of carrying costs.[19] No party objected to this amount.

21. The Commission has assessed the amounts included in ENMAX's applied-for Y factor and finds they were adequately supported, properly calculated and in compliance with previous Commission directions. The Commission has also reviewed ENMAX's Y factor carrying costs, and finds that they are properly calculated and consistent with the applicable provisions of Rule 023.[20] Accordingly, the applied-for Y factor amount is approved as filed.

Z factor

22. Z factors account for the impact of material exogenous events for which the company has no other reasonable cost recovery or refund mechanism within the PBR plan.[21] ENMAX did not apply for any Z factor adjustments in 2021.

Q value

23. Q value represents the percentage change in billing determinants. For electric distribution utilities under the price cap mechanism, this percentage change is calculated across all billing determinants, including energy, demand and the number of customers.[22] No party objected to ENMAX's applied-for Q value of -3.66 per cent.[23]

24. The Commission has reviewed ENMAX's calculation of its 2021 Q and finds it to be properly calculated and consistent with the approved methodology. Accordingly, the Commission approves ENMAX's 2021 Q value of -3.66 per cent. The Commission directs ENMAX to continue providing Q value calculations in its future annual PBR rate adjustment filings.

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17 Exhibit 25865-X0002, application, paragraph 31.
18 Decision 2012-237, paragraphs 617 and 631. Largely the same Y factor definition was adopted in Decision 20414-D01-2016 (Errata), Appendix 5, Section 3, Y factor, PDF page 99.
19 Exhibit 25865-X0002, application, paragraph 26.
20 Rule 023: *Rules respecting the payment of interest*.
21 Decision 2012-237, paragraphs 523-524.
22 Decision 2013-435: Distribution Performance-Based Regulation, 2013 Capital Tracker Applications, Proceeding 2131, Application 1608827-1, December 6, 2013, paragraph 499.
23 Exhibit 25865-X0002, application, paragraph 48.

K-bar factor

25. K-bar funding provides incremental Type 2 capital funding to supplement the revenues generated under the I-X mechanism.[24] 2018 K-bar was calculated by taking the difference between the revenue requirement associated with 2018 notional capital additions and the I-X related revenue for each project or program included in Type 2 capital.[25] For each year, the K-bar is calculated following similar steps as those for 2018, with adjustments made to account for the effects of inflation and productivity growth, growth in billing units (Q value), and changes to the weighted average cost of capital (WACC).[26] These updated parameters are to be used in the K-bar accounting test to calculate the amount of incremental Type 2 capital funding for a given year.

26. ENMAX has applied for the 2021 K-bar funding of $35.12 million, comprising its 2021 K-bar and 2018-2020 K-bar true-up, including associated carrying costs.[27] No party objected to ENMAX's applied-for K-bar funding.

27. The Commission has reviewed ENMAX's schedules showing the calculation of the 2021 K-bar amount and finds that it followed the methodology set out in Decision 22394-D01-2018. Therefore, the Commission approves ENMAX's 2021 K-bar of $35.12 million. The 2021 K-bar will be subject to a further true-up for the 2021 actual approved cost of debt.

K factor

28. In the current PBR plan, K factor is used to recover the Type 1 capital funding that provides additional funding, above that provided in base rates, for projects that meet the specific criteria established by the Commission.[28] Type 1 capital tracker projects can be approved on a placeholder basis if a utility submits an officer's certificate showing the internal approved forecast associated with the Type 1 capital tracker project for the upcoming year. K factor can also be used to deal with any remaining capital tracker true-up amounts from the prior generation PBR plan.

29. ENMAX currently has two Type 1 capital placeholders, approved in decisions 23892-D01-2018[29] and 24875-D01-2019, for the cost recovery of 90 per cent of the management-approved internal 2019 and 2020 forecasts of capital additions in the amounts of $18.81 million and $6.38 million, respectively. These costs are associated with relocation of ENMAX's infrastructure pursuant to The City of Calgary's Green Line Light Rail Transit (LRT) Project. The correspondingly approved incremental revenue requirement figures were $1.02 million for 2019 and $1.25 million for 2020.

30. In the present proceeding, ENMAX informed the Commission that it does not expect to incur any capital additions related to the Green Line LRT Project in 2021.[30] ENMAX requested

24 Decision 22394-D01-2018: Rebasing for the 2018-2022 PBR Plans for Alberta Electric and Gas Distribution Utilities, First Compliance Proceeding, Proceeding 22394, February 5, 2018, paragraph 167.
25 Decision 22394-D01-2018, paragraph 169.
26 Decision 22394-D01-2018, paragraph 223.
27 Exhibit 25865-X0046, Appendix 5, tab 1.0.
28 Decision 20414-D01-2016 (Errata), paragraph 198.
29 Decision 23892-D01-2018: ENMAX Power Corporation, 2019 Annual Performance-Based Regulation Rate Adjustment Filing, Proceeding 23892, December 21, 2018.
30 Exhibit 25865-X0020, paragraph 3.

approval of 2021 revenue requirement of $1.78 million, which represents 90 per cent of the total 2021 revenue requirement of $1.97 million associated with the Green Line LRT Project.[31] In this regard, ENMAX provided an internally approved forecast with an officer's certificate as part of its annual PBR rate adjustment filing.

Commission findings

31. The Commission accepts ENMAX's 2021 revenue requirement forecast in the amount of $1.97 million. The Commission notes that by way of a disposition letter in Proceeding 25765,[32] ENMAX was granted a request to combine its 2019 and 2020 true-up applications into a single application to be filed in Quarter 2 2021, which will consider the eligibility of this project for Type 1 capital treatment and the related true-up of actual costs. The Commission considers that the amount approved in this proceeding can also form part of the Commission's review of ENMAX's upcoming true-up application. ENMAX is therefore directed to provide the detailed analysis of its total 2019 and 2020 capital additions of $18.81 million and the associated 2021 revenue requirement amount of $1.97 million as part of that application.

4.1.1 Forecast billing determinants and variance analysis

32. Forecast billing determinants are generally used to allocate K, K-bar, Y and Z factors to rate classes and to calculate the resulting rate adjustments, and are also used in performing the annual use-per-customer adjustments for gas distribution utilities.

33. In Decision 23355-D02-2018,[33] the Commission directed ENMAX to continue to provide annual and monthly forecasts of billing determinants in its future annual PBR rate adjustment filings. Detailed 2021 billing determinant forecasts were provided in Appendix 5 of the application.[34] ENMAX indicated that its forecast was based on the same methodology approved in Decision 21508-D01-2017,[35] and applied throughout the PBR regime, with the exception of specific adjustments made to account for the COVID-19 pandemic. In this regard, ENMAX explained that in 2020 it had experienced lower than normal levels of energy consumption and demand usage for the Large Commercial Secondary – D310 (-12 per cent) and Large Commercial Primary – D410 (-14.6 per cent) rate classes and a higher level of energy consumption for the Residential – D100 rate class (+3.3 per cent). Therefore, ENMAX adjusted forecasts for these rate classes to reflect the expected changes in energy consumption.

34. Specifically, ENMAX determined the year-over-year change in energy consumption by rate class, for the periods of June 3 to June 30, 2019, and June 1 to June 28, 2020, and applied the resulting percentages to the energy consumption forecast. The chosen timeframe was selected as a result of the most recent actual information available up to the end of June 2020 and in order to minimize the impact of certain government mandated restrictions that attributed to the reduced

[31] Exhibit 25865-X0007, tab 8.0.

[32] Proceeding 25765: ENMAX Power Corporation request relating to the Type 1 capital placeholder true-up.

[33] Decision 23355-D02-2018: Rebasing for the 2018-2022 Performance-Based Regulation Plans for Alberta Electric and Gas Distribution Utilities, Second Compliance Proceeding, Proceeding 23355, October 10, 2018, paragraph 234.

[34] Exhibit 25865-X0007, Appendix 5, tab 13.0, 2021 billing determinants forecast. Subsequently updated in Exhibit 25865-X0046.

[35] Decision 21508-D01-2017: ENMAX Power Corporation, 2015-2017 Capital Tracker Application, Proceeding 21508, December 13, 2017.

energy loads.[36] ENMAX noted that "that this methodology is similar to how others in the industry are calculating the impact of COVID-19 on changing levels of energy consumption."[37]

35. No pandemic-related adjustments were made to the forecast for the period after July 1, 2021. Rather, post-July 1, 2021, ENMAX assumed an increase in the overall level of energy consumption for residential customers, as many businesses will incorporate work-from-home programs. Commercial customers (in D310 and D410 rate classes) were expected to see decreases in the overall level of energy consumption.

36. No party objected to the billing determinants forecast and the amendments proposed therein to account for the effect of the pandemic.

37. In Decision 23355-D02-2018, the Commission directed ENMAX to continue to provide information on any variances from forecast to actual billing determinants by rate class and identify the cause of variances larger than ± five per cent on an annual basis.[38] In the present application, ENMAX reconciled forecast and actual billing determinants from 2019.[39] There were variances larger than ± five per cent for energy consumption in Medium Commercial – D300 and Street Lighting – D500 rate classes. ENMAX explained that actual commercial demand was driven lower as a result of fewer sites, with a number of customers moving to a lower rate class. Street lighting difference was attributable to fewer light fixtures, coupled with the move to light-emitting diode lights. No party raised an issue in respect of the provided variances.

Commission findings

38. The Commission considers that variances from forecasts resulting from circumstances such as those described by ENMAX for 2019 may reasonably be expected. Such occurrences do not generally call into question the predictive value of the methodology used to generate such forecasts and ENMAX is directed to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify and explain the cause of variances larger than ± five per cent on an annual basis.

39. Based on its review and assessment of ENMAX's methodology and billing determinants in this proceeding, the Commission finds that the methodology employed and the resulting 2021 forecast billing determinants are reasonable.

5 2021 PBR rates

5.1 Distribution rates

40. In previous sections of this decision, the Commission approved individual components of the PBR framework, including the I-X index, Y factor amount, K factor placeholder for Type 1

[36] Exhibit 25865-X0037, EPC-UCA-2020OCT02-002, PDF page 4.
[37] Exhibit 25865-X0002, paragraph 54.
[38] Decision 23355-D02-2018, paragraph 232.
[39] Exhibit 25865-X0008, Appendix 6.

capital funding,[40] and K-bar factor, all of which result in annual adjustments to ENMAX's PBR rates. The Commission also approved ENMAX's forecast billing determinants.

41. ENMAX also provided bill impact schedules reflecting the 2021 proposed rates, inclusive of ENMAX's approved Phase II rate design methodology in Decision 24820-D01-2020, that will go into effect on January 1, 2021. ENMAX's estimated bill impacts for a typical customer are shown in the table below.

Table 1. Bill impacts of ENMAX's proposed 2020 distribution rates

Rate class description	Typical bill change (December 1, 2020, to January 1, 2021)			
	Distribution tariff charges[41]		Total charges (bundled)[42]	
	($)	(%)	($)	(%)
D100 Residential	0.59	1.13	0.66	0.63
D200 Small Commercial	0.70	0.41	0.78	0.21
D300 Medium Commercial	(40.60)	(5.51)	(45.11)	(3.05)
D310 Large Commercial-Secondary	194.71	1.20	216.34	0.61
D410 Large Commercial-Primary	(5,459.29)	(13.98)	(6,065.81)	(6.67)
D500 Street Lights	0.83	16.35	0.92	5.94

Source: Exhibit 25865-X0057, tab 1.0.

Commission findings

42. The Commission has reviewed the schedules setting out ENMAX's 2021 PBR rate calculations and observes that these calculations are consistent with its practices and methodologies previously accepted by the Commission during the current PBR term. The Commission therefore accepts the general principles and methodologies utilized by ENMAX for calculating its 2021 PBR rates.

43. The Commission has also reviewed the typical bill impacts from December 2020 to January 2021, in assessing the likelihood of rate shock resulting from the proposed 2021 PBR rates. The Commission observes that the month-over-month changes to total bundled customer bills from December 2020 to January 2021 are not expected to exceed 10 per cent for all rate classes. In the past, the Commission has generally considered a change of 10 per cent from the last approved rates to be the threshold potentially indicative of rate shock.

44. For the reasons set out above, the Commission approves ENMAX's 2021 PBR rates effective January 1, 2021 on an interim basis, subject to finalization of ENMAX's Phase II compliance filing currently under consideration in Proceeding 25861.

5.2 DAS adjustment rider

45. In the application, ENMAX requested approval to include a DAS adjustment rider to reconcile amounts related to: (i) 2017 K factor true-up; and, (ii) DAS adjustment rider true-up for 2019 and 2020.

40 Subject to the Commission's satisfactory review in ENMAX's first true-up application that the Green Line LRT Project meets the Type 1 capital criteria, as well as the prudence assessment of all related expenditures.
41 Distribution charges only, excluding retail and local access fee charges.
42 All charges, comprising distribution, retail and local access fee charges.

46. The 2017 K factor true-up is associated with ENMAX's PG4-A-4 Proactive Cable Replacement and PG4-A-8 Overhead Conductor Replacement projects and reflects the Commission's denial of capital tracker treatment for these projects pursuant to Decision 23102-D01-2019.[43] ENMAX recalculated the accounting test based on the approved capital tracker amounts and, as noted by the Commission in the table below, proposed to collect $2.24 million related to the 2017 K factor.

Table 2. 2017 K factor reconciliation

	Reconciliation	2017 ($ million)	Reference
1	Originally proposed total K factor	27.46	Proceeding 21508, Exhibit 21508-X0029, application, paragraph 22.
2	K factor amount approved in rates (60% * line 1)	16.48	Decision 22013-D01-2016,[44] paragraph 18.
3	Negotiated settlement agreement K factor (actual)	21.66	Proceeding 23694, Exhibit 23694-X0143, Appendix A, Schedule 2.0.
4	Final K factor reflecting projects denial	18.71	Exhibit 25865-X0010, Appendix 8, Schedule 2.0.
5	Difference (line 2 minus line 4)	2.24	

Note: The amounts are subject to rounding.

47. With respect to the DAS adjustment rider true-up for 2019 and 2020, ENMAX explained that a true-up is required as a result of volume differences over the collection period. ENMAX calculated the difference, using the approved forecast 2019 (July to December) and 2020 (January to March) billing determinants, between the revenue collected under the PBR rates in place for 2019 and 2020, and the revenue using the updated 2019 and 2020 PBR rates calculated in the present application. This difference resulted in a true-up of $0.04 million for 2019 and ($0.02) million for 2020 that ENMAX has included in the 2020 DAS adjustment rider.

48. In the application, ENMAX proposed to implement the DAS rider over the three-month period from January 1 to March 31, 2021, and calculated the total adjustment amount to be $2.47 million, inclusive of associated carrying costs. The following table shows the effect of the rider for each rate class.

Table 3. DAS rider amounts

Rate class description	2019 DAS adjustment rider true-up	2020 DAS adjustment rider true-up	2017 K factor disallowance	Carrying costs	Total adjustment
	($000)				
D100 Residential	(10.59)	15.39	1,158.58	114.39	1,277.76
D200 Small Commercial	(7.09)	10.98	153.96	15.20	173.05
D300 Medium Commercial	38.80	(26.60)	321.65	31.76	365.61
D310 Large Commercial-Secondary	11.30	(17.34)	480.55	47.45	521.96
D410 Large Commercial-Primary	5.13	(2.71)	106.57	10.52	119.51
D500 Street Lights	(0.05)	(1.72)	10.79	1.07	10.08
D600 Distributed Generation	-	-	4.01	0.40	4.41
Total	**37.50**	**(22.00)**	**2,236.12**	**220.78**	**2,472.38**

Source: Exhibit 25865-X0056, Appendix 7, Schedule 8.0.

[43] Decision 23102-D01-2019: Commission-Initiated Proceeding, METSCO's Risk-Based Asset Management Framework for ENMAX and EPCOR, Proceeding 23102, March 1, 2019.

[44] Decision 22013-D01-2016: ENMAX Power Corporation, 2017 Interim Distribution Access Service Rates, Proceeding 22013, December 22, 2016.

Commission findings

49. The Commission has reviewed ENMAX's calculations of the true-up amounts shown in Table 3 above and finds them reasonable and consistent with the past utilization of the DAS rider. The Commission accepts ENMAX's proposal of implementing the rider adjustment over the three-month period, from January 1 to March 31, 2021. Therefore, the Commission approves the DAS adjustment rider in the amount of $2.47 million, as filed.

50. In Decision 20414-D01-2016 (Errata), the Commission continued the direction from a previous decision that rate adjustments associated with K, K-bar, Y and Z factors would be calculated using forecast billing determinants, and that there would be no subsequent true-up to account for differences between the forecast billing determinants and actual billing determinants.[45] In its 2022 annual PBR rate adjustment application, or its next DAS rider application, whichever comes first, ENMAX is directed to explain whether its DAS adjustment rider true-up practice to account for the differences in volume is consistent with this direction.

6 Other matters

6.1 Hybrid deferral account

51. In Decision 24875-D01-2019, the Commission approved ENMAX's request to implement the treatment of its Alberta Electric System Operator (AESO) contribution amounts similar to the hybrid deferral account approach approved for FortisAlberta Inc. in Decision 23505-D01-2018.[46] Under this approach, any changes to historical AESO contribution amounts will be captured through a true-up mechanism by way of a deferral account. The incremental capital funding for new AESO contributions will continue to be provided through the K-bar. Specifics of the hybrid deferral account methodology are as follows:

- Projects from the 2015-2017 PBR term where a permit and licence (P&L) had been issued by December 31, 2017, would be subject to deferral account treatment by way of a new PG5[47] Deferral Account; and

- Projects that receive a P&L after December 31, 2017, would be managed under the incentive properties of K-bar.

52. In the 2020 annual PBR rate adjustment application, ENMAX identified two projects (No. 7 Sub 138-25 kilovolt (kV) Transformer Upgrade and No. 162 Substation 2nd 138-25 kV Transformer Addition) from the 2015-2017 PBR term for which a P&L had been issued by December 31, 2017. As such, these projects would be subject to the hybrid deferral account treatment and not included in the K-bar calculations. In response to a Commission IR, ENMAX stated that the final AESO construction contribution decision (CCD) for the two identified projects above were expected by the end of 2019 and in Q1 of 2020.[48] As such, the Commission

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45 Decision 20414-D01-2016 (Errata), page 93.
46 Decision 23505-D01-2018: Commission-Initiated Review and Variance of Decision 22741-D01-2018, Proceeding 23505, November 7, 2018.
47 Project Group 5: AESO Required Capital Contributions.
48 Proceeding 24875, Exhibit 24875-X0029, EPC-AUC-2019OCT09-004, PDF page 5.

directed ENMAX to reflect any forthcoming adjustments as part of its present 2021 annual PBR rate adjustment filing.

53. In the application, ENMAX confirmed that final CCD for the No. 162 Substation 2nd 138-25kV Transformer Addition Project was received in Q1 2020 and the associated capital expenditure contributions were incorporated in its application, as shown in Appendix 21. With regard to the No. 7 Sub 138-25kV Transformer Upgrade Project, ENMAX informed the Commission that the final CCD is expected to be received later in 2020 due to a minor adjustment required to the lightning protection system and proposed to reflect the final capital expenditure contribution in its 2022 annual PBR rate adjustment application. Further, ENMAX identified a third project (No. 31 Substation 13 kV Breaker Addition) that also qualifies for the deferral account treatment as the Commission issued a P&L on January 29, 2016. For each of the projects, ENMAX provided associated costs and contribution amounts that were already incurred, by way of Appendix 20.

54. ENMAX applied the annual adjustments for refunds or costs related to the AESO contributions made during the 2015-2017 PBR term to the historical rate base (i.e., the 2017 closing rate base) associated with the AESO Contributions Program. The difference between the revenue collected through going-in rates (escalated each year by I-X and Q) and the revenue requirement associated with related true-ups is the deferral true-up amount.

55. The aforementioned three PG5 projects result in a net increase in capital additions to rate base of $5.73 million in 2019. This results in a 2019 deferral account true-up refund of $0.25 million. With respect to 2020, the costs associated with the No. 162 Substation 2nd 138-25kV Transformer Addition incurred in Q1 of 2020 result in a net increase in capital additions to rate base of $0.11 million in 2020. This results in a 2020 deferral account true-up refund of $0.38 million. As shown in the table below, the total adjustment for the AESO Contribution Hybrid Deferral Account is a refund of $0.63 million,[49] plus associated carrying costs of $0.02 million.

Table 4. ENMAX's 2019 and 2020 hybrid deferral account

AESO Contributions Program	2019 hybrid deferral calculation ($ million)	2020 hybrid deferral calculation ($ million)
2018/2019 closing rate base	113.39	115.50
Add: Net additions	5.73	0.11
Less: Depreciation expense	(3.61)	(3.69)
2019/2020 closing rate base	115.50	111.92
Mid-year rate base	114.45	113.71
WACC (%)	5.47	5.47
Return	6.26	6.22
Depreciation	3.61	3.69
2019/2020 revenue requirement	9.87	9.91
2019/2020 revenue from PBR formula	10.12	10.29
2019/2020 shortfall (surplus)	**(0.25)**	**(0.38)**
Total 2019-2020 surplus	**(0.63)**	

Source: Proceeding 24875, Exhibit 24875-X0023, Appendix 21, tab 2.0.

49 Total shortfalls added for each year of $0.25M + $0.38M = $0.63M

56. No intervener objected to ENMAX's request for a hybrid deferral account treatment of the three project and associated calculations.

Commission findings

57. The Commission has reviewed ENMAX's calculations pertaining to the hybrid deferral account and finds them in alignment with the approved methodology and past practice. Accordingly, the Commission approves a refund of $0.63 million and directs ENMAX to reflect any forthcoming adjustments with regard to the three PG5 projects as part of its 2021 annual PBR rate adjustment filing.

6.2 Terms and conditions of service

58. As part of the application, ENMAX amended its distribution T&Cs to escalate certain amounts by the I-X index. Specifically, ENMAX adjusted its maximum investment levels (MILs) and service fees by the I-X for 2021.[50] Additionally, in accordance with the Commission direction[51] in Decision 24875-D01-2019, ENMAX created stand-alone fee and investment schedules to accompany its T&Cs.

Commission findings

59. The Commission has reviewed ENMAX's revised MILs in Appendix 15 of its customer T&Cs, and its 2021 revised supplementary service charge schedules in Appendix 16 of its customer T&Cs and finds the proposed increases to the MILs and supplementary service charges to be consistent with Decision 20414-D01-2016 (Errata).[52] However, the Commission notes that ENMAX comprehensively revised its customer T&Cs as part of its Phase II application in Proceeding 24820. This matter is subject to finalization and the Commission's approval in ENMAX's Phase II compliance application, currently under review in Proceeding 25861. Accordingly, the Commission approves ENMAX's customer T&Cs in this proceeding, as set out in Appendix 5 to this decision, effective January 1, 2021, on a interim basis.

6.3 Financial reporting requirements and senior officer attestation

60. In Decision 20414-D01-2016 (Errata), the Commission adopted the requirement from Decision 2012-237 that each distribution utility be required to provide the following financial information in its annual PBR rate adjustment filing:

(a) A copy of its Rule 005 filing.

(b) A schedule showing disallowed costs, excluded from a distribution utility's ROE.

(c) Attestations and certifications signed by a senior officer of the distribution utility.[53]

61. The Commission provided a detailed summary or description of each of the above requirements in Section 4.6 of Decision 23355-D02-2018.[54]

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50 Exhibits 25865-X0017 and 25865-X0018.
51 Decision 24875-D01-2019, paragraph 88.
52 Decision 20414-D01-2016 (Errata), Appendix 5, Section 6, Maximum investment levels, PDF page 100.
53 Decision 20414-D01-2016 (Errata), Appendix 5, Section 10, Financial reporting requirements, PDF pages 101-102.
54 Decision 23355-D02-2018, paragraphs 71-74.

62. ENMAX provided the required financial information: a copy of its 2019 Rule 005 filing,[55] a schedule showing disallowed costs,[56] and attestations and certifications signed by a senior officer.[57]

Commission findings

63. The Commission has reviewed the financial information provided by ENMAX and is satisfied that it has complied with the financial reporting requirements set out in Decision 20414-D01-2016 (Errata).

6.4 Finalizing the going-in rates and associated 2018 capital factors

64. As set out in Decision 20414-D01-2016 (Errata), the Commission set the going-in rates for the 2018-2022 PBR plans on the basis of a notional 2017 revenue requirement that was calculated using the actual pre-2017 costs, adjusted as required for anomalies.[58] However, the resulting going-in rates and associated 2018 capital factors (K-bar and K factors) were interim because they contained certain items that were either placeholders or subject to review and variance proceedings. In ENMAX's case the most notable items that required finalization were the proposed anomaly adjustments.

65. On November 3, 2020, the Commission issued Decision 25422-D01-2020, approving ENMAX's WRAP capital anomaly and directing ENMAX to reflect the approved amount in this proceeding. ENMAX complied with this direction on November 18, 2020.

66. On November 19, 2020, the Commission issued a letter on the record of this proceeding, notifying ENMAX of its intention to finalize the going-in rates and 2018 capital factors, as all outstanding proceedings and placeholders previously limiting the company's ability to finalize these rates have now been resolved.[59] In response, ENMAX stated that all applicable adjustments have been included in its present 2021 annual PBR rate adjustment schedules.[60]

Commission findings

67. The Commission has reviewed ENMAX's notional 2017 revenue requirement and 2018 capital factor schedules, and is satisfied all adjustments have been calculated correctly and are generally in alignment with the Commission's directions in Decision 20414-D01-2016 (Errata) and all subsequent decisions and directions impacting these calculations. Therefore, the Commission approves ENMAX's 2018 going-in rates and 2018 capital factor, K-bar, calculated in this proceeding,[61] as final.

55 Exhibit 25865-X0013.
56 Exhibit 25865-X0014.
57 Exhibits 25865-X0020 and 25865-X0021.
58 Decision 20414-D01-2016 (Errata), paragraph 46.
59 Exhibit 25866-X0053, AUC letter - Finalizing the going-in rates and associated 2018 capital factors.
60 Exhibit 25865-X0051, PDF page 1.
61 Exhibit 25865-X0052.01.

7 Order

68. It is hereby ordered that:

(1) The 2021 distribution rate schedules set out in Appendix 4 are approved for ENMAX Power Corporation, effective January 1, 2021.

(2) The distribution tariff terms and conditions, as set out in Appendix 5, are approved effective January 1, 2021.

Dated on December 18, 2020.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
ENMAX Power Corporation (ENMAX)
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA)

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair Commission staff N. Sawkiw (Commission counsel) A. Jukov C. Robertshaw

Appendix 2 – 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 a past Commission direction, ENMAX should use the unrevised actual index values filed in this proceeding as the basis for next year's inflation factor calculations. These values are provided in Appendix 3 to this decision. As well, to facilitate the review of the underlying Statistics Canada indexes, the Commission directs ENMAX to provide dated screenshots of the CANSIM tables used in determining its I factor in future annual PBR rate adjustment filings. .... paragraph 17

2. The Commission has reviewed ENMAX's calculation of its 2021 Q and finds it to be properly calculated and consistent with the approved methodology. Accordingly, the Commission approves ENMAX's 2021 Q value of -3.66 per cent. The Commission directs ENMAX to continue providing Q value calculations in its future annual PBR rate adjustment filings. .... paragraph 24

3. The Commission accepts ENMAX's 2021 revenue requirement forecast in the amount of $1.97 million. The Commission notes that by way of a disposition letter in Proceeding 25765, ENMAX was granted a request to combine its 2019 and 2020 true-up applications into a single application to be filed in Quarter 2 2021, which will consider the eligibility of this project for Type 1 capital treatment and the related true-up of actual costs. The Commission considers that the amount approved in this proceeding can also form part of the Commission's review of ENMAX's upcoming true up application. ENMAX is therefore directed to provide the detailed analysis of its total 2019 and 2020 capital additions of $18.81 million and the associated 2021 revenue requirement amount of $1.97 million as part of that application. .... paragraph 31

4. The Commission considers that variances from forecasts resulting from circumstances such as those described by ENMAX for 2019 may reasonably be expected. Such occurrences do not generally call into question the predictive value of the methodology used to generate such forecasts and ENMAX is directed to continue to provide information on any variances from forecast to actual billing determinants by rate class and to identify and explain the cause of variances larger than ± five per cent on an annual basis. .... paragraph 38

5. In Decision 20414-D01-2016 (Errata), the Commission continued the direction from a previous decision that rate adjustments associated with K, K-bar, Y and Z factors would be calculated using forecast billing determinants, and that there would be no subsequent true-up to account for differences between the forecast billing determinants and actual billing determinants. In its 2022 annual PBR rate adjustment application, or its next DAS rider application, whichever comes first, ENMAX is directed to explain whether its DAS adjustment rider true-up practice to account for the differences in volume is consistent with this direction. .... paragraph 50

6. The Commission has reviewed ENMAX's calculations pertaining to the hybrid deferral account and finds them in alignment with the approved methodology and past practice. Accordingly, the Commission approves a refund of $0.63 million and directs ENMAX to

reflect any forthcoming adjustments with regard to the three PG5 projects as part of its 2021 annual PBR rate adjustment filing. .... paragraph 57

Appendix 3 – Inflation indexes used in the 2020 I factor calculation

(return to text)

Date	Alberta CPI v41692327 (2002=100)	Alberta AWE v79311387 $	Average July to June		Year over year % change		2021 I factor %
			AB CPI (2002=100)	AB AWE $	AB CPI %	AB AWE %	
July 2018	141.80	1149.77					
August 2018	141.60	1159.73					
September 2018	141.10	1139.33					
October 2018	141.40	1142.15					
November 2018	140.70	1149.74					
December 2018	140.50	1141.83					
January 2019	140.50	1147.69					
February 2019	142.00	1141.15					
March 2019	143.10	1155.88					
April 2019	143.70	1143.80					
May 2019	144.00	1183.43					
June 2019	142.70	1169.85	141.93	1152.03			
July 2019	143.60	1161.51					
August 2019	143.40	1166.27					
September 2019	142.90	1174.41					
October 2019	143.60	1192.13					
November 2019	143.60	1171.31					
December 2019	143.70	1171.78					
January 2020	144.70	1187.29					
February 2020	145.50	1179.61					
March 2020	144.10	1169.04					
April 2020	143.00	1243.85					
May 2020	144.10	1250.08					
June 2020	145.00	1205.07	143.93	1189.36	1.41	3.24	**2.42**

Source: Statistics Canada website (http://www.statcan.gc.ca) accessed on August 27, 2020.

Appendix 4 – 2021 rate schedules

(return to text)

Appendix 4 - 2021
rate schedules

(consists of 19 pages)

Appendix 5 – Distribution tariff terms and conditions

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Appendix 5.1 - Terms and conditions

(consists of 78 pages)

Appendix 5.2 - Terms and conditions investı

(consists of 2 pages)

Appendix 5.3 - Terms and conditions fee sch

(consists of 4 pages)

ENMAX POWER CORPORATION ("EPC")

DISTRIBUTION TARIFF

RATE SCHEDULE

RATES IN EFFECT AS OF JANUARY 1, 2021

EPC DISTRIBUTION TARIFF RATE SCHEDULE

DISTRIBUTION TARIFF
RESIDENTIAL

RATE CODE D100

Rate Schedule for the provision of Electricity Services to residential Customers of a Retailer.

ELIGIBILITY

1. Sites which use Electricity Services for domestic purposes in separate and permanently metered single family dwelling units with each unit either metered separately or incorporated into a common building with other units.

2. As a single phase or three phase wire service supplied at a standard voltage normally available.

3. Sites eligible under 1 and 2 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$0.604888
System Usage Charge	per kWh	$0.012168
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.038763

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. No more than one additional unit of living quarters within a single family dwelling, such as a basement suite equipped with cooking facilities, may be provided Electricity Services through one Meter under Rate Code D100. If the dwelling contains more than one additional self-contained unit of living quarters, a Commercial Rate will apply unless a separate Meter is installed for each unit.

   All new construction in R2 or higher density areas shall have a separate Meter for each suite, or alternatively the Electricity Services may be invoiced at the appropriate commercial rate.

2. If a Residential Site has a garage with a separate meter, the garage will be assigned a commercial rate.

3. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
SMALL COMMERCIAL

RATE CODE D200

Rate Schedule for the provision of Electricity Services to small commercial Customers of a Retailer.

ELIGIBILITY

1. Commercial Sites where the Energy consumption is less than 5,000 kWh per month (includes all unmetered services that are not Rate Code D500).

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service and Facilities Charge	per day	$1.363865
System Usage Charge	per kWh	$0.010239
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.033688

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Temporary Construction/Service

   Construction and rental costs for necessary transformers and equipment required for any temporary Electricity Services (whether single or three phase, or whether served from an overhead or underground source), shall be payable by the Customer to EPC in advance and based on an EPC estimate. Construction costs include costs associated with:

   (a) up and down labour;

   (b) unsalvageable material;

   (c) vehicles; and

   (d) equipment.

2. Temporary Connection Service

   Where applied-for Connection Services are to be used for temporary purposes only, the Customer will pay EPC, in advance of the installation:

   (a) EPC's total cost of installation and removal of the Facilities required for the temporary service; and

   (b) the cost of unsalvageable material.

3. Unmetered Services

   For unmetered services where individual energy consumption is small and easily predicted, estimated consumption will be based on equipment nameplate rating and operational patterns.

4. If a Site that qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
MEDIUM COMMERCIAL

RATE CODE D300

Rate Schedule for the provision of Electricity Services to medium commercial Customers of a Retailer.

ELIGIBILITY

1. For Sites whose Energy consumption is equal to or greater than 5,000 kWh per month for at least six of the last 12 invoice periods, provided a peak demand greater than 150 kVA was not registered twice in the previous 365 days.

2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$7.581687
Facilities Charge	per day per kVA of Billing Demand	$0.051470
Non-Ratcheted Demand Charge	per day per kVA of Metered Demand	$0.049609
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.256301
Variable Charge	per kWh	$0.009020

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period;

(b) "Ratchet Demand" is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period; and

(c) “Contract Demand” is the kVA contracted for by the Customer.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. Non-Standard Residential “Bulk-Metering”.
2. Bulk Metering is the metering of multiple-unit residential occupancies under one corporate identity, (e.g., town housing, apartments, mobile home parks). Where bulk-metering exists, the Customer shall not re-sell electricity, but may include electricity as part of the rental charge and not separate therefrom.
3. Includes Medium Commercial Sites served at primary voltage that existed prior to November 2004 rate class changes.
4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).
5. D300 Primary Voltage Service Customers
    a. For locations or buildings that receive primary voltage service, there will be a transformation credit of $1.559004 per day applied to the Service Charge, and a transformation credit of $0.010778 per day per kVA of Billing Demand applied to the Facilities Charge.
    b. The transformation credit is applicable only to D300 sites receiving primary voltage service prior to January 1, 2009.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
LARGE COMMERCIAL - SECONDARY

RATE CODE D310

Rate Schedule for the provision of Electricity Services to large commercial (secondary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that registered a monthly peak demand greater than 150 kVA twice in the previous 365 days and served at secondary voltage.

2. Sites eligible under 1 that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	\$20.471867
Facilities Charge	per day per kVA of Billing Demand	\$0.121088
Non-Ratcheted Demand Charge	per day per kVA of Metered Demand	\$0.039835
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	\$0.337820
Variable Charge On Peak	per kWh	\$0.011807
Variable Charge Off Peak	per kWh	\$0.009022

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) “Ratchet Demand” is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) “Contract Demand” is the kVA contracted for by the Customer.

“On Peak” is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

“Off Peak” is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all service supplied under this Tariff.

OTHER

If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
LARGE COMMERCIAL - PRIMARY

RATE CODE D410

Rate Schedule for the provision of Electricity Services to large commercial (primary) Customers of a Retailer.

ELIGIBILITY

1. For Electricity Services that are served at primary voltage.
2. Sites eligible under 1 above that qualify as a Micro-Generator under the Micro-Generation Regulation.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$23.617167
Facilities Charge	per day per kVA of Billing Demand	$0.016477
Non-Ratcheted Demand Charge	per day per kVA of Metered Demand	$0.047501
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Demand Charge	per day per kVA of Billing Demand	$0.288054
Variable Charge On Peak	per kWh	$0.009630
Variable Charge Off Peak	per kWh	$0.007482

Where

kVA of "Billing Demand" is defined as the greater of "Metered", "Ratchet" or "Contract" Demand:

(a) "Metered Demand" is the actual metered demand in the Tariff bill period,

(b) “Ratchet Demand” is 90% of the highest kVA demand in the last 365 days ending with the last day of the Tariff bill period,

(c) “Contract Demand” is the kVA contracted for by the Customer,

“On Peak” is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition),

“Off Peak” is all Energy consumption not consumed in On Peak hours.

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

1. The Customer is responsible for supplying all transformers whether owned by Customer or rented.
2. “Primary Metering” shall be metering at EPC’s primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.
3. Multi-Sites
   a) For Customers that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged based on Rate Code D410.
   b) For Customers that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged based on Rate Code D410 provided the service connections are:
      i) positioned on adjacent and contiguous locations;
      ii) not separated by private or public property or right-of-way; and
      iii) operated as one single unit.

4. If a Site qualifies as a Micro-Generator, rate charges will only apply to energy inflow into the Site (i.e. no outflow charges).

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
STREETLIGHTS

RATE CODE D500

Rate Schedule for the provision of Electricity Services to Customers of a Retailer.

ELIGIBILITY

For all photo cell controlled lighting services including all streetlights, traffic sign lighting, roadway lighting and lane rental lighting. Services with photo cell controlled lighting will not be eligible for a Meter.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Fixture Charge	per day per fixture	$0.071765
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
Variable Charge	per kWh	$0.058655

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
LARGE DISTRIBUTED GENERATION

RATE CODE D600

Rate Schedule for the provision of Electricity Services to Sites with on-site generation with a minimum export capacity of 1,000 kVA.

ELIGIBILITY

1. For services with on-site generation connected in parallel with the EPC Electric Distribution System with a minimum export capacity of 1,000 kVA.

2. For Electricity Services that are served at primary voltage.

3. For sites equipped with bi-directional interval recording metering.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$26.969704
Dedicated Facilities Charge	per day	customer specific
System Usage Charge On Peak	per kWh	$0.010173
System Usage Charge Off Peak	per kWh	$0.000000
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs/Credits	$	Flow through

1. The customer specific Dedicated Facilities Charge daily amount will be determined as follows:

   Dedicated Facilities Charge = ((DFA + GA) x (CRF + OMA))/365 days.

   Where:

   a) DFA = current cost of dedicated feeder assets

b) GA = general assets associated with DFA and equal to 10.8% of DFA

c) CRF = Capital Recovery Percentage Factor based on EPC's weighted cost of capital and approved depreciation rate.

d) OMA = Operation, maintenance and administration factor equal to 3.1% of DFA.

The customer specific Dedicated Facilities Charge daily amount will be outlined in the Interconnection Agreement which will also include the term of the Agreement and an annual inflation adjustment.

2. The System Usage Charge will be determined using the net of the energy inflow and energy outflow at the Meter(s). System Usage Charge will be waived for sites that only have dedicated facilities and do not use the EPC primary feeder system.

3. "On Peak" is all Energy consumption from 8 a.m. to 9 p.m. Monday to Friday inclusive, excluding statutory holidays (as according to the ISO Rules definition), "Off Peak" is all Energy consumption not consumed in On Peak hours.

4. Flow-Through of ISO Costs/Credits will be determined by applying the ISO DTS rate and/or STS rate (and any applicable riders) to the difference between the POD billing determinants with and without the site(s) billing determinants.

5. An initial fee will be charged for the incremental cost of bi-directional meter(s).

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of EPC form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

OTHER

5. The Customer is responsible for supplying all transformers whether owned by customer or rented.

6. "Primary Metering" shall be metering at EPC's primary distribution voltage with any subsequent transformation being the sole responsibility of the Customer.

7. Multi-Site Locations

   c) For locations or buildings that have a normally used service connection (preferred service) and a second service connection used strictly as a backup service (alternate service), the demands of the two service connections will be totaled on an interval basis and charged on Rate Code D600.

   d) For locations that use more than one service connection on a regular basis, demands of all the service connections will be totaled on an interval basis and charged on Rate Code D600.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DISTRIBUTION TARIFF
TRANSMISSION CONNECTED

RATE CODE D700

Rate Schedule for the provision of Distribution Access Service to Customers of a Retailer that are connected directly to EPC Facilities at a transmission voltage.

RATE

COMPONENT TYPE	UNIT	PRICE
DISTRIBUTION CHARGE FOR DISTRIBUTION ACCESS SERVICE		
Service Charge	per day	$26.969704
TRANSMISSION CHARGE FOR SYSTEM ACCESS SERVICE		
ISO Costs	$	Flow through

INVOICE PERIOD

Monthly, from the date of the last invoice to the date of the current invoice.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Rate Schedule and apply to all Electricity Services supplied under this Tariff.

LOCAL ACCESS FEE (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is collected by EPC on behalf of the City for all Sites located within the municipal boundaries of the City of Calgary.

DAS ADJUSTMENT RIDER

This is a rider to charge/refund the difference between DAS Adjustment Rider amounts collected between July 1, 2019 to December 31, 2019 and the amounts approved as per AUC Decision 23892-D01-2018, amounts collected between January 1, 2020 to March 31, 2020 and the amounts approved as per AUC Decision 24875-D01-2019, and the amounts approved as per AUC Decision 24761-D01-2019. The adjustment is effective January 1, 2021 to March 31, 2021.

ELIGIBILITY

Rider will apply to all sites.

RIDER

RATE CLASS DESCRIPTION	RATE CODE	UNIT	PRICE
Residential	D100	% DAS	3.50%
Small Commercial	D200	% DAS	3.79%
Medium Commercial	D300	% DAS	3.87%
Large Commercial – Secondary	D310	% DAS	4.36%
Large Commercial – Primary	D410	% DAS	4.90%
Streetlights	D500	% DAS	1.51%
Large Distributed Generation	D600	% DAS	3.89%

Local Access Fee (LAF)

The LAF is a surcharge imposed by the City of Calgary and is not approved by the Alberta Utilities Commission. The LAF is applicable to all services located within the City of Calgary.

ENMAX POWER CORPORATION

DISTRIBUTION TARIFF

Terms and Conditions

Effective January 1, 2021

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PART A GENERAL

SECTION 1 DEFINITIONS

The following words and phrases, whenever used in these Terms and Conditions, a Rate Schedule, the Fee Schedule, the Investment Schedule, a Retail Access Services Agreement or an Interconnection Agreement, shall have the respective meanings set out below:

"***Arbitration Act***" means the *Arbitration Act* (Alberta);

"**AUC**" means the Alberta Utilities Commission;

"**AUC *Rule 004***" means the Alberta Tariff Billing Code Rules as established, amended from time to time and approved by the AUC under the authority of the *EUA*;

"**AUC *Rule 021***" means the Settlement System Code Rules as established, amended from time to time and approved by the AUC under the authority of the *EUA*;

"**Billing Demand**" means the demand as defined in the EPC Distribution Tariff Rate Schedule;

"**Business Day**" means any day other than a Saturday, Sunday or a Statutory holiday in the Province of Alberta;

"**Connected Load**" means in relation to a Site, the sum of the capacities or ratings of the Energy consuming apparatus connected to EPC's Electric Distribution System at the Site;

"**Connection Services**" means services provided by EPC to Customers, which will allow for the transport of Energy to the Customer's facilities and includes, without limitation, Meter services, Meter data management and other related services as offered by EPC from time to time, as set out in these Terms and Conditions;

"**Customer**" means a Person purchasing electricity for the Person's own use, a Transmission Connected Customer, a Distributed Generator, or a Developer, as context requires;

"**De-Energize**", "**De-Energized**" **or** "**De-Energization**" means the disconnection of metering or electrical equipment from the Electric Distribution System to prevent Energy from flowing to the Site;

"**Default Supplier**" means a Retailer appointed by an owner pursuant to Section 3 of the *Roles, Relationships and Responsibilities Regulation* (Alberta);

"**Demand**" means the rate at which Energy is delivered to or by a system (expressed in kVA) at a given instant or average over any designated period of time;

"**Developer**" means a Person who is developing the land or structure, or both, on which the Facilities are being installed;

"**Distributed Generation**" means a generating unit that is interconnected with the Facilities;

"**Distributed Generation Interconnection Services**" means services provided by EPC which will allow for the Distributed Generator's delivery of Energy to the Facilities as set out in these Terms and Conditions;

"**Distributed Generator**" means a Person who delivers Energy to the Facilities as set out in these Terms and Conditions and includes a Micro-Generator;

"**Distribution Access Service**" means Electric Distribution Service which has the meaning given to it by the EUA;

"**Distribution Tariff**" means a document prepared by EPC and approved by the AUC that sets out:

a) Rate Schedules, and
b) Terms and Conditions;

"**Electric Distribution System**" means the plant, works, equipment, systems and services necessary to distribute electricity in a service area, but does not include a generating unit or a transmission facility;

"**Electricity Services** "means services associated with providing electricity to a Person, including:

a) the Exchange of Energy,

b) making financial arrangements to manage financial risk associated with the pool price,

c) Distribution Access Service,

d) System Access Service,

e) ancillary services,

f) billing,

g) metering,

h) performing Load Settlement, and

i) any other services specified in the regulations made under Section 115 of the

j) *EUA*;

k) Distribution Access Service,

l) System Access Service,

m) ancillary services,

n) billing,

o) metering,

p) performing Load Settlement, and

q) any other services specified in the regulations made under Section 115 of the

r) *EUA*;

"**Eligible Customer**" has the meaning given to it by the *EUA*;

"**Emergency**" means:

a) an abnormal system condition requiring manual or automatic action to maintain system frequency, or to prevent loss of firm Load, equipment damage, or tripping of system elements that could adversely affect the reliability of the Electric Distribution System or the safety of Persons or property,

b) a fuel shortage requiring departure from normal operating procedures in order to minimize the use of fuel,

c) a condition that requires implementation of an Emergency operations system as defined in the ISO's operating policy and procedures, or

d) any other condition or situation that EPC or the ISO deems imminently likely to endanger life or property or to affect or impair EPC's Electric Distribution System or the electrical systems of others to which EPC's Electric Distribution System is directly or indirectly connected. Such a condition or situation may include but is not limited to potential overloading on EPC's Electric Distribution System, Facilities, transmission and/or distribution circuits, or unusual operating conditions on either EPC's Electric Distribution System, Facilities, transmission or distribution circuits or on those of an indirectly connected electrical system, or conditions such that EPC is unable to deliver Energy for a Customer or Retailer without jeopardizing EPC's Electric Distribution System, Facilities, transmission or distribution circuits or those of an indirectly connected electrical system;

"**Energize**", "**Energized**" **or** "**Energization**" means the connection of metering or electrical equipment to the Electric Distribution System to permit Energy to flow to the Site and includes any derivation of this word, as the context requires;

"**Energy**" means the capability of electricity to do work, measured in kilowatt hours;

"**ENMAX**" means ENMAX Corporation;

"**EPC**" means ENMAX Power Corporation and includes a Person, if any, authorized to act on its behalf under the *EUA*. Where in these Terms and Conditions reference is made to the EPC obligation to provide or own meters, such obligation will include a commercial arrangement where such function is outsourced to a third party, as contemplated by Section 104 of the EUA.

"**Exchange**" means to provide electric Energy to or receive electric Energy from the IES;

"EUA" means the *Electric Utilities Act*, (Alberta);

"**Facilities**" means EPC's physical facilities including, without limitation, transmission and distribution lines, wires, transformers, Meters, Meter reading devices, Load Limiting Devices and other electrical apparatus;

"**Fee Schedule**" means the schedule of fees attached to and forming part of these Terms and Conditions which sets out the charges for the provision of Connection Services, Distributed Generation Interconnection Services, Transmission Connected Services or Retail Access Services, as amended from time to time;

"**Force Majeure**" means acts of God, strikes, walkouts, lockouts or other industrial disturbances, acts of a public enemy, wars, blockades, insurrections, riots, pandemics, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, inclement weather, laws, orders, restraints or acts of courts or other public, civil or military authorities, civil disturbances, explosions, breakdown or accident or necessity of repairs to equipment or lines of the electric transmission and distribution systems, loss, diminution or impairment of electrical service from generating plants, suppliers or the systems of others with which the Electric Distribution System is interconnected, failure of any supplier, Customer or Retailer to perform, failure, curtailment, interruption or reduction of the transmission or Electric Distribution Systems' capacity, and any other event or circumstance, whether of the kind herein enumerated or otherwise, not reasonably within the control of EPC., In no event shall the lack of finances of EPC or inability to perform due to financial condition of EPC or decisions or orders made by the AUC in the normal course of it exercising its authority over EPC constitute Force Majeure;

"**IES**" means the Interconnected Electric System which is all transmission facilities and all Electric Distribution Systems in Alberta that are interconnected, but does not include an Electric Distribution System or a transmission facility within the service area of the City of Medicine Hat or a subsidiary of the City of Medicine Hat, unless the City of Medicine Hat passes a bylaw that is approved by the Lieutenant Governor in Council under Section 138 of the EUA;

"**Interconnection Agreement**" means an agreement between EPC and a Distributed Generator, which sets the terms upon which EPC provides Distributed Generation Interconnection Services to the Distributed Generator and the associated Rate Schedule and Fee Schedule;

"**Investment Schedule**" means the schedule attached to and forming part of these Terms and Conditions which sets out EPC's investment in service connection(s) to a property or building, as amended from time to time;

"**Invoice Date**" means the date as indicated on EPC's invoice;

"**Islanded Operation**" means a condition in which a portion of the Facilities is electrically separated from the rest of the Facilities and is Energized by one or more Distributed Generators;

"**ISO**" means the Independent System Operator established in the *EUA* to carry out the duties of the Independent System Operator under the *EUA* and carrying on business as the Alberta Electric System Operator;

"**kVA**" means kilovolt ampere or kilovolt amperes;

"**Load**" means the Demand and Energy delivered or required to be delivered to a Site;

"**Load Limiting Device**" means a device that limits or reduces the electric current provided to the Customer;

"**Load Settlement**" means the functions set out in AUC *Rule 021*;

"**LSA**" means Load Settlement Agent, which is the entity conducting Load Settlement calculations for a particular Load Settlement zone;

"**MDM**" means Meter Data Manager which is the entity responsible for collecting metering data, correcting and validating interval and cumulative metering data, storing historic data, and reporting Load and consumption data and corresponding time periods. MDM functions are governed in AUC *Rule 021* and the *Electricity and Gas Inspections Act* and Regulations (Canada);

"Meter" is the apparatus and associated equipment, which measure active Energy or reactive Energy or both, as approved by Measurement Canada;

"Micro-Generation Regulation" means the *Micro-Generation Regulation* (Alberta);

"**Micro-Generator**" means micro-generator as defined in the *Micro-Generation Regulation*;

"**Minimum Contract Demand**" is the minimum kVA contracted for by the Customer;

"**MSP**" means Meter Service Provider which is the entity responsible for installing, removing, repair and maintenance of meters;

"**Network**" means the geographic area located in and around the downtown core of the City of Calgary as may be amended by EPC from time to time and as described in the Network Servicing Policies and Guidelines;

"**Network Servicing Policies and Guidelines**" means the network policies and guidelines document referenced in these Terms and Conditions and posted on the EPC website;

"**Operating Procedures**" means the procedures for the operation of both the Distributed Generator's facilities and the Facilities relating to an interconnection, which may be revised from time to time by EPC upon written notice to the Distributed Generator and attached as a schedule to an Interconnection Agreement;

"**Optional Facilities**" means Facilities requested by the Customer that are, in the opinion of EPC, beyond what is required to provide safe, reliable and economic service consistent with current EPC standard practice or are expected to cause increased operation and maintenance expenses to EPC;

"**Parties**" means EPC, the Customer, Retailer, or any other Person taking any services, under this Distribution Tariff and these Terms and Conditions and "**Party**" means any one of them;

"**PCC**" means Point of Common Coupling which is the point at which the Facilities are connected to the Distributed Generator's facilities or conductors, and where any transfer of electric Energy between the Distributed Generator and EPC takes place;

"**Person**" means an individual, firm, partnership, association, joint venture, corporation, trustee, executor, administrator or legal representative;

"**PFAM**" means Post Final Adjustment Mechanism as defined in AUC *Rule 021*.

"**POD**" means Point of Delivery which is the metered interconnection point between the transmission system and the distribution system;

"**Power Factor**" means the ratio of real or productive power measured in kilowatts (kW) to total or apparent power measured in kVA;

"**Power Pool**" means the scheme operated by the ISO for:

a) Exchange of electric Energy, and

b) financial settlement for the Exchange of electric Energy;

"**Ratchet Demand**" means 90% of the highest kVA Demand in the last 365 days ending with the last day of the Distribution Tariff bill period as defined in AUC *Rule 004*;

"**Rate Schedule**" means a schedule forming part of the Distribution Tariff that sets out the charges to Retailers, Distributed Generators or Transmission Connected Customers for the provision of Distributed Generation Interconnection Services, Transmission Connected Services or Retail Access Services as approved by the AUC;

"**Re-Energize**" **or** "**Re-Energization**" means the reconnection of metering or electrical equipment to the Electric Distribution System, which allows Energy to flow to a Site;

"**Regulated Rate Provider**" **or** "**RRP**" means the owner of an Electric Distribution System, or a Person authorized by the owner that provides Electricity Services to Eligible Customers in the owner's service area under a Regulated Rate Tariff;

"**Regulated Rate Tariff**" means a tariff which provides for a transition rate or a flow- through rate and applies to any Eligible Customer;

"**Requirements for Distribution Wires Access**" means the requirements for distribution wires access document referenced in these Terms and Conditions and posted on the EPC website;

"**Retail Access Services**" means the services provided by EPC to Retailers pursuant to these Terms and Conditions and includes without limitation Distribution Access Service, Meter data management, Load Settlement, and Meter services and other related services as offered by EPC from time to time;

"**Retail Access Services Agreement**" means an agreement between EPC and a Retailer, which sets forth the terms upon which EPC provides Retail Access Services to the Retailer and whereby the Retailer agrees to these Terms and Conditions and the associated Rate Schedule;

"**Retail Electricity Services**" means Electricity Services provided directly to a Customer but does not include Electricity Services provided to Eligible Customers under a Regulated Rate Tariff;

"**Retailer**" means a Person who sells or provides Electricity Services, including a RRP and Default Supplier and includes an affiliated Retailer;

"**Retailer of Record**" means the Retailer that the Load Settlement system recognizes as providing Retail Electricity Services to a given Site for a given day;

"**Service Connection**" means the physical connections of the Facilities to the facilities of a Customer;

"**Settlement Zone**" means the collection of Sites that are jointly settled by a Load Settlement system;

"**Site**" means a unique end use service delivery point;

"**Site ID Catalogue**" means the electronic file containing Site Identification Numbers and location information for all Sites to which EPC provides delivery services;

"**Site Identification Number**" means a unique identification number assigned by EPC to each Site;

"**System Access Service**" means the service obtained from the transmission system;

"**Terms and Conditions**" means these Terms and Conditions for any services, as amended from time to time;

"**Transmission Connected Customer**" means for the purpose of exemption from distribution charges as defined in the Rate Schedule:

a) a Customer whose Service Connection is at a transmission voltage of 69 kV and above, or

b) a Customer whose plant Site is contiguous with a transmission facility and takes service directly from the transmission facility, or through a transformer which is directly connected to the transmission facility;

"**Transmission Connected Services**" means the services provided by EPC to Transmission Connected Customers pursuant to these Terms and Conditions and includes, without limitation, Meter services, Meter data management and other related services as offered by EPC from time to time; and

"**UFE**" means unaccounted for Energy which is the difference between:

a) the Electric Distribution System total Energy for the hour, and

b) the sum of the allocated hourly Energy at the Site, plus their allocated losses.

SECTION 2 INTERPRETATION

2.1 Conflicts

If there is any conflict or ambiguity between a provision expressly set out in a Retail Access Services Agreement, an Interconnection Agreement, Rate Schedule, or Technical Guidelines and these Terms and Conditions, the provisions of these Terms and Conditions shall govern to the extent of the conflict or ambiguity.

2.2 Headings

The division of these Terms and Conditions into sections, subsections and other subdivisions and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of these Terms and Conditions.

2.3 Acts and Regulations

The reference to a legislative Act or regulations includes regulations enacted thereunder, and any supplements, amendments or replacements.

SECTION 3 GENERAL PROVISIONS

3.1 AUC Approval

These Terms and Conditions form part of EPC's Distribution Tariff and have been approved by the AUC.

EPC can only amend these Terms and Conditions by obtaining the approval of the AUC. EPC may amend these Terms and Conditions by filing a notice of amendment with the AUC. Included in the notice to the AUC shall be notification of which Customer groups are affected by the amendment and an explanation of how affected Customers will be notified of the amendments. The AUC will either accept the notice of amendment to the Terms and Conditions within 60 days after such notice is filed or will direct a further process to deal with the requested change. Where the AUC has accepted the amendment, that amendment shall be effective, and these Terms and Conditions shall be so amended on the first day following the end of the 60-day notice period referred to herein or in accordance with any further process selected by the AUC.

3.2 Acceptance of Terms and Conditions

The taking of any services by a Customer or Retailer under these Terms and Conditions constitutes acceptance by the Customer or Retailer of these Terms and Conditions and assumption of all obligations set forth herein with respect to that service.

3.3 Modification of Terms and Conditions

No agent or employee of EPC is authorized to modify or change these Terms and Conditions or the Rate Schedule, or to bind EPC to perform in any manner inconsistent with these Terms and Conditions or the Rate Schedule.

3.4 Collection of Taxes and Fees

EPC shall collect franchise fees, and sales, excise, or other taxes imposed by governmental authorities with respect to any service. The Retailer shall be responsible for identifying and requesting any exemption from the collection of any tax by filing appropriate documentation with EPC.

3.5 Payment of Invoice

All fees, rates and charges required to be paid under these Terms and Conditions shall be paid following receipt of an invoice for the fees, rates and charges. An invoice for a fee based service may be issued to a Customer by a Retailer on behalf of EPC or directly by EPC. Transactional charges include one-time charges as defined in AUC *Rule* 004. Customers or Retailers shall be invoiced for fee based services according to the fees set out in the Fee Schedule and in accordance with these Terms and Conditions.

Invoices shall be deemed rendered, and other notices duly given when delivered to a Party personally, when mailed to or left at the premises where service is provided or the last known address of the Party or when delivered to the address identified pursuant to these Terms and Conditions. Failure to receive such an invoice from EPC will not entitle the Party to any delay in the settlement of each account nor to any extension of the date after which does a late payment charge become applicable. In the case of a dispute between EPC and a Party, the Party shall be expected to make payment or settlement as originally arranged and agreed to, pending the resolution of the dispute.

Payment shall be made in a form as determined by EPC.

Late payment penalties, at a rate established by EPC and specified in the invoice, will be applicable to the total current charges outstanding, no less than 25 days following the Invoice Date. Parties who fail to make payments on time are subject to normal credit action, including, but not limited to:

a) reminder letters;
b) telephone notification;
c) use of collection agencies;
d) requiring prepayment before additional service;
e) withholding additional service; and
f) legal action.

3.6 Underpayments

Underpayments of any amount are treated as normal receivables outstanding.

3.7 Dishonored Payments

EPC may assess a dishonored payment fee, as outlined in the Fee Schedule, to any Party whose payment to EPC is dishonored by any financial institution. Receipt by EPC of a payment instrument that is subsequently dishonored or refused payment or returned by a financial institution shall not be considered valid payment.

3.8 Credit and Prepayment

Subject to these Terms and Conditions, prior to EPC agreeing to provide credit to a Party, the

Party must satisfy EPC that the Party is capable of meeting its obligations by satisfying either credit or security requirements as follows:

a) Credit

Provide information necessary to establish and monitor ability to pay.

b) Security

Provide and maintain one of the following forms of security (in EPC's sole discretion):

i) a satisfactory guarantee of payment;

ii) a satisfactory irrevocable letter of credit; or

iii) a cash deposit.

Service on credit may be withheld if the Party has outstanding accounts for previous EPC service.

Parties not extended credit are required to prepay for services.

Notwithstanding any credit or security arrangements, EPC, at its sole discretion, may require full or partial prepayment as a pre-condition to providing any services.

3.9 Customer Facilities

The Customer shall be responsible for the installation and condition of Customer owned equipment and facilities on a Site, or on premises controlled or occupied by the Customer.

EPC will retain ownership of its equipment and Facilities whether affixed to a Customer's facilities or not.

3.10 Service Calls

EPC will require a Customer to pay for a Customer-requested service call if the reason for the request relates to the Customer's operations, or facilities.

3.11 Law

These Terms and Conditions, the Retail Access Services Agreement and any Interconnection Agreement shall be governed by the laws of the Province of Alberta and the federal laws of Canada applicable in the Province of Alberta, without regard to principles of conflicts of laws. Any lawsuit arising in connection with these Terms and Conditions, the Retail Access Services Agreement or an Interconnection Agreement shall be brought in the courts of the Province of Alberta.

3.12 Notices

Unless otherwise stated herein, all notices, demands or requests required or permitted under these Terms and Conditions, a Retail Access Services Agreement or an Interconnection Agreement shall be in writing and shall be personally delivered, mailed or delivered by facsimile transmission (with the original transmitted by any of the other aforementioned delivery methods) addressed as follows:

a) if to the Customer, the address and the addressee on record with EPC;

b) if to the Retailer, the address and the addressee set out in the Retail Access Services Agreement between the Retailer and EPC;

c) if to the Distributed Generator, the address and the addressee on record with EPC;

d) if to the Transmission Connected Customer, the address and the addressee on record with EPC; and

e) if to EPC: ENMAX Power Corporation
ENMAX Place
141 – 50th Avenue SE Calgary, Alberta
T2G 4S7

A Party may change the address or addressee from time to time by giving written notice of such change as set out in this Section. Any notice, demand or request made, given or delivered hereunder is considered delivered: when sent by facsimile, on the next Business Day following a confirmed facsimile; when mailed, at the end of the fourth Business Day after mailing; or when hand delivered, at the time of delivery where proof of delivery date is provided.

All general operational notifications will be communicated electronically.

3.13 Default Supplier

EPC has appointed ENMAX Energy Corporation as its Default Supplier. The Default Supplier must provide Retail Electricity Services to a Customer, that is not an Eligible Customer, where the Customer is unable to:

a) continue to purchase Retail Electricity Services from the Customer's Retailer for any reason; or

b) obtain Retail Electricity Services for any reason.

SECTION 4 CONNECTIONS

4.1 Interruptions

Whenever EPC reasonably determines, or when directed by the ISO, EPC may discontinue or otherwise curtail, interrupt or reduce Connection Services, Transmission Connected Services or Distributed Generation Interconnection Services:

a) to facilitate construction, installation, maintenance, repair, replacement or inspection of any of the Facilities;

b) to maintain the safety and reliability of EPC's Electric Distribution System; or

c) for any other reason, including Emergencies, forced outages, potential overloading of EPC's Electric Distribution System or Force Majeure.

4.2 ISO System Control Requirements

The Customer or Retailer acknowledge and agree that EPC is bound by all ISO operating instructions, policies and procedures as are set forth in the current ISO rules and ISO operating policies and procedures; and they will cooperate to ensure EPC compliance with all ISO operating procedures, including, but not limited to, those procedures pertaining to minimum and maximum generation, Emergencies, and measures requiring involuntary Customer and Retailer participation, such as supply voltage reduction or full interruption of Customer Load by either manual or automatic means.

4.3 Compliance With Governmental Directives

The Customer and Retailer acknowledge that EPC may need to act in response to governmental or civil authority directives or regulatory orders, which may affect a Person's operations, and agree to cooperate with EPC in order to enable EPC compliance with all such directives or orders.

SECTION 5 LIABILITY AND INDEMNITY

5.1 EPC Liability

Notwithstanding any other provision of these Terms and Conditions or any provision of any agreement between EPC and a Customer or a Retailer relating to the provision of Electric Distribution Services (an “EPC Agreement”) EPC, its directors, officers, agents, employees and representatives (“EPC Parties”) shall not be liable to the Customer, its directors, officers, agents, employees and representatives (“Customer Parties”) for any loss, injury, damage, expense, charge, cost or liability of any kind suffered or incurred by the Customer Parties, or any of them, whether of a direct, indirect, special or consequential nature, howsoever or whensoever caused, and whether in any way caused by or resulting from the acts or omissions of the EPC Parties, or any of them, except for direct property damages incurred by the Customer as a direct result of a breach of these Terms and Conditions or applicable EPC Agreement or other act or omission by an EPC Party, which breach or other act or omission is caused by the negligence or willful act or omission of such EPC Party. Any liability under this Section will be limited to an amount in proportion to the degree to which the EPC Party acting negligently or wilfully is determined to be at fault. For the purpose of the foregoing and without otherwise restricting the generality thereof, “direct property damage” shall not include loss of revenue, loss of profits, loss of earnings, loss of production, loss of contract, cost of purchased or replacement capacity and energy, cost of capital, and loss of use of any facilities or property, or any other similar damage or loss whatsoever.

5.2 Release

Subject to Section 5.1 above, none of the EPC Parties will be liable to any of the Customer Parties for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by the Customer Parties or any of them, howsoever and whensoever caused, and each Customer Party hereby forever releases each of the EPC Parties from any liability or obligation in respect thereof.

5.3 Customer Liability

In addition to any other liability provisions set out in the Terms and Conditions or any provision in an EPC Agreement, a Customer Party (as defined above) shall be liable for any damages, costs, expenses, injuries, losses, or liabilities suffered or incurred by EPC Parties (as defined above), whether of a direct or indirect nature, caused by or arising from any acts or omissions of an Customer Party that result in a breach (“Breach”) of these Terms and Conditions or the applicable EPC Agreement, or any negligent or willful acts or omissions of a Customer Party outside of a Breach. Any liability under this section will be limited to an amount in proportion to the degree to which the Customer Party is at fault.

5.4 Interruption

EPC shall have the right, without any liability to Customers, Retailers, or any other Person in law, equity, contract or tort, to De-Energize or otherwise curtail, interrupt or reduce Electricity Services or any other service provided under these Terms and Conditions when:

a) EPC reasonably determines that such a De-Energization, curtailment, interruption or reduction is necessary:

    i) to facilitate the construction, installation, maintenance, repair, replacement or inspection of any of the Facilities,

    ii) to maintain the safety and reliability of EPC's Electric Distribution System, or a connecting entity's electrical system, or

    iii) due to any other reason, including Emergencies, forced outages, potential overloading of the Electric Distribution System or Force Majeure; or

b) EPC is directed to do so by the ISO.

EPC will make reasonable efforts to notify Customers of a De-Energization, curtailment or interruption or reduction in Distribution Access Service, although it is understood and agreed that there may be circumstances in which no notice may be given prior to any such De-Energization, curtailment, interruption or reduction.

EPC is not liable to Customers and Retailers or any other Person in law, equity, contract or tort for any loss, damage, injury or claim of any nature whatsoever arising from or connected in any way with:

a) A De-Energization, curtailment, interruption or reduction in Electricity Services or any other service provided under these Terms and Conditions; or

b) the sufficiency or lack of notice given by EPC of a De-Energization, curtailment, interruption or reduction in Electricity Services or any other service provided under these Terms and Conditions.

5.5 Force Majeure

5.5.1 Force Majeure Relief

If an event or circumstance of Force Majeure occurs that affects EPC's ability to provide any service under these Terms and Conditions, including Connection Services or other interconnection to its electric distribution system or Distribution Access Service, EPC's obligations and responsibilities hereunder and under any agreement relating to such services, so far as they are affected by the Force Majeure or the consequences thereof, shall be suspended until such Force Majeure or the consequences thereof are remedied and for such period thereafter as may reasonably be required to restore the services. All applicable charges in the EPC Distribution Tariff Rate Schedule, will continue to be payable during the period in which EPC claims relief by reason of Force Majeure.

5.5.2 Notice

EPC shall reasonably promptly give the relevant party notice of the Force Majeure including particulars hereof and shall promptly give the relevant party notice when the Force Majeure ceases to prevent performance of EPC's obligations.

5.5.3 Obligation to Remedy

EPC shall promptly remedy the cause and effect of the Force Majeure insofar as it is reasonably able to do so.

5.5.4 Strikes and Lockouts

Notwithstanding any other provision of these Terms and Conditions, the settlement of any strike, lockout or other industrial disturbance shall be wholly in the discretion of EPC and EPC may settle such strike, lockout or industrial disturbance at such time and on such Terms and Conditions as it may deem appropriate. No failure or delay in settling such strike, lockout or industrial disturbance shall constitute a cause or event within the control of EPC or deprive EPC of the benefits of this Section 5.6.

5.5.5 EPC Not Liable for Retailer

EPC provides Electricity Services under these Terms and Conditions. EPC also provides Retail Access Service, to Retailers, Connection Services, Transmission Connected Services and Distributed Generation Interconnection Services to Customers under these Terms and Conditions. Retailers and Customers may enter into an arrangement or agreement for the provision of services beyond those that EPC provides under these Terms and Conditions. EPC shall not be liable to a Customer or Retailer or other Person in law, equity, tort or contract for any loss, damage, injury or claim of any nature whatsoever.

SECTION 6 DISPUTE RESOLUTION

6.1 Arbitration Procedure

Unless otherwise specified herein, disputes arising between the Parties shall be determined by arbitration. With respect to any matters not specifically set out in these Terms and Conditions, the provisions of the *Arbitration Act* shall apply.

6.1.1 Decisions Binding

A decision of the single arbitrator or the majority of three arbitrators named or appointed shall be final and binding upon each of the Parties to the dispute. The Parties shall abide by the terms of any award rendered without delay.

6.2 Resolution by EPC and Customer or Retailer

Unless otherwise specified herein, any dispute arising between EPC and a Customer or Retailer in connection with these Terms and Conditions shall be resolved as set out in these Terms and Conditions. EPC and the Customer or Retailer, acting reasonably and in good faith, shall use their best efforts to resolve the dispute as soon as possible in an amicable manner. EPC, a Customer or Retailer may provide written notice of its desire to have the dispute resolved. Within 10 days of such notice being provided, EPC and the Customer or Retailer shall meet to attempt to resolve the dispute.

The costs of detailed analysis beyond the initial investigation will be borne by the requestor in the dispute, unless it is found that EPC is or was in error.

6.3 Resolution by Arbitration

If a dispute has not been resolved under Section 6.2 within 10 days after notice, from EPC, Customer or Retailer, of its desire to have the dispute resolved, then the dispute shall be resolved pursuant to the procedure set out in Section 6.4.

6.4 Arbitration Procedure

6.4.1 Arbitrators

Whenever any arbitration is permitted or required under these Terms and Conditions to resolve a dispute between the Parties, arbitration proceedings shall be commenced by a Party desiring arbitration (the “Initiating Party”) giving notice to the other Party (the “Responding Party”) specifying the matter to be arbitrated and requesting an arbitration thereof. The Initiating Party shall within five days thereafter, by written notice to the Responding Party, designate an arbitrator. The Responding Party shall, within five days after receiving notice from the Initiating Party, be entitled to appoint an arbitrator by written notice to the Initiating Party, and the two arbitrators so appointed shall thereupon meet and select a third arbitrator (the “Chairman”) acceptable to both. If the Responding Party fails to appoint an arbitrator within the time limit and deliver notice of the appointment to the Initiating Party, then the Initiating Party shall be entitled to appoint an arbitrator on behalf of the Responding Party and is hereby appointed the agent of the Responding Party for that purpose. In the event that the two arbitrators so appointed are unable to agree upon the Chairman within 10 days of the appointment of the arbitrator for the Responding Party, then the Initiating Party shall be entitled to make application to the Court of Queen's Bench of Alberta pursuant to the *Arbitration Act* for selection of the Chairman, and the provisions of the *Arbitration Act* shall govern such selection.

6.4.2 Failure to Concur

In the event of the failure, refusal or inability of any arbitrator to act, or continue to act, a new arbitrator shall be appointed in his stead, which appointment shall be made in the same manner as herein before provided.

6.4.3 Decision

The resultant arbitration panel shall thereupon proceed to hear the submissions of the Parties, and shall render a decision within 30 days after the appointment of the Chairman. The decision of the majority of the arbitration panel (or of the Chairman, if there is no majority decision) shall be deemed to be the decision of the arbitration panel and the decision of such majority or the Chairman, as the case may be, shall be final and binding upon the Parties and not subject to appeal. The arbitration panel shall have the authority to assess the costs of the arbitration panel against any Party, provided, however, that the Parties shall bear their own witness and counsel fees. The arbitrators shall have access to all books and records of the Parties relating to the matter in dispute and the Parties will co-operate with the arbitrators and provide all information reasonably requested by them.

6.4.4 Late Decision

If an arbitration decision is not made within the time herein provided, then until it is so made and unless the other Party has taken any of the actions referred to in this paragraph, a Party, upon 30 day's notice to the other Party and to the arbitrators, may:

a) cancel the appointment of the arbitrator previously made and initiate new arbitration proceedings by a new notice to the other Party pursuant to these Terms and Conditions; or

b) cancel such arbitration proceedings and proceed in the courts of the Province of Alberta as though Section 6.0 did not exist.

6.4.5 Technical Competence

Any arbitrator appointed under the provisions of Section 6.0 whether by concurrence of the Parties, by either Party, by the arbitrators, or by a Justice of the Court of Queen's Bench of Alberta, shall, in the reasonable opinion of the Person or Persons making such appointment, be possessed of such technical or other qualifications as may be reasonably necessary to enable him to properly adjudicate upon the dispute or difference.

6.4.6 Application of the *Arbitration Act*

Except as herein modified, the provisions of the *Arbitration Act* shall apply to any arbitration proceeding.

6.5 Continuity of Service

All performance required under these Terms and Conditions and payment therefore shall continue during the dispute resolution proceedings contemplated by these Terms and Conditions. However, in the case of any such proceedings pertaining to amounts payable under these Terms and Conditions, any payments or reimbursements required as a result of the proceedings shall be effective as of a date to be determined in such proceedings and interest shall be paid thereon by the Party required to make the payment or reimbursement on the amount thereof at the rate to be determined in the arbitration proceeding, from the date so determined, until paid.

SECTION 7 MISCELLANEOUS

7.1 Compliance with Applicable Legal Authorities

EPC and the Customer and Retailer are subject to, and shall comply with, all existing or future applicable federal, provincial and local laws, all existing or future orders or other actions of the ISO or of governmental authorities having applicable jurisdiction. EPC will not violate directly or indirectly, or become a Party to a violation of any requirement of the ISO or any applicable federal, provincial or local statute, regulation, bylaw, rule or order in order to provide any services. EPC's obligation to provide service under these Terms and Conditions is subject to the condition that all requisite governmental and regulatory approvals for the provision of such service will have been obtained and will be maintained in force during such period of service.

7.2 No Waiver

The failure of any Party to insist on any one or more instances upon strict performance of any provisions of these Terms and Conditions, or a Retail Access Services Agreement, or an Interconnection Agreement, or to take advantage of any of its rights hereunder, shall not be construed as a waiver of any such provisions or the relinquishment of any such right or any other right hereunder, which shall remain in full force and effect. No term or condition of these Terms and Conditions, a Retail Access Services Agreement or an Interconnection Agreement shall be deemed to have been waived and no breach excused unless such waiver or consent to excuse is in writing and signed by the Party claimed to have waived or consented to excuse.

7.3 No Assignment

A Customer or Retailer may not assign any rights or obligations under these Terms and Conditions without obtaining:

a) all necessary regulatory approval(s); and

b) the prior written consent of EPC, which consent shall not be unreasonably withheld.

EPC may assign any or all of its rights and obligations under these Terms and Conditions, the Retail Access Services Agreement, and the Interconnection Agreement, without the Customer's or Retailer's consent, to any entity provided the assignee agrees, in writing, to be bound by all of the Terms and Conditions hereof and provided all necessary regulatory approvals are obtained.

No assignment shall relieve the assigning Party of any of its obligations under these Terms and Conditions, the Retail Access Services Agreement, or the Interconnection Agreement, until such obligations have been assumed by the assignee in writing. Any assignment in violation of these Terms and Conditions shall be void.

SECTION 8 DEFAULT

8.1 Event of Default

A Party will be deemed to be in default ("Defaulting Party"), of its obligations under EPC's Distribution Tariff if it:

a) is the subject of a bankruptcy, insolvency or similar proceeding;

b) makes an assignment for the benefit of its creditors;

c) applies for, seeks consent to, or acquiesces in the appointment of a receiver, custodian, trustee, liquidator or similar official to manage all or a substantial portion of its assets;

d) violates any code, regulation or statute applicable to the supply of Energy; or

e) fails to pay the other Party ("Non-Defaulting Party"), when payment is due, maintain Retailer security requirements, or to satisfy any other obligation or requirement under EPC's Distribution Tariff, Retail Access Services Agreement, or the Interconnection Agreement, and fails to remedy any such failure or delinquency within three Business Days after receipt of written notice thereof from the Non-Defaulting Party.

8.2 Rights Upon Default

In an event of default, the Non-Defaulting Party shall be entitled to pursue any and all available legal and equitable remedies and terminate the Retail Access Services Agreement or Interconnection Agreement without any liability or responsibility whatsoever except for obligations arising prior to the date of termination, by written notice to the Defaulting Party, subject to any applicable regulatory requirements.

EPC may access security posted by a Party without prior notice, if the Party files a petition in bankruptcy (or equivalent, including the filing of an involuntary petition in bankruptcy against the Party), becomes a Defaulting Party or if for any reason a Party ceases to provide service to its Customers.

If a Party fails to make payment as set out in these Terms and Conditions, EPC may immediately withhold or suspend the Party's service, terminate service, transfer the Retailer's Customers to the Default Supplier, or the Regulated Rate Provider in the case of a Retailer, and apply any security held by EPC before the service coverage period of the security expires. Notwithstanding action provided for or taken pursuant to the preceding sentence, EPC may take credit action against any Party with respect to an account on which payment is not made to EPC. EPC may assess the Party for any or all administrative and collection costs relating to the recovery by EPC of amounts owed.

If a Party fails to provide or maintain adequate security upon EPC's request, EPC may immediately withhold or suspend services provided to the Party pursuant to these Terms and Conditions.

If a Party or Person who guarantees the financial obligations of the Party, as the case may be, ceases to be in EPC's estimation, creditworthy, EPC will demand alternative security and, if not provided, may immediately suspend the provision of further services to the Party until EPC in its sole discretion determines that the Party is capable of meeting its payment obligations by either satisfying the credit requirements or providing security.

Any withholding or suspension under these Terms and Conditions shall not relieve the Party from any obligation to pay any rate, charge or other amount payable which has accrued or is accruing to EPC.

PART B RETAIL ACCESS SERVICES

SECTION 9 RETAIL ACCESS SERVICES

9.1 Provision of Retail Access Services

EPC will offer Retail Access Services to Retailers who have demonstrated eligibility under EPC's eligibility requirements. EPC will provide Retail Access Services, upon and subject to these Terms and Conditions.

9.2 Reasonable Efforts

EPC shall use reasonable efforts to minimize any scheduled curtailment, interruption or reduction of Distribution Access Service to the extent reasonably practicable under the circumstances, and to resume Distribution Access Service as promptly as reasonably practicable.

9.3 De-Energization

9.3.1 De-Energization of a Site

EPC may De-Energize a Site, and thereby discontinue Distribution Access Service in respect of a Customer, as set out in these Terms and Conditions.

9.3.2 De-Energization at Request of Retailer

EPC will De-Energize a Site and discontinue Distribution Access Service in respect of a Customer, either temporarily or permanently, where the Retailer requests, on behalf of the Customer, physical disconnection of the service by submitting a request notice to EPC.

Only the Default Supplier, or the Regulated Rate Provider may request a De-Energization of a Customer’s Site for financial purposes.

A Retailer may request a Site to be De-Energized temporarily due to vacancy. If EPC finds the Site occupied, EPC reserves the right not to De-Energize immediately but to leave a warning notice in order to give the occupant(s) the opportunity to make appropriate arrangements for electricity service.

9.4 Re-Energization

After EPC receives a Re-Energize request from a Retailer, EPC will make arrangements with the Customer to Re-Energize the site. EPC will only Re-Energize the site at a time when either the electrical supply to the Site is off (i.e. circuit breaker is off) or the resident or owner of the site is present while the site is being Re-Energized.

9.5 Fees

EPC will charge fees to Retailers as outlined in the Fee Schedule.

SECTION 10 ARRANGEMENT FOR SYSTEM ACCESS SERVICES

EPC shall obtain from the ISO the System Access Service that EPC considers necessary to enable the transportation of Energy that will be sold or provided by the Customer’s Retailer. The Retailer shall be responsible for all related charges paid or payable by EPC to the ISO.

SECTION 11 METERING EQUIPMENT

EPC provides all Meter services within its service area. EPC is accredited by Measurement Canada to provide these services and will only install Measurement Canada approved metering equipment.

11.1 Provision of Meters

EPC will own, install, seal and approve the Meters for all Sites on its distribution system as set out in these Terms and Conditions. An Energy, Demand/Energy or interval Meter will be installed as required.

11.2 Provision of Interval Meters

An interval Meter will be installed at all new Sites with a planned installed capacity of 150 kVA or greater. EPC will replace a cumulative Meter with an interval Meter at an existing Site when the Demand registers greater than 150 kVA twice in a twelve month period or when modifications are made to the Electric Distribution System infrastructure to supply a Site with a capacity of 150 kVA or greater. In these cases, the cost of the new interval Meter will be borne by EPC. When the Customer changes at a Site, all Meters may be removed or modified at the sole discretion of EPC.

11.3 Unmetered Sites

Sites will be metered or unmetered at the sole discretion of EPC.

11.4 Meter Upgrades and Changes to Metering Equipment

Should a Customer or Retailer request:

a) an interval Meter when the Customer's capacity requirement is less than 150 kVA;

b) a communication device attached to an existing Meter, or;

c) an EPC approved non-standard Meter;

EPC shall provide, where practical, install, test and maintain the requested metering or communication device.

The Customer or Retailer shall bear the cost incurred by EPC in providing, installing and maintaining the Meter or communication device. Upon installation, or attachment, the Meter or communication device shall remain the property of EPC.

11.5 Hard to Access/Safety Concerns

EPC requires access and reserves the right to test and maintain the Meter on a Customer Site if:

a) EPC staff are prevented from meeting obligations as required by the AUC or the Electricity and Gas Inspection Regulation at locations that are inaccessible; or

b) in the judgment of EPC, there is an apparent and enduring safety concern present.

c) EPC will make reasonable efforts to set up an appointment and make arrangements for consistent access.

If unable to make contact and arrangements, EPC will De-Energize the Site and will not Re-Energize the Site until access has been obtained. The Customer shall bear the cost of the Re-Energization as set out in the Fee Schedule.

SECTION 12 METER DATA MANAGEMENT

12.1 Responsibilities

a) EPC shall be the sole source to manage consumption and interval data for interval and cumulative Meters to collect Meter data, to validate and estimate interval and cumulative Meter data, to store historical data, and to report data to the stakeholders as outlined in AUC *Rule 021*.

b) EPC will read all Meters in its service territory as set out in the EPC meter reading schedule.

12.2 Historical Data Request (Interval and Cumulative)

a) Any historical data request by any Person requesting the historical Meter data shall have authorization (written consent) by the Customer.

b) The MDM shall charge for any historical data request (interval and cumulative), including any special reports and graphs as outlined in the Fee Schedule.

c) Any Person requesting historical metering data from EPC shall fully complete EPC's "Authorization to Release Electricity Load Data" form.

d) The Customer's Retailer shall be responsible for obtaining necessary and appropriate contractual or other arrangements consistent with applicable statutes and regulations and these Terms and Conditions. EPC provides a standard service to Retailers in compliance with AUC *Rule 010*, Rule on Standards for Requesting and Exchanging Site-Specific Historic Usage Information for Retail Electricity.

12.3 Data Validation, Estimation and Editing

a) The MDM performs validation, estimation and editing as outlined in AUC *Rule 021* to produce settlement ready data for the LSA and Retailers.

b) If requested by the Customer's Retailer, EPC will describe methods used to estimate Customer Energy usage.

12.4 Meter Reading Disputes

It is the Retailer's responsibility to assist Customers concerned about their consumption levels and explain possible causes for their high consumption.

If a Retailer disputes a read, the Retailer may request an off-cycle read.

EPC will make a reasonable attempt to read any Meter as requested by the Retailer, subject to the charges set out in the Fee Schedule.

If an off-cycle read shows that a prior recorded reading is incorrect, then the cost of the off- cycle read will be waived.

12.5 Hard to Access Sites

Where EPC makes repeated attempts to read a Meter but is unable to obtain a Meter read at a Site, EPC will make reasonable efforts to contact the Customer.

Once contacted, the Customer must arrange an appointment to have the Meter read and make arrangements for consistent access or installation of a remote Meter device.

If unable to make contact and/or arrangements to regularly read the Meter at a residential or commercial property as dictated by the AUC, or due to Customer refusal to allow access or installation of a remote Meter device, or general inaccessibility of the Meter, EPC will De-Energize the Site and not Re-Energize the Site until access has been obtained. The Customer shall bear the cost of the Re-Energization as set out in the Fee Schedule.

SECTION 13 LOAD SETTLEMENT SERVICES

Load Settlement allocates Energy consumption to Retailers based on Customer enrollments as set out in AUC *Rule 021*.

13.1 Reporting/Posting Information

Load profiles, UFE, losses, loss multiplier and Settlement Zone consumption data will be made publicly available. Individual Retailers will have access only to their consumption data. Information reported will be consistent with AUC *Rule 021*.

AUC *Rule 021* calls for a number of standard content, standard format electronic transactions which EPC implements as described therein.

13.2 Fee for Service

Custom reports and other data may be provided to Retailers on request, on a fee for service basis as per the Fee Schedule. These reports and data may include detailed extracts of data that are used in settlement but not provided in the standard information complement as mandated in AUC *Rule 021*. The provision of reports and data requests are subject to Customer consent.

SECTION 14 SITE MANAGEMENT

14.1 General Retailer Responsibilities

Retailers must:

a) ensure that they have all requisite authorization before initiating any related transaction;

b) use the unique Site Identification Number as the primary means of communicating changes to Site status;

c) provide EPC with up-to-date basic Customer information (including emergency contact, account name, addresses and phone numbers) for all Sites that they service;

d) be responsible for all charges associated with a Site until the site is de-selected in accordance with AUC *Rule 021* or another Retailer enrolls that Site;

e) act as the point of contact with Customers; and

f) request Retail Electricity Services on behalf of Customers.

EPC expects to have limited direct contact with Customers who have Retailers. Therefore, the designated Retailer will be the main source of electricity industry information for these Customers. Calls from Customers regarding a power outage on the distribution system should be directed immediately to (403) 514-6100 (EPC's 24 hour trouble line).

(*Call 9-1-1 if the Customer is experiencing a life-threatening emergency.)

The Customer's Retailer shall be responsible for obtaining necessary and appropriate contractual or other arrangements consistent with applicable statutes and regulations and these Terms and Conditions.

The Customer's Retailer is financially responsible for all service requests made on behalf of their Customers. EPC will invoice Retailers for these services.

14.1.1 Retailer Due Diligence

It is the Retailer's responsibility to ensure valid Customer enrollment. Retailers are expected to have the required Customer enrollment authorization (i.e., the Retailer must confirm with the Customer that the Customer wishes to be enrolled and has explicitly given approval for the enrollment).

14.2 Compliance to AUC *Rule 021*

Enrollment, provision of Customer Information, Energize, De-Energize, Re-Energize, de-select, electronic information exchange and meter data management functions will be performed in accordance with AUC *Rule 021* as amended from time to time.

SECTION 15 INVOICING

15.1 Distribution Tariff Invoices

EPC will provide invoices to each Retailer as set out in the Distribution Tariff Rate Schedule and Fee Schedule. Distribution Tariff invoices from EPC are due as of the Invoice Date.

15.2 Billing to Customer

The Customer's Retailer will be responsible for any direct billing to and collections from the Customer.

15.3 Late Payment

Any invoice rendered to a Retailer for which valid payment has not been received as set out in these Terms and Conditions shall be considered past due. The penalty for late payment charges as set out in the Fee Schedule will be applicable to the total current charges outstanding. Payments will be applied first to arrears and then to current charges.

15.4 Default or Failure to Pay

Retailers who fail to make payments for Distribution Tariff services on time will be notified immediately. Failure to make full payment after notification may result in suspension of Retailer eligibility status as set out in these Terms and Conditions.

15.5 Estimated Invoices

EPC reserves the right to provide invoices based on estimated consumption.

15.6 Payment of Accounts

The Retailer shall pay the entire amount stated on the invoice without deduction, set-off or counterclaim, notwithstanding any dispute in whole or in part of the amount. Any invoice rendered to a Retailer is due on the Invoice Date. Invoices shall be deemed paid when payment is made either by way of cheque or electronic funds transfer to the bank account specified by EPC pursuant to the Retail Access Services Agreement. Payments received in foreign currency will be credited to the Retailer's account based on the foreign exchange dealer bid price that

EPC receives on the date the payment is deposited. Any dispute with respect to a Retailer's invoice shall be resolved by the dispute resolution processes.

Failure to receive an invoice does not release a Retailer from the obligation to pay the amount owing for any Retail Access Services provided by EPC with payment due dates as outlined in these Terms and Conditions.

15.6.1 No Payment Required

No payment, to a retailer shall be required on invoices or credit invoices on which the total amount due is less than $10.00.

15.6.2 Refunds

Refund cheques will be generated for credit invoice balances exceeding $10.00 and 30 days on Retailer's account.

15.7 Invoice Adjustments

Where EPC overcharges or undercharges a Retailer as a result of an invoicing error including, but not limited to, PFAM's incorrect Meter reads or clerical errors by an EPC representative applying the wrong rate, wrong billing factor, or an incorrect calculation, EPC may render an adjusted invoice for the amount of the undercharge, without interest, and shall issue a credit to the Retailer for the amount of the overcharge, without interest, as set out in the following procedures:

a) if a Retailer is found to have been overcharged due to an invoicing error, EPC will calculate the amount of the overcharge for credit to the Retailer on the Retailer's next invoice following the discovery of the invoicing error for those months during which an invoicing error occurred, up to a maximum period of 12 months immediately preceding the month in which the invoicing error is discovered, or as otherwise provided by any governmental authority, legislation or regulation. Overpayments will be offset against any invoices outstanding, unless a request to the contrary is received from the Retailer; and

b) if a Retailer is found to have been undercharged due to an invoicing error, EPC may invoice the Retailer for those months during which an invoicing error occurred, up to a maximum period of 12 months immediately preceding the month in which the invoicing error is discovered. Payment from the Retailer will be due as set out in these Terms and

Conditions.

15.7.1 Demand Waiver

EPC may consider granting a Demand waiver request when the new Demand is the result of an EPC power outage, which consequently requires the simultaneous start of the Customer's equipment. If the request is granted, the Billing Demand will be the higher of the Minimum Contract Demand or the Ratchet Demand. In addition, the peak Demand caused during the simultaneous start of the Customer's equipment will be excluded from the calculation of Ratchet Demand. A Demand waiver request must be provided, in writing, to EPC within 90 days of the power outage. Requests for a Demand waiver shall be directed to trac@enmax.com.

SECTION 16 ELIGIBILITY OF RETAILER

16.1 Eligibility of Retailer

Before EPC will provide Retail Access Services to a Retailer pursuant to these Terms and Conditions, a Retailer must meet and maintain the following eligibility requirements.

16.1.1 Licensing

The Retailer, to sell or provide Electricity Services, must be duly licensed and registered, where applicable, with Alberta Energy, Alberta Government Services, the ISO and subject to any regulations or policies made under the *Fair Trading Act* (Alberta).

16.1.2 Security Requirements

EPC's determination of the Retailer security requirements are as specified in the *Distribution Tariff Regulation* (Alberta).

16.1.3 Agreement between EPC and Retailer

The Retailer must have entered into a Retail Access Services Agreement with EPC, which is in full force and effect.

16.1.4 Communications Capabilities

Connectivity testing to ensure data exchange communications are established will be entered into only with prospective Retailers who have formally initiated the eligibility process described in these Terms and Conditions.

16.2 Confidentiality

EPC shall keep all Retailer specific credit and security information confidential unless EPC has the Retailer's written authorization and consent to disclose such information to other Parties, provided however that such information shall not be subject to such confidentiality where such information:

a) is generally available to the electric industry or the public at the time of disclosure;

b) subsequent to receipt by EPC, becomes generally available to the electrical industry or the public as a result of a disclosure by the Retailer or any Person authorized by the Retailer;

c) was available to EPC on a non-confidential basis prior to its disclosure to EPC;

d) subsequent to receipt by EPC, was on competent evidence established by EPC available to EPC on a non-confidential basis from a source other than the Retailer or an authorized representative of the Retailer, without breach of these Terms and Conditions; or

e) must be disclosed by law to a governmental authority where there is no reasonable alternative to such disclosure.

SECTION 17 CUSTOMER PROTECTION

17.1 Disclosure

Customers always have the right to access their information held by EPC. Any Retailer chosen by a Customer should have access to basic information held by EPC that is needed to serve the Customer and operate its business efficiently.

EPC will ensure that other Parties' access to Customer information is restricted unless the Customer consents to the disclosure of this information in a manner permitted under the ENMAX Corporation Code of Conduct compliance plan or the Code of Conduct Regulation (Alberta) provided however that such information shall not be considered confidential where:

a) the information is generally available to the public; or

b) must be disclosed by law to a governmental authority where there is no reasonable alternative to such disclosure.

Information may be transferred without consent in the case of legal, regulatory or law enforcement requirements.

17.2 Errors Discovered by Retailers

When a Retailer discovers that an error has been made in data it has transmitted to EPC, the Retailer shall correct the error and notify EPC immediately.

PART C CONNECTION SERVICES

SECTION 18 CONNECTION SERVICES

18.1 Provision of Connection Services

Upon request, EPC will provide Connection Services to Customers requesting such services and who meet the application requirements set out in these Terms and Conditions. EPC will make reasonable efforts to provide Connection Services that will allow for the supply of Energy to the Customer's facilities at a nominal 60-Hertz alternating current and at the nominal voltage level for the Service Connection and variations, which comply with the Canadian Standards Association standards. EPC shall make all reasonable efforts to provide a continuous supply of Energy to its Customers, but cannot guarantee an uninterrupted supply of Energy. Notwithstanding any other provision of these Terms and Conditions, in cases where the Connection Services are interrupted by defective equipment or fail from an event of Force Majeure, unless through the negligence of EPC's employees, servants or agents, EPC will not be liable for the defect, irregularity, interruption or failure.

Procedural and technical requirements that must be met prior to connecting facilities to the EPC Electric Distribution System:

a) within the Network boundary are described in the Network Servicing Policies and Guidelines; and

b) outside the Network boundary are described in the document entitled Requirements for Distribution Wires Access.

18.2 Application for Connection Services

A Customer may apply for Connection Services to allow for the supply of Energy as set out in these Terms and Conditions. Some voltage levels may not be available at all locations served by EPC's Electric Distribution System. Applications will be received through any agent or duly authorized representative of EPC. The Customer of record will be either:

a) the owner of the premises serviced; or

b) a tenant meeting credit requirements.

18.2.1 Method and Form of Application

If a Customer is not of the age of majority as defined in the *Age of Majority Act* (Alberta), a deposit may be required in order to obtain Connection Services. EPC reserves the right to verify the identity of the Customer and the accuracy of the information provided and to require the Customer to sign an application in writing on forms provided by EPC. No servant, agent or employee of EPC is authorized to modify orally any provisions of a written application or to bind EPC to any promise or representation contrary thereto. Modifications of written applications shall be in writing and duly executed by an authorized EPC representative.

18.2.2 Application by Retailer or Other Person

A Retailer or any other Person acting as agent of a Customer may apply for Connection Services on behalf of the Customer if the Retailer or other Person provides EPC with verifiable Customer authorization to make the application. The Customer authorization must be dated and signed by the Customer, and must include the Customer's name and explicit expression of the Customer's intention to obtain Connection Services at a specified Site.

18.2.3 Provision of Information

Upon request, EPC shall furnish to any Person detailed information on the method and manner of making application for Connection Services. Such information may include a copy of EPC's Requirements for Distribution Wires Access and Network Servicing Policies and Guidelines, a description of the Service Connections available, connections necessary between the Facilities and the Customer's facilities and premises, location of entrance Facilities and metering equipment, and Customer and EPC responsibilities for installation, operation and maintenance of the Facilities.

EPC may require an applicant for Connection Services to provide:

a) information regarding the location of the premises to be served (municipal address), the

Customer’s Connected Load (a single line diagram) and preferred supply conditions (interconnection requirements and a requested in-service date) and the manner in which Connection Services will be utilized;

b) site mechanical and final grading plans showing roads, driveways, sidewalks, building outlines, requested transformer location, final grade, landscaping, and gas and deep utility plans;

c) credit information or references;

d) any other information outlined in EPC’s Requirements for Distribution Wires Access and Network Servicing Policies and Guidelines, or that EPC reasonably requires; and

e) an estimate of usage per month, on a dollar basis.

Upon receipt of the required information, EPC will advise the applicant of the type and character of the Connection Services it will furnish to the Customer, (if any), any special conditions that must be satisfied before EPC will provide any Connection Services, the Site at which the Connection Services will be provided, the Customer’s Distribution Tariff Billing Demand and, if requested, the location of EPC's metering and related equipment.

18.2.4 Rejection of Application

EPC may, in its sole discretion, reject any applicant’s request for Connection Services where:

a) the type of Connection Services applied for are not available or normally provided by EPC in the area where the Connection Services are requested;

b) the applicant or the Customer does not have all requisite permits, certificates, licenses, or other authorizations or right-of-way agreements for the installation and operation of Connection Services;

c) EPC determines, that the Customer is not creditworthy or that a previous account held by the Customer with EPC is in arrears;

d) the Customer fails to provide an acceptable security deposit or letter of credit;

e) any representation made by the applicant or the Customer to EPC for the purpose of obtaining Connection Services is, in EPC’s opinion, fraudulent, untruthful or misleading;

f) the Customer has not, when requested by EPC, provided a signed written application for Connection Services;

g) the proposed Loads, in EPC’s opinion, have characteristics that might adversely affect the quality of service supplied to other Customers, the public safety, or the safety of EPC's personnel; or

h) outside the Network, a primary circuit (except for a primary metered service) is proposed to enter a Customer structure or where an EPC transformer is proposed to be within or on top of a Customer structure, or within any underground vault. Within the Network, circumstances where EPC may, in its sole discretion, reject any applicant’s request for Connection Services are detailed in Network Servicing Policies and Guidelines.

18.2.5 Approvals

The applicant for Connection Services shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations and right-of-way agreements necessary for the installation and operation of the Connection Services and shall submit copies of them to EPC upon request. EPC shall not be required to commence or continue installation or provision of Connection Services unless and until the applicant and the Customer have complied with the requirements of all governmental authorities, all permits, certificates, licenses, inspections, reports and other authorizations, and all right-of-way agreements, and all EPC requirements applicable to the installation and provision of Connection Services.

18.3 Responsibilities

18.3.1 Rights of Way

At the request of EPC, the Customer shall grant, or cause to be granted to EPC, without cost to EPC, such easements, rights-of-way and rights of entry over, upon or under the property owned, occupied or controlled by the Customer as EPC reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for Connection Services and the performance of all other obligations required to be performed by EPC hereunder.

In all agreements between the Customer and EPC regarding the management of vegetation, the Customer is required to give EPC permission to manage and remove vegetation on the property owned or controlled by the Customer and the right to maintain proper clearances as set out in the Alberta Electrical Utility Code. EPC will make reasonable efforts to notify the Customer before such work is performed.

The Customer shall not install or allow to be installed on property owned or controlled by the Customer any temporary or permanent structures that could interfere with the proper and safe operation of the Facilities or result in non-compliance with applicable statutes, regulations, standards and codes.

18.3.2 Customer Liability

For Customer owned equipment and facilities, the Customer assumes full responsibility for the proper use of Connection Services provided by EPC and for the condition, installation, suitability and safety of any and all wires, cables, devices or appurtenances or facilities Energized on the Customer's premises, or on premises owned, controlled or occupied by the Customer.

18.3.3 Protective Devices

The Customer shall be responsible for determining whether the Customer needs any devices to protect the Customer’s facilities from damage that may result from the use of Connection Services including, without limiting the generality of the foregoing, single phasing protection on three-phase Service Connections. The Customer shall provide, install, and maintain all such devices.

18.3.4 Standards for Interconnection

The Customer's installation shall conform to the requirements of EPC's Requirements for Distribution Wires Access or Network Servicing Policies and Guidelines and/or such further requirements as EPC may establish.

18.3.5 Suitability of Equipment

All of the Customer's facilities shall be suitable for operation with Connection Services and Facilities provided by EPC. The Customer shall not use Connection Services for any purpose, or with any apparatus, that could cause a power quality disturbance greater in magnitude than normal or acceptable industry limits, to any part of EPC's Electric Distribution System.

18.4 Connections

18.4.1 Interference with EPC’s Property

No one other than an authorized employee or agent of EPC shall be permitted to remove, operate, or maintain Meters, electric equipment or other Facilities. The Customer shall not interfere with, extend or alter EPC’s Meter, seals or other Facilities or permit the same to be done by anyone other than the authorized agents or employees of EPC. EPC property shall be installed at points most convenient for EPC's access and service and in conformance with applicable public regulations. The Customer shall be responsible for all destruction, loss or damage to EPC's Meters, electric equipment, seals or other Facilities located on the Customer’s premises or on premises owned, operated or controlled by the Customer where the destruction or damage is caused by a negligent act or omission or willful misconduct of the Customer or anyone permitted by the Customer to be on the premises, provided however, that the Customer shall not be liable for such destruction, loss or damage where such destruction, loss or damage is due to circumstances beyond the Customer's control.

18.4.2 Protection of EPC's Equipment

The Customer shall furnish and maintain, and arrange access to, at no cost to EPC, the necessary space, housing, fencing, barriers, and foundations for the protection of Facilities necessary for the provision of Connection Services to be installed upon the Customer's premises, or on the premises owned, occupied or controlled by the Customer, whether the Facilities are furnished by the Customer or by EPC. Such space, housing, fencing, barriers and foundations shall be in conformity with applicable laws and regulations and subject to EPC's specifications and approval. If the Customer refuses, EPC may at its option furnish and maintain, at the Customer's cost, the necessary protection.

18.4.3 Unauthorized Use or Unsafe Conditions

If EPC determines that there has been an unauthorized use of Energy or Connection Services including but not limited to any tampering with a Meter or other Facilities, unauthorized Energization or Re-Energization, or theft or fraud, intentional or unintentional use of Energy whereby EPC is denied full compensation for services provided, EPC may make such changes in its Meters, appliances, or other Facilities or take such other corrective action as may be appropriate to ensure only the authorized use of the Facilities and Connection Services, and also to ensure the safety of the general public and EPC personnel and the Customer is hereby deemed to consent to such corrective action. Upon finding an unauthorized or unsafe use of Facilities or Energy or finding that Connection Services have not been used as set out in these Terms and Conditions, EPC may discontinue the Connection Services and charge the Customer, Retailer or any other Person acting as agent for the Customer for all damages suffered by EPC and all costs incurred in correcting the condition. Nothing in this Section shall be deemed to constitute a waiver or limitation of legal recourse which may be open to EPC.

18.4.4 Relocation of Facilities

The costs of relocating EPC’s Meter, seals or other Facilities shall be borne by the Customer when done at the Customer's request, for the Customer's convenience, or if necessary to remedy any violation of law or regulation caused by the Customer. If requested by EPC, the Customer shall pay estimated relocation costs in advance.

18.4.5 Customer’s Facilities

For Customer owned facilities, the Customer will ensure that its facilities comply with the applicable requirements of the Canadian Electrical Code and with all technical EPC guidelines. The Customer shall not use its Connection Services in a manner which causes undue interference with any other Customer’s use of Connection Services such as an abnormal disturbance to the voltage, frequency and waveform of the Energy supply. At EPC’s request, the Customer shall, at the Customer’s expense, take whatever action is required to correct such interference or disturbance. Alternatively, EPC may elect to correct the interference or disturbance at the Customer’s expense.

The Customer shall design, install and operate its facilities in such a manner as to maintain a Power Factor of not less than 90%. EPC may require any Customer not satisfying this Power Factor requirement to furnish, install, and maintain, or EPC may install at the Customer’s cost, such remedial or corrective equipment as EPC may deem necessary under the circumstances.

The Customer shall not, without the written consent of EPC, use its own facilities in parallel operation with EPC’s Electric Distribution System. A Customer shall not extend or permit the extension of its facilities connected to EPC’s Electric Distribution System beyond property owned, controlled or occupied by that Customer.

18.4.6 New Multiple Dwellings

All units in new multi-unit residential buildings (including apartment and condominium buildings) will be metered and billed on an individual basis, unless EPC agrees otherwise.

Where EPC and a Customer have agreed that service to a new multiple dwelling shall be delivered through a single meter, the applicable commercial rate schedule will apply to the service.

18.5 Change in Connection Services

18.5.1 Prior Notice by Customer

A Customer shall give EPC reasonable written notice prior to any change in the Customer's requirements for Connection Services, including any change in Connected Load, to enable EPC to determine whether it can accommodate such change without alterations to its Facilities. A Retailer or any other Person who is acting as agent for a Customer and who provides EPC with verifiable authorization from the Customer may give such notice to EPC on the Customer's behalf. If EPC receives such notice from a Retailer or other Person, EPC may at its option require that such notice be provided directly from the Customer.

The Customer shall not change its requirement for Connection Services without EPC's written permission. The Customer shall be responsible for all damages, whether direct or indirect or consequential, caused to EPC's Electric Distribution System or Facilities as a result of the Customer changing its requirements for Connection Services without EPC's permission.

18.5.2 Changes to Facilities

If EPC must modify its Facilities to accommodate a specific request for change, howsoever caused, in a Customer's requirements for Connection Services, the Customer shall pay for all costs attributable to such modification including, without limitation, the following costs:

a) the estimated cost of removing the Facilities, less the estimated salvage value, plus

b) the estimated cost of installing the new Facilities, less

c) any applicable EPC investment in new Customer load, plus

d) prepaid operations and maintenance: 20% of the estimated costs of any Facilities that EPC deems to be Optional Facilities for the Customer. To be applied when EPC anticipates increased operation and maintenance expenses associated with the Customer's proposed facilities.

18.6 De-Energization of Service

18.6.1 De-Energization at Request of Customer

The Customer may on 30 day's prior oral or written notice to EPC, request the De-Energization of the Electricity Services. De-Energization notice can be revoked with at least 48 hours notice in advance of the scheduled De-Energization date. In the case of permanent De-Energization, the Customer may be required to pay for any unrecovered investment made by EPC in respect of providing the Customer's Electricity Services.

18.6.2 De-Energization for Safety Reasons

EPC reserves the right to discontinue Connection Services to a Site at any time without notice, or to refuse to make such Connection Services available to the Site, where, in EPC's opinion:

a) the Site has become hazardous;

b) the Site is unsafe or defective or will become unsafe or defective imminently;

c) there has been tampering with any service conductors, seals or any Facilities or any Meters;

d) the Site does not comply with applicable statutes, regulations, standards and codes and

EPC's requirements; or

e) the use of Connection Services may cause damage to the Facilities or EPC's Electric Distribution System or interfere with or otherwise disturb any other service provided by EPC.

EPC will continue Connection Services when the condition has been rectified to EPC's satisfaction, when the Customer has provided, or paid EPC's costs of providing, such Facilities as may be necessary to rectify the condition and prevent the condition from reoccurring, and the Customer's facilities are approved by the appropriate authority. EPC shall make a reasonable effort to notify each Customer, within a reasonable time after De-Energization, of the reason for the De-Energization and the actions required for Re-Energization.

18.6.3 De-Energization Other Than for Safety

EPC may at any time, after having given at least 48 hour's oral or written notice to a Customer, discontinue Connection Services or install a Load Limiting Device to restrict the capability of Connection Services if the Customer:

a) violates any provision of these Terms and Conditions or other components of the Distribution Tariff;

b) neglects due payment to the RRP or Default Supplier and the RRP or Default Supplier requests De-Energization. In this case, for residential Customers (rate class D100), EPC will install a Load Limiting Device, in accordance with the Distribution Tariff Regulation (Alberta);

c) upon receiving a written request to provide access to the Meter, neglects to arrange such access;

d) changes its requirements for Connection Services without the written permission of EPC; or

e) provides EPC with incorrect information or makes fraudulent or unauthorized use of Connection Services.

18.6.4 Re-Energization of Service Other Than for Safety

If Connection Services to a Customer are De-Energized or restricted by a Load Limiting Device the Customer shall, prior to Re-Energization of services:

a) pay any amount owing to EPC, the RRP or the Default Supplier (including any related restoration fees); and/or

b) resolve any non-financial reason for the De-Energization.

18.6.5 Removal of Facilities

Upon termination of Connection Services, EPC will be entitled to enter upon and remove from the property owned, occupied or controlled by the Customer any of the Facilities located upon the property.

18.7 Residential Investment Policy

18.7.1 Responsibilities:

EPC and the Developer will each be responsible for specific development costs as follows:

a) the EPC residential investment level will be the cost to provide modified underground residential distribution system (i.e., overhead main feeder) including the material cost associated with the service coil to standard subdivision developments as defined in Requirements for Distribution Wires Access;

b) the Customer shall be responsible for the installation and all future maintenance of the service coil on the Customer's property;

c) for non-standard subdivision and multi-family dwelling developments, the Developer shall pay the actual costs of construction including the service coil less the applicable EPC non-standard residential investment level;

d) for a total underground distribution system (i.e. underground main feeder), the Developer shall pay the actual cost of the underground feeder and associated equipment less EPC's allowance for an overhead feeder; and

e) EPC shall pay the costs of connecting a micro-generation generating unit to the interconnected electric system as set out in the Micro-Generation Regulation.

18.7.2 Conditions of Standard Subdivision Detached and Semi-Detached Dwelling Units

The EPC residential investment level is based on a standard detached and semi-detached dwelling units subdivision subject to the following conditions:

a) the average lot width shall be 23 metres or less;

b) an average of at least seven lots shall be serviced from each new transformer installed;

c) transformers which were installed previously to serve earlier portions of a subdivision shall be used where possible;

d) the distance from the nearest primary supply point to the first transformer divided by the number of lots shall be less than or equal to 12 metres per lot;

e) only 100 Amp and 200 Amp services are provided;

f) any portion of a subdivision involving re-lotting of previously serviced lots is excluded; and

g) there shall be at least 15 lots in any one development area.

Where development is other than detached or semi-detached dwelling units, or where the foregoing conditions for detached or semi-detached dwelling units are not met, the cost to the

Developer shall be the actual cost of construction less the applicable EPC non-standard residential investment level.

18.8 Non-Residential Investment Policy

For commercial services, EPC will invest in service connection(s) to a property or building as outlined in the Investment Schedule.

For commercial/industrial services, the following conditions shall apply:

a) Minimum Contract Demand: the minimum kVA contracted for by the Customer;

b) contract term: the term of the standard contract will be 15 years;

c) contract obligation: the contract applies to the original, contracted Customer;

d) contract “buy down”: Customers are permitted to “buy down” the EPC investment, and therefore reduce their Minimum Contract Demand, with a linear reduction factor over a 15 year time frame according to the following formula:

   Customer “buy down” cost = (original EPC investment – revised EPC investment) x (1-(contract years completed/15));

e) line contribution refunds: EPC does not currently employ this practice or endorse the refund of contribution-in-aid-of-construction from one Customer to another;

f) staged loading by Customer: standard investment levels will apply for Customers with staged loading subject to the full contract minimum being in place within two years of Energization, after which the 15 year contract period commences;

g) Optional Facilities: EPC’s investment will only apply to Facilities deemed reasonable, useful, and justifiable to EPC engineering staff. Facilities requested by a Customer that, in the opinion of EPC, are not reasonable, useful, or justifiable, shall be entirely at the cost of the Customer; and

h) transmission facilities: this policy does not in any way apply to or include transmission or substation related capital costs.

i) EPC shall pay the costs of connecting a micro-generation generating unit to the interconnected electric system as set out in the Micro-Generation Regulation. Distributed Generators with on-site generation having a minimum export capacity of 1,000 kVA will pay all costs related to obtaining Distributed Generation Interconnection Services.

SECTION 19 REVENUE METERING EQUIPMENT

19.1 Installation of Meters

19.1.1 Provision and Ownership

EPC shall provide, install and seal one or more Meters for the purpose of measuring the Energy delivered to a Customer. Each Meter shall remain the sole property of EPC regardless of the degree to which the Meter may be affixed to the Customer's premises, or to premises owned, occupied or controlled by the Customer or equipment.

Should a Customer who has a Demand less than 150 kVA request an interval Meter, EPC shall provide, install, test, and maintain the requested metering and communication device. The Customer shall bear the cost incurred by EPC in providing and installing the Meter or attaching the communication device per the Fee Schedule. Upon installation, the Meter or communication device shall remain the property of EPC and will be maintained by EPC.

19.1.2 Responsibility of Customer

Each Customer shall provide, own and install a Meter socket or Meter enclosure and other approved and required Facilities suitable for the installation of EPC's Meter as set out in EPC's current Requirements for Distribution Wires Access.

19.2 Installation of Metering Equipment

Installation of metering equipment shall be completed as set out in the requirements of the "Revenue Metering" Guide, which can be accessed through EPC's website.

19.3 Access to Metering Equipment

EPC may, at any reasonable time, read, inspect, remove and test its Meter installed on property owned or controlled by the Customer. EPC's employees, agents and other representatives shall have the right to enter property owned, occupied or controlled by a Customer at all reasonable times and intervals for the purpose of installing, maintaining, replacing, testing, monitoring, reading or removing EPC's electrical equipment and appliances or other Facilities or of discontinuing service or for any other purpose incidental to the provision of Connection Services and the Customer shall not prevent or hinder EPC's entry.

19.4 Changes to Metering

EPC may at any time change any Meter it installed.

Customer requests for a new Meter will be processed as per the Requirements for Distribution Wires Access.

SECTION 20 TRANSMISSION CONNECTED SERVICES

20.1 General

Transmission Connected Customers taking Transmission Connected Services from EPC will be subject to the provisions of the ISO approved tariff as it applies to EPC at the POD to which the Transmission Connected Customer's service is connected. This includes an application of all tariff amounts such as, but not limited to, contributions, riders, application fees, miscellaneous charges, study costs or ISO deferral account dispositions that are paid to or refunded by the ISO, as set out in the ISO's approved tariff.

20.2 System Access Service

EPC arranges for provision of System Access Service from the ISO for all Customers. The arrangements for System Access Service and the associated transmission Facilities for Transmission Connected Customers will be aligned with the Transmission Connected Customer's service requirements recognizing that the rates, terms and conditions of the ISO tariff will be applied directly to the Transmission Connected Customer.

EPC will commit to the ISO for commencement of the construction of new Facilities required for System Access Service for a Transmission Connected Customer after adequate credit arrangements, guarantees and commitment agreements, acceptable to EPC, are made with the Transmission Connected Customer.

The Transmission Connected Customer is required to sign an Interconnection Agreement with the transmission facility owner prior to a System Access Service agreement being executed.

20.3 Metering

The Meter of the Transmission Connected Customer is the Meter at the respective POD. Consequently, metering equipment shall be installed as set out in any ISO metering requirements. Any contribution associated with installation, changes or upgrades to metering to satisfy these requirements will be the responsibility of the Transmission Connected Customer.

20.4 Distribution Tariff

A Transmission Connected Customer will be invoiced as set out in the Distribution Tariff Rate Schedule.

20.5 Investment Policy

If a Customer contribution is required by the ISO for transmission Facilities to provide System Access Service to a Transmission Connected Customer, a charge for such contribution will apply directly to the Customer. Payment must be made as set out in the ISO tariff.

20.6 Changes to System Access Service

For any POD that is a Service Connection for a Transmission Connected Customer, EPC will make a request to the ISO for an increase or reduction in transmission contract levels or a change to the terms of System Access Service only upon written request from the Transmission Connected Customer.

Changes to a Transmission Connected Customer's contract levels or terms of System Access Service will be effective only upon agreement between EPC and the ISO.

The Customer will pay any costs and receive any refunds from the ISO that occur as a result of any such changes.

20.7 Exit Costs

If a service for a Transmission Connected Customer is terminated, the Customer shall pay all transmission related exit costs, which include:

a) any costs charged by the ISO to EPC, as a direct consequence of the Customer's termination of service;

b) the present value of any ongoing System Access Service costs for the particular POD that are attributable to the Customer and that will not be recovered by EPC from the Customer as a direct consequence of the Customer's termination of service;

c) any other un-recovered transmission related amounts as stipulated in the contract between EPC and the Customer; and

d) any outstanding amounts attributable to the Customer with respect to, but not limited to, any deferral accounts, rate riders or AUC decisions.

20.8 Approval to Connect Directly with ISO

As set out in Section 101(2) of the EUA, a Transmission Connected Customer may, with prior approval of EPC, enter into an arrangement directly with the ISO for the provision of System Access Service.

EPC will grant its approval under Section 101(2) only where the Transmission Connected Customer can demonstrate to EPC's satisfaction that System Access Service can be obtained by the Transmission Connected Customer from the ISO at a materially lower rate than is available to the Transmission Connected Customer from EPC, and where such rate differential results from:

a) charges levied by EPC for Distribution Access Service other than charges relating to the provision of metering and billing services;

b) the ability of the Transmission Connected Customer to capture a diversity benefit through the summation of System Access Service demand at two or more PODs where permitted by the ISO tariff; or

c) circumstances where the Transmission Connected Customer has obtained an industrial system designation pursuant to Section 4 of *the Hydro and Electric Energy Act* for the Site.

The following will not constitute a reduction in a Transmission Connected Customer's rate for System Access Service for purposes of this policy:

a) a reduction to or avoidance of any applicable Local Access Fee or similar charges made on behalf of the City of Calgary in respect of electricity consumed within the municipal boundaries unless otherwise approved by the City of Calgary; and

b) differences in the timing of charges or refunds for System Access Service to the Transmission Connected Customer.

Should EPC grant its approval under Section 101(2) of the EUA, EPC reserves the right to bill the

Transmission Connected Customer directly for all Local Access Fees and AUC approved riders and charges arising from services provided by EPC prior to the Transmission Connected Customer receiving System Access Service directly from the ISO pursuant to such a direct arrangement.

A request for entering into an arrangement directly with the ISO for the provision of System Access Service should be directed to the Vice President, Distribution at the EPC address identified in Section 3.12.

PART D DISTRIBUTED GENERATION SERVICES

SECTION 21 DISTRIBUTED GENERATION SERVICES

21.1 Micro-Generation Regulation

The Micro-Generation Regulation has been established under the EUA. EPC will comply with this Regulation and all associated rules and guidelines as established by the AUC.

21.2 Provision of Distributed Generation Interconnection Services

EPC will provide Distributed Generation Interconnection Services to Distributed Generators requesting such services who meet the application requirements set out in these Terms and Conditions. EPC will make reasonable efforts to provide Distributed Generation Interconnection Services that will allow for the supply of Energy from the Distributed Generator’s facilities, in a manner that does not degrade power quality, operability or reliability of the IES. Notwithstanding any other provision of these Terms and Conditions, in cases where the Distributed Generation Interconnection Services are interrupted by defective equipment or fail from an event of Force Majeure, unless through the negligence of EPC’s employees, servants, agents or contractors, EPC will not be liable for the defect, irregularity, interruption or failure.

Procedural and technical requirements that must be met prior to connecting facilities to the EPC Electric Distribution System are described:

a) in "Guide for Generator Interconnection to The Wires Owner Distribution System", "Guide for Micro-Generator Interconnection to the Wires Owner Distribution System", Requirements for Distribution Wires Access and Network Servicing Policies and Guidelines; or

b) for Micro-Generator facilities, in any applicable technical guidelines under the Micro-Generation Regulation.

These and related documents are, or will be, posted on the EPC or AUC websites, and can be obtained from EPC.

Both EPC and the Distributed Generator shall operate and maintain their respective facilities as set out in the ISO policies. The standards imposed by ISO may change and Parties are expected to comply with any changed standards upon receipt of notice or otherwise becoming aware of such changes.

21.3 Application for Distributed Generation Interconnection Services

A Distributed Generator may apply for Distributed Generation Interconnection Services to provide the delivery of Energy as set out in these Terms and Conditions.

21.3.1 Method and Form of Application

EPC reserves the right to verify the identity of the Distributed Generator and the accuracy of the information provided and to require the Distributed Generator to sign an application in writing on forms provided by, or acceptable to, EPC. No servant, agent or employee of EPC is authorized to modify orally any provisions of a written application or to bind EPC to any promise or representation contrary thereto. Modifications of written applications shall be in writing and duly executed by an authorized EPC representative.

21.3.2 Provision of Information

Upon request, EPC shall furnish detailed information on the method and manner of making application for Distributed Generation Interconnection Services. Such information may include copies of EPC's Distributed Generation interconnection guides, and Distributed Generator and EPC responsibilities for installation, operation and maintenance of Facilities.

EPC may require an applicant for Distributed Generation Interconnection Services to provide:

a) information regarding the location of the interconnection, service point address, the Distributed Generator's Connected Load, estimated Demand, preferred supply conditions, and the manner in which Distributed Generation Interconnection Services will be utilized;

b) credit information or references;

c) proof that the Distributed Generator has:

    i) obtained a system access authorization from the ISO, where required,

    ii) satisfied all membership and application requirements of the Power Pool, if selling to the Power Pool,

    iii) a mutual acceptance by the Distributed Generator and EPC of Operating Procedures, attached to and forming part of the Interconnection Agreement where applicable, and

    iv) had its facility commissioned and interconnected with EPC's circuits; and

d) any other information that EPC reasonably requires.

Upon receipt of the required information, EPC will advise the applicant of the type and character of the Distributed Generation Interconnection Services it will furnish to the Distributed Generator, if any, any special conditions that must be satisfied before EPC will provide any Distributed Generation Interconnection Services and, if requested, the location of EPC's metering and related equipment.

21.3.3 Rejection of Application

EPC may, in its sole discretion, reject any applicant’s request for Distributed Generation Interconnection Services where:

a) the type of Distributed Generation Interconnection Service applied for is not available;
b) the applicant or the Distributed Generator does not have requisite permits, certificates, licenses, or other authorizations or right-of-way agreements for the installation and operation of Distributed Generation Interconnection Services;
c) EPC determines that the Distributed Generator is not creditworthy or a previous account held by the Distributed Generator with EPC is in arrears;
d) the Distributed Generator fails to provide an acceptable security deposit or letter of credit;
e) any representation made by the applicant or the Distributed Generator to EPC for the purpose of obtaining Distributed Generation Interconnection Service is, in EPC’s opinion, fraudulent, untruthful or misleading;
f) the Distributed Generator has not, when requested by EPC, provided a signed written application for Distributed Generation Interconnection Services; or
g) the proposed interconnection, has characteristics that might adversely affect the quality of service supplied to other Distributed Generators, Customers, the public safety, or the safety of EPC's personnel.

21.3.4 Approvals

The applicant for Distributed Generation Interconnection Services shall be responsible for obtaining all permits, certificates, licenses, inspections, reports, and other authorizations and right-of-way agreements necessary for the installation and operation of the Distributed Generation and shall submit copies of them to EPC upon request. EPC shall not be required to commence or continue installation or provision of Distributed Generation Interconnection Services unless and until the applicant and the Generator have complied with the requirements of all governmental authorities, all permits, certificates, licenses, inspections, reports and other authorizations and all right-of-way agreements, and all EPC requirements applicable to the installation and provision of Distributed Generation Interconnection Services.

21.4 Responsibilities

21.4.1 Rights of Way

At the request of EPC, the Distributed Generator shall grant, or cause to be granted to EPC, without cost to EPC, such easements, rights-of-way and rights of entry over, upon or under the property owned, occupied or controlled by the Distributed Generator as EPC reasonably requires for the construction, installation, maintenance, repair and operation of the Facilities required for Distributed Generation service and the performance of all other obligations required to be performed by EPC hereunder.

The Distributed Generator shall provide access for EPC to the Distributed Generator's facility for the purposes of Meter reading or installation, maintenance or removal of the Facilities and for the purpose of treating, brushing, trimming and cutting of trees as is necessary for the proper operation of the Facilities.

The Distributed Generator shall not install or allow to be installed on property owned or controlled by the Distributed Generator any temporary or permanent structures that could interfere with the proper and safe operation of the Facilities or result in non-compliance with applicable statutes, regulations, standards and codes.

21.4.2 Distributed Generator Liability

The Distributed Generator assumes full responsibility for the proper use of Distributed Generation Interconnection Services provided by EPC and for the condition, installation, suitability and safety of any and all wires, cables, devices or appurtenances or Facilities Energized on the Distributed Generator’s premises or on premises owned, controlled or occupied by the Distributed Generator.

21.4.3 Protective Devices

The Distributed Generator shall be responsible for determining whether it requires any devices to protect its facilities from damage that may result from the use of Distributed Generation. The Distributed Generator shall be responsible for the design, supply, construction, operation and maintenance of all equipment on its side of the PCC necessary to provide protection to the Distributed Generator’s facilities.

21.4.4 Standards for Interconnection

The Distributed Generator’s installation shall conform to the requirements of EPC's Distributed Generation standards or such further requirements as EPC may establish from time to time. Copies of such requirements are available from EPC and will be posted on the EPC website.

21.4.5 Suitability of Equipment

All of the Distributed Generator’s facilities shall be suitable for operation with Distributed Generation Interconnection Services and Facilities provided by EPC. The Distributed Generator shall not use Distributed Generation for any purpose, or with any apparatus, that would cause an adverse disturbance to any part of EPC's Electric Distribution System. EPC has the right, but not the obligation, to inspect the Distributed Generator’s facility. This right of inspection shall not relieve the Distributed Generator of responsibility for the safe design, construction, maintenance and operation of its facility and all liability in connection therewith remains with the Distributed Generator. The Distributed Generator shall provide reasonable access upon reasonable prior notice to enable EPC to conduct such inspection.

21.5 Connections

21.5.1 Interconnection Charges

The Distributed Generator shall pay EPC an amount, as determined by the Non-Residential Investment Policy set out in these Terms and Conditions, for the interconnection of the Facilities to the Distributed Generator's facility. The cost of interconnection shall include, but not be limited to, costs incurred in the design, supply, construction, operation and maintenance of all interconnection, protective and metering equipment, including the costs of any modifications to the Facilities that may be required.

21.5.2 Interference with EPC's Property

No one other than an authorized employee or agent of EPC shall be permitted to remove, operate, or maintain Meters, electric equipment or other Facilities. The Distributed Generator shall not interfere with, extend or alter EPC's Meter, seals or other Facilities or permit the same to be done by anyone other than the authorized agents or employees of EPC. EPC property shall be installed at points most convenient for EPC's access and service and in conformance with applicable public regulations. The Distributed Generator shall be responsible for all destruction, loss or damage to EPC's Meters, electric equipment, seals or other Facilities located on the Distributed Generator's premises or on premises owned, operated or controlled by the Distributed Generator where the destruction or damage is caused by a negligent act or omission or willful misconduct of the Distributed Generator or anyone permitted by them to be on the premises, provided however, that the Distributed Generator shall not be liable for such destruction, loss or damage where such destruction, loss or damage is due to circumstances beyond the Distributed Generator's control.

21.5.3 Protection of EPC's Equipment

The Distributed Generator shall furnish and maintain, at no cost to EPC, the necessary space, housing, fencing, barriers, and foundations for the protection of Facilities necessary for the provision of Distributed Generation Interconnection Services to be installed upon the Distributed Generator's premises, or on the premises owned, occupied or controlled by the Distributed Generator, whether the Facilities are furnished by the Distributed Generator or by EPC. If the Distributed Generator refuses, EPC may at its option at the Distributed Generator's cost, furnish and maintain, the necessary protection. Such space, housing, fencing, barriers and foundations shall be in conformity with applicable laws and regulations and subject to EPC's specifications and approval.

21.5.4 Unauthorized Use or Unsafe Conditions

If EPC determines that there has been an unauthorized use of Distributed Generation Interconnection Services including but not limited to any tampering with a Meter or other Facilities, unauthorized connection or reconnection, or theft or fraud, whereby EPC is denied full compensation for services provided, EPC may make such changes in its Meters, appliances, or other Facilities or take such other corrective action as may be appropriate to ensure only the authorized use of Distributed Generation Interconnection Services, and also to ensure the safety of the general public and EPC personnel, and the Distributed Generator is hereby deemed to consent to such corrective action. Upon finding an unauthorized use of Facilities or finding that Distributed Generation Interconnection Services have not been used as set out in these Terms and Conditions, EPC may discontinue the Distributed Generation Interconnection Services and charge the Distributed Generator all damages suffered by EPC and all costs incurred in correcting the condition. Nothing in this Section shall be deemed to constitute a waiver or limitation of any other legal recourse, which may be open to EPC.

21.5.5 Relocation of Facilities

The costs of relocating EPC's Meter, seals or other Facilities shall be borne by the Distributed Generator when done at its request, for its convenience, or if necessary to remedy any violation of law or regulation caused by the Distributed Generator. If requested by EPC, the Distributed Generator shall pay estimated relocation costs in advance.

21.5.6 Distributed Generator's Facilities

The Distributed Generator shall operate and maintain its facilities in compliance with the EPC "Guide for Generator Interconnection to the Wires Owner Distribution System" and the "Guide for Micro-Generator Interconnection to the Wires Owner Distribution System", which are posted on the EPC website. Additionally, any applicable technical guidelines under the Micro- Generation Regulation must be observed.

21.5.7 Prior Notice by Distributed Generator

A Distributed Generator shall give EPC reasonable written notice prior to any change in the Distributed Generator's requirements for Distributed Generation Interconnection Services, including any change in generation, to enable EPC to determine whether it can accommodate such change without alterations to its Facilities.

The Distributed Generator shall not change its requirement for Distributed Generation Interconnection Services without EPC's written permission which shall not be unreasonably withheld. The Distributed Generator shall be responsible for all damages, whether direct or indirect or consequential, caused to EPC's Electric Distribution System or Facilities as a result of the Distributed Generator changing its requirements for Distributed Generation Interconnection Services without EPC's permission.

21.5.8 Changes to Facilities

If EPC must modify its Facilities to accommodate a change in a Distributed Generator's requirements for Distributed Generation Interconnection Services, the Distributed Generator shall pay for all costs attributable to such modification including, without limitation, the following costs:

a) the estimated cost of removing the Facilities, less the estimated salvage value, plus

b) the estimated cost of installing the new Facilities, less

c) any applicable EPC investment in new Customer load, plus

d) prepaid operations and maintenance: 20% of the estimated costs of any Facilities that EPC deems to be Optional Facilities for the Customer. To be applied when EPC anticipates increased operation and maintenance expenses associated with the Customer's proposed facilities.

21.6 De-Energization of Service

21.6.1 De-Energization at Request of Distributed Generator

The Distributed Generator may on 30 days prior oral or written notice to EPC, request the De-Energization or reduction in capability of its Distributed Generation. De-Energization notice can be revoked with at least 48 hours notice in advance of the scheduled De-Energization date. In the case of permanent De-Energization, the Distributed Generator may be required to pay for any unrecovered investment made by EPC in respect of the Distributed Generator's service.

21.6.2 De-Energization for Safety Reasons

EPC reserves the right to De-Energize Distributed Generation Interconnection Services to a Distributed Generator at any time without notice, or to refuse to make such services available to the Distributed Generator, where, in EPC's opinion:

a) the Distributed Generator has permitted its facilities to become hazardous;

b) the Distributed Generator's facilities are unsafe or defective or will become unsafe or defective imminently;

c) there has been tampering with any service conductors, seals or any Facilities or any Meters;

d) the Distributed Generator's facilities fail to comply with applicable statutes, regulations, standards, codes and EPC's generator interconnection requirements; or

e) the use of Distributed Generation Interconnection Services may cause damage to the Facilities or EPC's Electric Distribution System or interfere with or otherwise adversely affect any other service provided by EPC.

EPC will Re-Energize Distributed Generation Interconnection Services when the condition has been rectified to EPC's satisfaction, when the Distributed Generator has provided, or paid EPC's costs of providing, such Facilities as may be necessary to rectify the condition and prevent the condition from reoccurring, and the Distributed Generator's facilities are approved by the appropriate authority. EPC shall make a reasonable effort to notify each Distributed Generator within a reasonable time after De-Energization, of the reason for the De-Energization and the actions required for Re-Energization.

21.6.3 De-Energization Other Than for Safety

EPC may at any time, after having given at least 48 hour's prior oral or written notice to a Distributed Generator, discontinue Distributed Generation Interconnection Services to the Distributed Generator, if it:

a) violates any provision of the Distribution Tariff;

b) neglects or refuses to pay when due, all amounts required to be paid under the Distribution Tariff;

c) changes its requirements for Distributed Generation Interconnection Services without the written permission of EPC, which will not be unreasonably withheld; or

d) provides EPC with incorrect information or makes fraudulent or unauthorized use of Distributed Generation Interconnection Services.

21.6.4 Re-Energization of Service Other Than for Safety

If Distributed Generation Interconnection Services to a Distributed Generator are De-Energized, the Distributed Generator shall, prior to EPC Re-Energization of Distributed Generation Interconnection Services:

a) pay any amount owing to EPC (including any related restoration fees); and/or

b) resolve any non-financial reason for the De-Energization.

21.6.5 Removal of Facilities

Upon termination of Distributed Generation Interconnection Services, EPC will be entitled to enter upon and remove from the property owned, occupied or controlled by the Distributed Generator or any of the Facilities located upon the property.

21.6.6 Fee Schedule

EPC reserves the right to impose reasonable fees and charges pursuant to the various provisions of these Terms and Conditions. The fees are set out in the Fee Schedule.

SECTION 22 METERING EQUIPMENT

22.1 Installation of Meters

22.1.1 Provision and Ownership

EPC shall provide, install and seal one or more Meters for the purpose of measuring the Energy received from a Distributed Generator.

Each Meter shall remain the sole property of EPC regardless of the degree to which the Meter may be affixed to the Distributed Generator's premises, or to premises owned, occupied or controlled by the Distributed Generator, or equipment.

22.1.2 Distributed Generator Meters

The Distributed Generator retains ownership of any Distributed Generator owned Meter on its side of the point of service connection that it has installed. The selection of Meters, calibration of Meters and handling of Meter disputes shall be as set out in the *Electricity and Gas Inspection Act* (Canada). EPC may arrange with the Distributed Generator to have Distributed Generation metering equipment tested or calibrated by the proper official designated by the *Electricity and Gas Inspection Act* (Canada).

22.2 Location

Meter locations shall be designated by EPC based on the particulars of the Distributed Generation requested and convenience of access to the Meter. Where a Meter is installed on a Distributed Generator owned pole, the pole shall be provided and maintained by the Distributed Generator as required by the Canadian Electrical Code and any other applicable statutes, regulations, standards and codes.

22.3 Access to Metering Equipment

EPC may, at any reasonable time, read, inspect, remove and test its Meter installed on property owned or controlled by the Distributed Generator. EPC's employees, agents and other representatives shall have the right to enter property owned, occupied or controlled by a Distributed Generator at all reasonable times and intervals for the purpose of installing, maintaining, replacing, testing, monitoring, reading or removing EPC's electrical equipment and appliances or other Facilities or of discontinuing service or for any other purpose incidental to the provision of Distributed Generation Interconnection Services, and the Distributed Generator shall not prevent or hinder EPC's entry.

22.4 Changes to Metering

EPC may at any time change any Meter it installed.

Distributed Generator requests for a new Meter will be processed as per the Requirements for Distribution Wires Access.

SECTION 23 MISCELLANEOUS

23.1 Insurance

Except as otherwise expressly provided in the Interconnection Agreement with the Distributed Generator, the Distributed Generator shall purchase a liability insurance program for the operation of the generator that a prudent operator of a similar generator would maintain. The cost of obtaining and maintaining such liability insurance shall be borne by the Distributed Generator.

Except as otherwise expressly provided in the Interconnection Agreement with the Distributed Generator, in respect of the insurance policies carried by the Distributed Generator under this Section of these Terms and Conditions, each insurance policy shall, include waivers of subrogation in favour of EPC and any commercial general liability policy shall include a cross liability and blanket contractual clause and shall include EPC as an additional insured. The Distributed Generator will provide a certificate of insurance in this regard to EPC.

ENMAX POWER CORPORATION

DISTRIBUTION TARIFF

Terms and Conditions
Investment Schedule

Effective January 1, 2021

For commercial services, EPC will invest in service connection(s) to a property or building as outlined below:

Customer Type	EPC Investment Policy (New Load)
Small Commercial (Rate Code D200), Streetlights (Rate Code D500)	$12,940/Site
Medium Commercial – (Rate Code D300), Large Commercial – Secondary (Rate Code D310)	$12,940/Site (no Minimum Contract Demand required), or; $324/kVA of Minimum Contract Demand up to eighty percent (80%) of anticipated maximum Demand (Minimum Contract Demand in Network area is estimated)
Large Commercial – Primary (Rate Code D410)	$12,940/Site (no Minimum Contract Demand required), or; $96/ kVA of Minimum Contract Demand up to eighty percent (80%) of anticipated maximum Demand (Minimum Contract Demand in Network area is estimated
Overhead and Underground Commercial Subdivision	$7,765/lot (not applicable in Network area)
Irrigation Services (Controls), Temporary Services (includes Sign Services)	Not applicable

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Investment Schedule and apply to all Electricity Services supplied under this Tariff.

ENMAX POWER CORPORATION

DISTRIBUTION TARIFF

Terms and Conditions
Fee Schedule

Effective January 1, 2021

The fees contained in this Schedule are non-refundable and are charged in all circumstances.

They apply to the services described in the EPC Distribution Tariff Terms and Conditions.

1. Temporary De-Energize **$51.00 per request**

This fee applies to a Retailer who requests a temporary De-Energization of service. EPC may choose to install a load limiting device due to seasonal, safety or other reasons. The fee is charged to the requesting Retailer.

2. Re-Energize after Temporary De-Energize **$51.00 per request**

This fee applies to a Retailer who requests a Re-Energization of service including the removal of a Load Limiting device. The fee is charged to the requesting Retailer.

3. Urgent Reconnect **$130.00 per request**

This fee applies when a Retailer requests an Urgent, Priority Code 1 Reconnect (Re-Energization) including the removal of a load limiter. The fee is charged to the requesting Retailer.

4. Permanent De-Energize **No charge**

This fee applies to Sites where the Site is De-Energized and the equipment permanently removed. The fee is charged to the requesting Retailer.

5. Financial De-Energize **$51.00 per request**

This fee applies to a De-Energize request from the Default Supplier or Regulated Rate Supplier due to non-payment of a Customer account. EPC may choose to install a load limiting device due to seasonal, safety or other reasons. This fee also applies to a request from the Default Supplier or Regulated Rate Provider to remove a Load Limiting Device and fully De-Energize the Site. The fee is charged to the requesting Retailer.

6. Re-Energize after Financial De-Energize **$51.00 per request**

This fee applies to a Re-Energize request from a Retailer for a Site that was fully De-Energized or a load limiting devise installed for financial reasons. The fee is charged to the requesting Retailer.

7. Delivery of Cut-Off Warning Notice **$51.00 per notice**

This fee applies to a request from a Retailer to deliver a cut-off warning notice at a Site where either the Site will be cut-off for financial reasons or the Customer needs to be warned of impending cut-off due to vacancy. The fee is charged to the requesting Retailer.

8. Extra Service Trip **$80.00 per trip**

This fee applies when an extra service trip(s) to a Customer's Site is required, after the initial Energization request failed as a result of deficiencies related to Customer facilities, unsafe conditions or non-compliance with codes and Revenue Metering Guidelines. The fee(s) is charged to the Retailer who has enrolled the site.

9. Meter Field In Situ Test **$202.00 for Self Contained Meter**
$259.00 for Instrument-type Meter

This fee applies when EPC tests a Meter at the request of a Retailer or Customer. The fee is charged only if the accuracy of the Meter is found to be within the limits allowed by Measurement Canada. The fee is charged to the Retailer that enrolled the site, where applicable.

10. Off-Cycle Meter Reading **$53.00 per request**

This fee is applied when a Retailer requests that an off-cycle Meter reading be performed. The fee is charged to the requesting Retailer.

11. Interval Data Request - HUF Format **$0.00 per Site – per request**

This fee applies when a Retailer or another party authorized by the Customer requests interval Meter data for a period of no more than 425 calendar days from date of request. This fee is limited to one annual request per site by either Retailer or any other party authorized by the Customer. Additional requests made during the subsequent 12 months are considered special reports and subject to an additional fee, unless waived by EPC, as specified in this Fee Schedule.

12. Cumulative Data Request, HUF Format **$0.00 per Site – per request**

This fee applies when a Retailer or another party authorized by the Customer requests cumulative Meter data for a period of no more than 425 calendar days from date of request. This fee is limited to one annual request per site by either Retailer or any other party authorized by the Customer. Additional requests made during the subsequent 12 months are considered special reports and subject to an additional fee, unless waived by EPC, as specified in this Fee Schedule.

13. Non-Standard Interval Data Request **$121.00 per hour**

This fee is applied when a request is made for interval data this not provided in HUF format. These requests will be billed in hourly increments, with a minimum one hour charge.

14. Non-standard Data Request - All Other Requests **$121.00 per hour**

This fee is applied when a request is made for non-interval data this not provided in HUF format. These requests will be billed in hourly increments, with a minimum one hour charge.

15. Customer Requests – Off Hours **$310.00 per hour**

This fee applies when work is scheduled at the request of either the customer or EPC. A customer that requires work to be scheduled outside of EPC's normal business hours (Monday to Friday, 8:00 a.m. to 5:00 p.m.)[1] will be required to pay this fee.

[1] As defined in Article 13 of the Collective Agreement between ENMAX Corporation & IBEW Local 254

16. Dishonoured Payments **$22.00**

This fee applies to all dishonoured cheques or other payment dishonoured, rejected or reversed by any financial institution for any reason.

17. Meter Upgrade **$113.00 per hour for one person/one truck (single phase)**
$228.00 per hour for two people/one truck (multi phase)

This fee applies for the time associated with Meter upgrades. The Customer is also responsible for the cost of materials including the Meter.

18. Penalty for Late Payment **3.41% of the total current charges**

This fee applies to Retailers or Customers. A one-time penalty charge of 3.41% will be applied no less than 25 days following the current Invoice Date indicated on the bill to total current charges outstanding.

TERMS AND CONDITIONS

The Terms and Conditions of the EPC Distribution Tariff form part of this Fee Schedule and apply to all Electricity Services supplied under this Tariff.