Alberta Utilities Commission

Direct Energy Regulated Services

2020-2022 Default Rate Tariff and Regulated Rate Tariff – Negotiated Settlement Agreement

June 4, 2021

Alberta Utilities Commission
Decision 26207-D01-2021
Direct Energy Regulated Services
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Proceeding 26207

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1 Decision summary

1. In this decision, the Alberta Utilities Commission approves an application from Direct Energy Regulated Services (DERS) requesting approval of a negotiated settlement agreement (NSA) reached with respect to its 2020-2022 default rate tariff (DRT) and regulated rate tariff (RRT) application.

2. In addition, the Commission makes findings concerning DERS' compliance with directions given in Decision 24237-D01-2019[1] and the true-up of its interim rates.

2 Background

3. DERS is a business unit of Direct Energy Marketing Limited and performs the natural gas DRT and electricity RRT functions in the service territories of ATCO Gas and Pipelines Ltd. (ATCO Gas) and ATCO Electric Ltd., respectively.

4. On December 21, 2020, DERS filed an application with the Commission requesting approval of its DRT and RRT revenue requirements and associated rates for 2020-2022.

5. The Commission issued a notice of the application on December 22, 2020 and received submissions from the Consumers' Coalition of Alberta (CCA) and the Office of the Utilities Consumer Advocate (UCA) on January 8, 2021.

6. On January 29, 2021, the chair of the Commission directed parties to proceed to mediation in an effort to reach a settlement of the application. Mr. Jack Marshall, QC, and Mr. Doug Crowther, QC, were appointed as co-mediators. The Commission directed mediation to commence on February 1, 2021, and to conclude no later than April 1, 2021.

7. Information requests (IRs) from the CCA and the UCA to DERS and the responses that arose during the mediated settlement discussions were filed on the public record of the proceeding. The mediation process, including the deadlines for IRs and responses, was established by the mediators as part of the mediated settlement process. Offers and counter-offers during the negotiations were confidential to the parties and the mediators involved in mediation.

8. On April 1, 2021, DERS advised the Commission that a verbal agreement was reached and that it required more time to prepare the settlement materials. The Commission directed DERS to file all settlement materials by April 23, 2021.[2]

[1] Decision 24237-D01-2019: Direct Energy Regulated Services, 2019 Default Rate Tariff and Regulated Rate Tariff, Proceeding 24237, December 5, 2019.
[2] Exhibit 26207-X0107, Mediation Update and Proposed Schedule, PDF page 1.

9. On April 23, 2021, DERS filed the NSA. The NSA consisted of a signed agreement between the parties and six appendixes to the signed agreement. On May 4, 2021, the Commission issued IRs to DERS related to the NSA, which DERS responded to on May 5, 2021.

10. The Commission considers that the close of record for this proceeding was May 5, 2021.

11. In reaching the determinations set out within this decision, the Commission has considered all relevant materials on the record of this proceeding. 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 that matter.

3 Statutory and rule requirements for approval of a negotiated settlement agreement

12. Section 132(1)(a) of the *Electric Utilities Act* authorizes the Commission to establish rules, practices and procedures that facilitate negotiated settlements. Pursuant to this authority, the Commission has established Rule 018: *Rules on Negotiated Settlements*.

13. Rule 018 outlines several requirements associated with negotiated settlements including filing sufficient material in any settlement agreement to allow the Commission to assess its effect on rates and services. The applicant bears the onus of demonstrating that there is sufficient evidence to support its application for approval of the settlement.[3]

14. Section 8 of Rule 018 requires that the Commission assess whether the settlement results in rates as well as terms and conditions that are just and reasonable, and intervene if it determines that a unanimous settlement is patently against the public interest or contrary to law.

15. DERS applied for approval of the NSA in its entirety.[4] Section 134 of the *Electric Utilities Act* and Section 28.53 of the *Gas Utilities Act* give the Commission the authority to approve or refuse negotiated settlements. Section 135 of the *Electric Utilities Act* and Section 28.6 of the *Gas Utilities Act* requires the Commission to either approve the entire settlement, or refuse it, if the settlement is contingent on the Commission accepting the entire settlement, as it is in this case.

16. The Court of Appeal of Alberta in *ATCO Electric Limited v Alberta (Energy and Utilities Board)* provided guidance with respect to the Alberta Energy and Utilities Board's (the Commission's predecessor (the board)) obligations in considering settlement agreements. The court stated that the ultimate responsibility for approving negotiated settlements and ensuring that the process is fair and reasonable rests with the independent body. The court further stated that the negotiated settlement process (NSP) does not replace an appropriate and informed review by the board as to what is in the overall public interest. The court confirmed that the board's discretion in controlling rates as mandated by statute cannot be fettered by a negotiated settlement.[5]

3 Rule 018, sections 4 and 6.
4 Exhibit 26207-X0109, Section 2.3.
5 *ATCO Electric Limited v Alberta (Energy and Utilities Board)*, 2004 ABCA 215, paragraphs 138-139.

17. The Court of Appeal defined the public interest to be considered in the context of assessing whether to approve a negotiated settlement that is (i) presented as a package deal and approved as such, or (ii) approved in its entirety by the board, even if the settlement is not presented as a package deal. In both events, the board's consideration of the public interest is restricted to ratepayers, and not the utility's interests, in deciding whether to approve the negotiated settlement. However, in other circumstances, such as where the board alters or proposes to alter the terms and conditions of a negotiated settlement, then the board's consideration of the public interest will necessarily include the utility's economic interests along with ratepayers.[6]

18. Given the above guidance and Section 8 of Rule 018, the Commission considers that, in the current proceeding, it must accept or reject the NSA in its entirety and, in so doing, must consider the fairness and public interest factors with the objectives of determining:

(i) if the process resulting in the settlement was fair, and

(ii) if approval of the settlement will lead to rates that are just and reasonable. In making this determination, the Commission will consider if the settlement is patently contrary to the public interest or contrary to law.

4 Commission evaluation of the negotiated settlement agreement

19. DERS submitted that the unanimously agreed-upon NSA would result in just and reasonable rates because it reflects a number of trade-offs and concessions that collectively meet the interests of the parties.[7]

4.1 Fairness of the negotiated settlement process

20. The first question is whether the process that resulted in the NSA was fair. The Commission reviewed the material filed by DERS regarding the details of the NSP and, for the reasons provided below, is satisfied that the NSP was fair. In order to demonstrate that an NSP is fair, the Commission must be satisfied that proper notice was given, that relevant information has been disclosed, and that parties were able to have meaningful participation.

21. Section 3 of Rule 018 requires a statement in the settlement agreement confirming that proper notice was provided by the applicant to all interested parties. Notice must be provided under the Commission's *Rules of Practice* (Rule 001). Section 4.1 of the NSA confirms that proper notice was provided to all interested parties by way of AUC correspondence on the eFiling System[8] and with the filing of DERS' application for approval of the NSA on the eFiling System. The Commission accepts DERS' representation that sufficient notice was provided.

22. Section 6(1) of Rule 018 requires a settlement agreement to include a representation that "no party has withheld relevant information." Section 4.2 of the NSA includes the statement that each party represents that it has not withheld information relevant to the application.

[6] *ATCO Electric Limited v Alberta (Energy and Utilities Board)*, 2004 ABCA 215, paragraphs 141-143.
[7] Exhibit 26207-X0110, paragraphs 17 and 19.
[8] Exhibits 26207-X0069 and 26207-X0078.

23. DERS' application included all the information required by Section 6(3) of Rule 018, including the settlement agreement, details of the NSP and other details in its settlement brief.[9] In addition, the mediated settlement process followed the directions provided by the Commission in its January 29, 2021, letter.[10]

24. DERS summarized the mediation process as follows:

(a) Six video-conferencing all-party mediated negotiation sessions were held;

(b) DERS provided additional information to the UCA and the CCA about its revenue requirements, as requested;

(c) Various drafts and revised drafts of settlement proposals were exchanged between the Parties;

(d) An agreement-in-principle was reached on March 30, 2021; and

(e) The Parties negotiated and drafted the Settlement Agreement based on the agreement-in-principle.[11]

25. In consideration of the requirements of Rule 018, parties had sufficient notice and the opportunity to participate meaningfully in the negotiations with information responses posted on the eFiling System, and all parties representing that they did not withhold information. In the Commission's view, the record was well developed due to the IRs put to DERS by the parties, and the responses. The Commission is satisfied that the CCA and the UCA had the necessary information to participate fully in negotiations. The Commission gave parties a sufficient period of approximately two months for negotiations to take place.

26. The Commission considers that the CCA and the UCA are sophisticated parties with significant experience in negotiated settlements and proceedings to establish the RRT and DRT. The CCA and the UCA represent the majority of DERS' RRT and DRT customers, with the CCA representing primarily residential customers, and the UCA mandated by the Alberta Government to represent the interests of residential, farm and small business customers.

27. DERS informed the Commission that negotiations among the parties took place using secure video-conferencing platforms as well as email exchanges and telephone calls. The UCA and the CCA each retained two consultants during the negotiations as well as legal counsel.[12] No concerns regarding the negotiation process were filed by any of the parties. The Commission also relied on the involvement of the two qualified mediators in the negotiations to further satisfy itself that the process was fair.

4.2 Public interest

28. The second question is whether the NSA is in the public interest, including whether or not it will result in rates that are just and reasonable. In conducting its review of the NSA, the Commission considered Section 8(2) of Rule 018, which requires that the Commission intervene

[9] The Commission issued an IR to obtain the settled DRT energy-related monthly procurement labour and the DRT energy-related charges on a $/GJ basis for each of 2020-2022, to be included in the monthly GCFR filings.
[10] Exhibit 26207-X0069.
[11] Exhibit 26207-X0110, paragraph 16.
[12] Exhibit 26207-X0110, paragraph 14.

if it determines that a unanimous settlement is patently against the public interest or contrary to law.

29. In conducting the public interest assessment and because the Commission must consider the NSA as a whole,[13] the Commission considered the public interest from the ratepayers' perspective in accordance with the guidance provided by the Alberta Court of Appeal referred to in Section 3. The Commission also considered whether the effect of the NSA, taken as a whole, would lead to rates and terms and conditions of service that are just and reasonable. In addition, in considering the public interest, the Commission reviewed the material provisions of the NSA to determine if any of these provisions appear to be contrary to accepted regulatory practices, or could result in undue rate impacts, service concerns, or other difficulties in future rate applications.

30. The NSA represents a unanimous agreement reached through a negotiation process involving both the CCA and the UCA. This fact, and the fact that the CCA and the UCA collectively represent the interests of a majority of DERS' RRT and DRT customers, support the Commission's finding that the NSA is in the public interest. In addition, the Commission reviewed each of the provisions of the NSA and has determined that none of the provisions appear to be contrary to accepted regulatory practices, are unusual, or could result in unintended rate effects, or other difficulties in future rate applications. The Commission notes that the NSA does not contemplate any changes to DERS' terms and conditions of service so there are no service-related concerns associated with the settlement.[14] Further, DERS noted that approval of the NSA is not expected to materially impact its ability to meet its service requirements.[15]

31. The following are key items of the relief sought by DERS in its 2020-2022 DRT and RRT non-energy application:

(a) DRT non-energy revenue requirement;

(b) RRT non-energy revenue requirement;

(c) DRT energy-related revenue requirement;

(d) RRT energy-related revenue requirement;

(e) An annual cost of capital rate for DRT and RRT working capital of 1.39 per cent plus taxes payable expenses;

(f) Continuation of the DRT and RRT reserve accounts for hearing costs;

(g) The methodology described in Section 7 of the application to allocate the revenue requirements to rate classes and the resulting DRT and RRT rates summarized in Section 8;

(h) The inclusion of DRT energy-related items in the monthly gas cost flow-through rates (GCFR). Procurement labour will be included as a fixed monthly dollar amount with working capital, credit charges, energy-related bad debt and late payment charge revenue included on a dollar per gigajoule ($/GJ) basis;

13 Exhibit 26207-X0109, Section 5.1.
14 Exhibit 26207-X0110, paragraph 10(f).
15 Exhibit 26207-X0110, paragraph 52.

(i) A reasonable return margin for DRT services to be included in the determination of the monthly GCFR, effective for the entire test period on a $/GJ basis; and

(k) The final DRT and RRT rate schedules for 2020, 2021 and 2022.[16]

32. In the foregoing list, reference to item (j), update to the methodology for calculating the RRT energy return margin, is omitted because the Commission determined that the RRT energy return margin should be excluded from the scope of this proceeding.[17]

33. In the NSA, DERS requested the Commission grant the relief sought by DERS in the application except as modified in the NSA.[18]

34. The NSA modified the relief sought for the following key items in the application referenced in paragraph 31:

(a) DRT non-energy revenue requirement;

(b) RRT non-energy revenue requirement;

(c) DRT energy-related revenue requirement;

(d) RRT energy-related revenue requirement;

(i) A reasonable return margin for DRT services to be included in the determination of the monthly GCFR, effective for the entire test period on a $/GJ basis; and

(k) The final DRT and RRT rate schedules for 2020, 2021 and 2022.

35. Through additional process after mediation, DERS clarified that it required modified relief for DRT energy-related items in the monthly GCFR.

36. In particular, the DRT energy-related monthly procurement labour, the $/GJ charge for DRT energy-related working capital, credit charges, bad debt and late payment charge revenue, and the DRT return margin, respectively items (h) and (i) of the key items in the application, require identification and disclosure because these rates serve as inputs to DERS' monthly gas filings.

37. DERS submitted that the NSA has five principal aspects:

(a) Revised revenue requirement forecasts, inputs and assumptions;

(b) Bad debt deferral account and late payment charge deferral account;

(c) Revised DRT and RRT revenue requirements;

(d) Revised DRT and RRT rate schedules; and

(e) Commitments for future action.

38. These five principal aspects are discussed below and address all key items of the original application, including those key items that were modified as a result of the negotiations. Certain

16 Exhibit 26207-X0002, application, paragraph 3.
17 Exhibit 26207-X0069, paragraph 7.
18 Exhibit 26207-X0109, Section 2.3(b).

costs specific to the energy operations of the DRT are included as part of the NSA. These costs and the resulting rates, along with the DRT return margin, are included as part of the GCFR that DERS files for Commission acknowledgment on a monthly basis. The Commission has separately identified these costs and rates, and they are addressed in Section 4.2.2. below.

39. Having taken into account all information on the record, and for the reasons provided throughout Section 4.2, the Commission finds that the settlement is in the public interest and will result in rates that are just and reasonable.

4.2.1 Analysis of five principal aspects in the NSA

4.2.1.1 Revised revenue requirement forecasts, inputs and assumptions

40. The DRT and RRT revenue requirements are based on forecast costs and revenues. Many of the inputs used to calculate the revised revenue requirements were the subject of updated information provided through DERS' IR responses.[19] DERS stated that the net result is a reduction to aggregate DRT and RRT revenue requirements relative to the original application.[20]

41. A comparison of non-energy and energy requirements for the DRT and RRT is shown below in Table 1.

Table 1. Comparison of revenue requirements before and after mediation

Category	Year	Original application[21]	NSA[22]
		($ million)	
DRT non-energy revenue requirement	2020	54.7	51.1
	2021	58.5	50.2
	2022	54.9	48.3
RRT non-energy revenue requirement	2020	18.9	16.5
	2021	21.7	16.7
	2022	19.9	15.8
DRT energy revenue requirement	2020	4.4	3.4
	2021	6.0	2.8
	2022	4.6	2.1
RRT energy revenue requirement	2020	1.8	1.5
	2021	2.5	1.2
	2022	1.9	0.9

*All figures are rounded to the nearest $100,000.

42. The Commission notes that the net result of the settlement is a reduction to aggregate DRT and RRT revenue requirements relative to what was requested in the original application.[23] In addition, the rates in the NSA are derived from the agreed-upon revenue requirements by the

19 Exhibit 26207-X0110, paragraph 22.
20 Exhibit 26207-X0110, paragraph 23.
21 Exhibit 26207-X0002, application, paragraph 3.
22 Exhibits 26207-X0111 and 26207-X0113.
23 Exhibit 26207-X0110, paragraph 23. These amounts were determined without considering bad debt expense, late payment charge revenue and hearing reserve amounts because they are each subject to deferral account treatment.

same allocation methodology that is in the DRT RRT application, and most recently approved by the Commission in Decision 24237-D01-2019.[24]

43. The revenue requirements in the NSA have resulted in slight rate increases compared to 2019 approved rates. For DRT residential customers, the 2019 final rates are $0.284 per site per day, while the NSA rates are $0.287 per site per day in 2020, $0.294 per site per day in 2021 and $0.294 per site per day in 2022. This translates to an annual bill increase of $1.10 in 2020 for a typical residential customer,[25] followed by an increase of $2.56 in 2021 and no increase in 2022. For RRT residential customers, the 2019 final rates are $0.455 per site per day, while the NSA rates are $0.459 per site per day in 2020, $0.475 per site per day in 2021 and $0.460 per site per day in 2022. This translates to an annual bill increase of $1.46 in 2020 for a typical residential customer,[26] followed by an increase of $5.84 in 2021 and a decrease of $5.48 in 2022. The Commission considers the increases to be reasonable because the impact on rates is minimal.

4.2.1.2 Bad debt deferral account and late payment charge deferral account

44. DERS and interveners agreed to implement deferral accounts for bad debt and late payment charge. The parties agreed that forecasts for 2021 and 2022 on bad debt and late payment charge would be subject to deferral account treatment.

45. DERS explained that the bad debt deferral account includes an incentive mechanism that results in DERS carrying some risk, and with some chance of reward. It added that "this mechanism reduces DERS' risk exposure to exceptionally high bad debt, and allows DERS to share in the benefit of exceptionally low bad debt."[27] Customers also benefit by the design of this incentive mechanism because it shields customers from exceptionally high bad debt.

46. The bad debt revenue requirements in the NSA are used to calculate the applied-for rates. However, the thresholds of the incentive mechanism distinguishing risk and reward are derived from bad debt revenue requirements from both DERS' IR responses during mediation and as a result of the NSA. An illustrative bad debt deferral account and late payment charge deferral account model is included as Appendix E to the NSA.[28]

47. In DERS' IR responses during mediation,[29] DERS identified the following bad debt revenue requirements:

Table 2. Bad debt revenue requirements per IR responses

Bad debt	2020	2021	2022
		($000)	
DRT and RRT (energy)	4,865.2	6,848.5	5,752.7
DRT and RRT (non-energy)	12,944.8	18,224.0	15,309.8
Total	17,810	25,072.5	21,062.5

24 Exhibit 26207-X0110, paragraph 53.
25 Calculation is based on the difference in rates multiplied by the number of days in a year: $0.003 * 365 = $1.10.
26 Calculation is based on the difference in rates multiplied by the number of days in a year: $0.004 * 365 = $1.46.
27 Exhibit 26207-X0110, paragraph 26.
28 Exhibit 26207-X0115, Appendix E- Illustrative Bad Debt Deferral Account and LPC [late payment charge] Deferral A.
29 Exhibit 26207-X0098, DERS-CCA-2021FEB23-009a.

48. In the revised RRT and DRT revenue requirement per the NSA,[30] the parties agreed to the following bad debt revenue requirements:

Table 3. Bad debt revenue requirements per the NSA

Bad debt	2020 (actual)	2021	2022
	($000)		
DRT and RRT (energy)	4,891.3	5,100.3	3,998.8
DRT and RRT (non-energy)	12,918.7	13,472.2	10,563.6
Total	17,810	18,572.5	14,562.4

49. An explanation of how the incentive mechanism works for the 2021 and 2022 test years was described by DERS in the NSA:

> If actual bad debt expense in either of 2021 and 2022 is lower than the agreed-upon forecasts for 2021 and 2022, above, 75% of the difference, for each year, will be deferred to the Bad Debt Deferral Account, to the credit of customers.
>
> If the bad debt expense in either of 2021 and 2022 is greater than the agreed-upon forecasts for 2021 and 2022, above, 100% of the difference, for each year, will be deferred to the Bad Debt Deferral Account, to the account of customers, up to threshold amounts of $25,072,500 for 2021 and $21,062,000 for 2022.
>
> If the actual bad debt expense in either of 2021 and 2022 is greater than the threshold amounts of $25,072,500 for 2021 and $21,062,000 for 2022, then:
>
> - $6,500,000 and $6,500,000, in regard to 2021 and 2022, respectively, will be deferred to the Bad Debt Deferral Account to the account of customers; and
>
> - 50% of the difference between actual bad debt expense and $25,072,500 for 2021, and $21,062,000 for 2022, will be deferred to the Bad Debt Deferral Account, to the account of customers.[31]

50. The deferral treatment for late payment charge captures 100 per cent of the difference between the agreed forecasts and actuals.

51. DERS indicated that interest would be accrued on combined deferral accounts, to the credit of either DERS or its customers. Additionally, DERS will apply for the disposition of the net balance of the deferral accounts, including interest, based on 2021 and 2022 actuals in its next non-energy rate application for the test period starting 2023 or in a stand-alone application.[32]

52. Recognizing that differing assumptions factoring into bad debt forecasts will lead to wide-ranging results, the Commission considers that the incentive mechanism introduced into the bad debt deferral account, which provides both risk or rewards to both DERS and its customers, is an appropriate solution to approach an issue with uncertain outcomes.

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30 Exhibit 26207-X0111, Appendix A – Revised 2020-2022 DRT Revenue Requirements, Combined DRT and RRT Summary.
31 Exhibit 26207-X0109, Section 2.1(j)(3), PDF pages 9-10.
32 Exhibit 26207-X0109, sections 2.1 (j)(5) and 2.1 (j)(6), PDF page 10.

4.2.1.3 Revised DRT and RRT revenue requirements

53. DERS advised that some of the revised revenue requirement inputs are interdependent, and because they were agreed to in the aggregate for both DRT and RRT, they are not in all cases consistent with the corresponding figures in the revised revenue requirement models.[33] DERS added that in some cases, the substitution of the revised revenue requirement inputs required changes to other inputs that were not expressly agreed to.[34] However, in the case of any inconsistency, the parties agreed that the figures in the revised revenue requirement models prevail.[35]

4.2.1.4 Revised DRT and RRT rate schedules

54. The title for these rate schedules indicate 2020 Final Rate Schedules, 2021 Final Rate Schedules and 2022 Final Rate Schedules for the DRT and RRT. The Commission understands the word "final" to express finality to the conclusion of negotiations. The Commission considers 2020 rates to be final, and that 2021 and 2022 rates are final, subject to the finalization of the bad debt and late payment charge deferral accounts.

4.2.1.5 Commitments for future action

55. The Commission acknowledges that parties have agreed to certain future actions. These future actions include:

- applying for revenue requirements and rates based on the most recently available public data on regulated-to-competitive customer ratio from the Market Surveillance Administrator;
- providing semi-annual reports to the UCA and the CCA on its accrued bad debt expense and late payment charge revenue;
- providing timely notice of any material changes to its collection practices to the UCA and the CCA;
- holding stakeholder sessions regarding bad debt and late payment charge revenue;
- consulting with the UCA and the CCA regarding its customer survey questions and exit surveys; and
- providing timely notice to the UCA and the CCA of any response received to its letter to the Minister of Finance regarding federal fuel charge bad debt impact, or any changes in policy or law regarding federal fuel charges.[36]

[33] Exhibit 26207-X0110, paragraph 29.
[34] Exhibit 26207-X0110, paragraph 30.
[35] Exhibit 26207-X0111, NSA Appendix A – Revised 2020-2022 DRT revenue requirements, and Exhibit 26207-X0113, NSA Appendix C – Revised 2020-2022 RRT revenue requirements.
[36] Exhibit 26207-X0110, paragraph 32.

56. The Commission understands that the costs of the CCA for its participation in these activities are not included as costs in relation to DERS' application and the related settlement process, which concluded at the point of approval of the agreement.[37]

4.2.2 Findings on rates for GCFR

57. As DERS is a default supply provider, it must submit a monthly gas filing to the Commission for approval of its proposed gas cost flow-through rate, commonly referred to as the GCFR.[38] The GCFR is determined from various inputs including the DRT energy-related procurement labour, and the DRT energy-related charges for credit costs, working capital, bad debts and penalty revenue requested in non-energy applications.

58. The DRT energy-related rates affecting DERS' GCFR filings are the fixed monthly dollar amount related to procurement labour, and the working capital, credit charges, energy-related bad debt and late payment charge are on a $/GJ basis.

59. As the energy procurement labour costs and the DRT energy-related charges per GJ were not updated in the body of the NSA, the Commission issued IRs after the filing of the NSA to request calculations from DERS. DERS provided the following tables:[39]

Table 4. DRT labour (gas procurement) monthly GCFR amounts

	2020	2021	2022
	($000)		
Labour (gas procurement)	399.0	407.9	414.0
Monthly GCFR amount	33.3	34.0	34.5

Table 5. DRT energy-related revenue requirements

	2020	2021	2022
Credit charges ($000)	228.4	252.0	244.0
Working capital ($000)	63.5	67.2	52.7
Bad debt ($000)	3,162.2	3,279.4	2,556.5
Penalty revenue ($000)	(483.1)	(1,223.1)	(1,150.9)
DRT energy-related (collected per GJ) [*sic*]	2,907.9	2,375.5	1,702.3
DRT forecast consumption (GJ)	94,723,977	86,811,679	82,871,649
DRT energy-related charges ($/GJ)	0.031	0.027	0.021

60. In addition to the GCFR, DERS applies for approval of Rider F in its monthly filings. One of the inputs to Rider F is the DRT return margin, which is a rate requested in DERS' non-energy applications.

61. The Commission notes that the return margin in the NSA was determined in accordance with methodologies previously approved for DERS since 2007.[40] The revised DRT return margin

37 Exhibit 26207-X0109, Section 2.11, PDF pages 14-15.
38 *Default Gas Supply Regulation*, sections 3(4)(b)(i) and 3(5).
39 Exhibit 26207-X0131, DERS-AUC-2021MAY04-001.
40 Decision 2007-103: Direct Energy Regulated Services, 2007-2008 Default Rate Tariffs and Regulated Rate Tariffs, Proceeding 15915, Application 1492697-1, December 20, 2007.

is found in Tab 5.1.14, DRT Return Margin of the 2020-2022 DRT Revenue Requirements, in the NSA.[41]

Table 6. DRT return margin

	2020 (actual)	2021	2022
	$/GJ		
DRT return margin	0.050	0.052	0.053

62. The Commission has reviewed the DRT energy-related rates in tables 4 to 6 and approves these rates as inputs to DERS' monthly gas filings, on a final basis, with the exception subsequently described. The Commission considers that the DRT energy-related rates in tables 4 and 6 are final for 2020, 2021 and 2022 because these amounts are not subject to deferral account treatment. While the Commission considers that the DRT energy-related rate in Table 5 is final for 2020, the 2021 and 2022 rates are approved on a final basis, subject to the finalization of the bad debt and late payment charge deferral accounts.

63. To streamline future non-energy applications where negotiated settlements are reached, the Commission encourages DERS to clearly state all DRT energy-related rates, which are required for monthly GCFR filings, in the body of future NSAs.

4.3 Approval of the NSA

64. The NSA consists of the following documents:

- The executed NSA with signatures[42]
- Appendix A – Revised 2020-2022 DRT Revenue Requirements[43]
- Appendix B – Revised 2020-2022 DRT Rate Schedules[44]
- Appendix C – Revised 2020-2022 RRT Revenue Requirements[45]
- Appendix D – Revised 2020-2022 RRT Rate Schedules[46]
- Appendix E – Illustrative Bad Debt Deferral Account and LPC Deferral Account Model[47]
- Appendix F – Illustrative Bi-Annual Bad Debt and Late Payment Charge Revenue Report[48]

65. Based on the NSA, the record of this proceeding and as a result of the Commission's finding in paragraph 39 above that the settlement is in the public interest and will result in rates that are just and reasonable, as well as the Commission's considerations as set out in Section 4.2.1 and its subsections, and Section 4.2.2, the Commission approves the NSA, attached

41 Exhibit 26207-X0111.
42 Exhibit 26207-X0109.
43 Exhibit 26207-X0111, Revised 2020-2022 DRT Revenue Requirements.
44 Exhibit 26207-X0112, Revised 2020-2022 DRT Rate Schedules. Schedules in Word format are available in exhibits 26207-X0117 to 26207-X0122.
45 Exhibit 26207-X0113, Revised 2020-2022 RRT Revenue Requirements.
46 Exhibit 26207-X0114, Revised 2020-2022 RRT Rate Schedules. Schedules in Word format are available in exhibits 26207-X0123 to 26207-X0125.
47 Exhibit 26207-X0115, Illustrative Bad Debt Deferral Account and LPC Deferral Account Model.
48 Exhibit 26207-X0116, Illustrative Bi-Annual Bad Debt and Late Payment Charge Revenue Report.

as Appendix 3 to this decision, and its appendixes in their entirety, as filed in the following exhibits:

- The executed NSA with signatures (Exhibit 26207-X0109)
- Appendix A: Revised 2020-2022 DRT Revenue Requirements (Exhibit 26207-X0111)
- Appendix B: Revised 2020-2022 DRT Rate Schedules (Exhibit 26207-X0112)
  - 2020 DRT Rate Schedule for DERS North (Exhibit 26207-X0117)
  - 2021 DRT Rate Schedule for DERS North (Exhibit 26207-X0118)
  - 2022 DRT Rate Schedule for DERS North (Exhibit 26207-X0119)
  - 2020 DRT Rate Schedule for DERS South (Exhibit 26207-X0120)
  - 2021 DRT Rate Schedule for DERS South (Exhibit 26207-X0121)
  - 2022 DRT Rate Schedule for DERS South (Exhibit 26207-X0122)
- Appendix C: Revised 2020-2022 RRT Revenue Requirements (Exhibit 26207-X0113)
- Appendix D: Revised 2020-2022 RRT Rate Schedules (Exhibit 26207-X0114)
  - 2020 RRT Rate Schedule (Exhibit 26207-X0123)
  - 2021 RRT Rate Schedule (Exhibit 26207-X0124)
  - 2022 RRT Rate Schedule (Exhibit 26207-X0125)
- Appendix E: Illustrative Bad Debt Deferral Account and LPC Deferral Account Model (Exhibit 26207-X0115)
- Appendix F: Illustrative Bi-Annual Bad Debt and Late Payment Charge Revenue Report (Exhibit 26207-X0116)

66. DERS also included the rate schedules for the Rural Electrification Association (REA) customers as appendixes to the NSA.[49] The Commission considers that this information has been provided for information purposes, as it has been in the past.[50] The Commission does not approve rates for REAs as their rates and riders are subject to approval by the board of directors of the REA.[51] Consequently, the Commission has excluded the REA rate schedules from its consideration in its review and approval of the NSA and accepts them for information purposes only.

5 Matters outside of the NSA

5.1 Motion for confidentiality

67. DERS filed a motion for confidentiality as part of its application. On January 8, 2021, DERS filed additional information to clarify its confidentiality motion, and on January 15, 2021, DERS filed supplemental information to support its confidentiality motion. There were a

[49] Exhibits 26207-X0126 to 26207-X0128.
[50] For example, see Proceeding 15915 where DERS included separate rate schedules and terms and conditions for the REAs for the board's information on pages 78 and 87 of its application.
[51] *Electric Utilities Act*, Section 102(2)(c).

significant number of redactions requested on a large number of application documents, and Commission staff spent considerable time working with DERS to confirm the information required to properly develop its motion for confidentiality. In future applications where confidentiality motions are contemplated, DERS is encouraged to submit these motions in advance of filing the application so that Commission staff can focus on the application itself once filed and stay on course to meet regulatory efficiency goals.

5.2 Finding – compliance with Decision 24237-D01-2019

68. In this section, the Commission determines whether DERS has complied with the directions provided in Decision 24237-D01-2019 based on its application.

Direction at paragraph 133

69. The direction at paragraph 133 of Decision 24237-D01-2019 pertained to identifying costs DERS incurred for retaining external consultants to assist it with the selection of its post-2019 Customer Care and Billing (CC&B) service provider and for undertaking a benchmark study to determine the fair market value for CC&B in 2020 and beyond. The Commission requested DERS to clearly identify which cost category these costs are included in, as well as the dollar and percentage of the costs that have been allocated to DERS.

70. DERS identified the external consultants and provided the breakdown of costs allocated between the DRT and RRT in its application on Table 2.0 – A Summary of Costs Included in Other Administration in 2020. These costs are included in the consulting cost category of Schedule 5.1.10 of the DRT revenue requirements rate model and Schedule 5.2.10 of the RRT revenue requirement rate model. The Commission is satisfied that DERS included the information requested in Decision 24237-D01-2019 and finds that DERS has complied with the direction at paragraph 133 of Decision 24237-D01-2019.

Direction at paragraph 167

71. The direction at paragraph 167 of Decision 24237-D01-2019 concerned the details to be provided as part of how costs are allocated from Centrica to North American Home (NAH), and from NAH to the Canadian line of business.

72. DERS provided an explanation of its two-step cost allocation methodology in Section 5.5.15 of the application. The allocation method from the Direct Energy North America corporate function cost pool to NAH is provided in the cost centre assessment provided in Attachment 33 – Corporate Costs Assessment Review. The second step of the allocation method was to allocate costs from NAH to DERS. DERS included Attachment 32 – Corporate Costs Analysis 2019-2020, which provided the detailed analysis at the cost centre level. The Commission is satisfied that DERS has supported its allocation methodology by providing a thorough review of its cost centres, allocation drivers, the reasoning behind its cost allocation methodology and total costs involved.

Direction at paragraph 168

73. The direction at paragraph 168 of Decision 24237-D01-2019 related to detailed variance reporting on the differences between prior years’ actual and approved corporate services costs, to be included in DERS’ next DRT and RRT application. The Commission directed DERS to

provide detailed variance reporting by corporate group function and cost centre between the 2019 actual and approved corporate costs.

74. DERS explained that it would be difficult to provide the variance between the 2019 approved forecast and the 2019 actuals because it was not done on a purely cost centre basis. The Commission accepts DERS' explanation and grants relief to DERS from having to comply with the direction in paragraph 168 of Decision 24237-D01-2019.

75. In Attachment 32 to the application, DERS provided a detailed explanation at the cost centre level for the variances between the 2019 actuals and the 2020 forecast. The variance explanations provide insight into the organization of services under cost centres, and the reason that prompted the reorganization of cost centres. The Commission accepts DERS' variance explanations to justify the changes to its cost centres.

Direction at paragraph 172

76. The direction at paragraph 172 of Decision 24237-D01-2019 relates to services that DERS requires from corporate services and how corporate services costs are allocated. The direction stated that DERS should address whether the costs of the corporate services being allocated to DERS are required for DERS to provide regulated gas and electricity service in Alberta, are being allocated using a transparent and fair allocation basis, and if they are being provided on a lower cost basis than DERS could provide itself or through an independent third party. The Commission directed DERS to include an examination and discussion of various allocation methodologies as part of the corporate cost study.

77. In Section 5.5.15 of the application and in Attachment 33, DERS explained it undertook a thorough review of the methodology used to allocate corporate costs from Direct Energy North America to DERS. For each of the cost centres, DERS applied a benefit test to determine whether the service provided a benefit to DERS, an allocation driver test to determine whether the method of allocation proposed was reasonable, and a reasonable cost test to determine whether it would be more cost-effective for DERS to undertake the service itself or seek a third-party to do so. The Commission is satisfied that DERS has complied with the direction at paragraph 172 of Decision 24237-D01-2019.

5.3 True-up of interim rates

78. The Commission approved 2019 DRT and RRT non-energy interim rates for DERS in Decision 23989-D01-2018,[52] and the Commission approved the same rates as interim rates for 2020 in Decision 24237-D01-2019.[53] In DERS' 2020 DRT and RRT interim rates application, DERS requested revised interim rates, and the Commission approved the rate changes effective October 1, 2020, in Decision 25727-D01-2020.[54] DERS continues to charge the interim rates approved in Decision 25727-D01-2020.

[52] Decision 23989-D01-2018: Direct Energy Regulated Services, 2019 Interim Rates Application, Proceeding 23989, December 3, 2018, Appendix 2, Appendix 3 and Appendix 4.

[53] Decision 24237-D01-2019: Direct Energy Regulated Services, 2019 Default Rate Tariff and Regulated Rate Tariff Application, Proceeding 24237, December 5, 2019, paragraph 239.

[54] Decision 25727-D01-2020: Direct Energy Regulated Services, 2019 Interim Rates Application, Proceeding 25727, September 14, 2020, Appendix 2, Appendix 3 and Appendix 4.

79. Consequently, DERS operated under Commission-approved interim rates for all of 2020 and continues to operate under interim rates. These interim rates should be trued up to the final rates for 2020 and 2021 approved in this decision. Accordingly, the Commission directs DERS to file a separate application for the true-up of each of the approved 2020 and 2021 rates from the period January 1, 2020, to June 30, 2021, after it has completed billing on interim rates for service up to June 30, 2021.

6 Order

80. It is hereby ordered that:

(1) In accordance with the findings in this decision, the negotiated settlement agreement, as described in paragraph 65 of this decision, is approved as filed.

(2) The default rate tariff rate schedules for Direct Energy Regulated Services, as set out in Appendix 4 and Appendix 5 for the north and south, respectively, and attached to this decision, are approved on a final basis effective July 1, 2021, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2021.

(3) The default rate tariff rate schedules for Direct Energy Regulated Services, as set out in Appendix 6 and Appendix 7 for the north and south, respectively, and attached to this decision, are approved on a final basis effective January 1, 2022, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2022.

(4) The default rate tariff return margin charge of $0.052 per gigajoule for Direct Energy Regulated Services is approved on a final basis, effective July 1, 2021.

(5) The default rate tariff return margin charge of $0.053 per gigajoule for Direct Energy Regulated Services is approved on a final basis, effective January 1 2022.

(6) The default rate tariff charge of $0.027 per gigajoule for the energy-related portion of credit charges, working capital, bad debt and late payment charges for Direct Energy Regulated Services is approved on a final basis effective July 1, 2021, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2021.

(7) The default rate tariff charge of $0.021 per gigajoule for the energy-related portion of credit charges, working capital, bad debt and late payment charges for Direct Energy Regulated Services is approved on a final basis effective January 1, 2022, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2022.

(8) The regulated rate tariff rate schedules for Direct Energy Regulated Services, as set out in Appendix 8 to this decision, are approved on a final basis effective July 1, 2021, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2021.

(9) The regulated rate tariff rate schedules for Direct Energy Regulated Services, as set out in Appendix 9 to this decision, are approved on a final basis effective January 1, 2022, subject to the finalization of the bad debt deferral account and late payment charge deferral account for 2022.

Dated on June 4, 2021.

Alberta Utilities Commission

(original signed by)

Carolyn Dahl Rees
Chair

(original signed by)

Vera Slawinski
Commission Member

(original signed by)

Vincent Kostesky
Acting Commission Member

Appendix 1 – Proceeding participants

Name of organization (abbreviation) Company name of counsel or representative
Direct Energy Regulated Services (DERS) Lawson Lundell Barristers & Solicitors
Consumers' Coalition of Alberta (CCA)
Office of the Utilities Consumer Advocate (UCA) Reynolds, Mirth, Richards & Farmer LLP

Alberta Utilities Commission Commission panel C. Dahl Rees, Chair V. Slawinski, Commission Member V. Kostesky, Acting Commission Member Commission staff D. Reese (Commission counsel) E. Chu D. Mitchell

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. Consequently, DERS operated under Commission-approved interim rates for all of 2020 and continues to operate under interim rates. These interim rates should be trued up to the final rates for 2020 and 2021 approved in this decision. Accordingly, the Commission directs DERS to file a separate application for the true-up of each of the approved 2020 and 2021 rates from the period January 1, 2020, to June 30, 2021, after it has completed billing on interim rates for service up to June 30, 2021.................................. paragraph 79

Appendix 3 – Executed NSA

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Appendix 3 -
Executed NSA

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Appendix 4 – 2021 DRT rate schedule for DERS North

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Appendix 4 - 2021
DRT rate schedule fo

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Appendix 5 – 2021 DRT rate schedule for DERS South

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Appendix 5 - 2021
DRT rate schedule fc

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Appendix 6 – 2022 DRT rate schedule for DERS North

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Appendix 6 - 2022
DRT rate schedule fo

(consists of 6 pages)

Appendix 7 – 2022 DRT rate schedule for DERS South

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Appendix 7 - 2022
DRT rate schedule fo

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Appendix 8 – 2021 RRT rate schedule

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Appendix 8 - 2021
RRT rate schedule

(consists of 11 pages)

Appendix 9 – 2022 RRT rate schedule

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Appendix 9 - 2022
RRT rate schedule

(consists of 11 pages)

Negotiated Settlement Agreement

Direct Energy Regulated Services
2020-2022 Default Rate Tariff and Regulated Rate Tariff Application

Proceeding 26207

THIS AGREEMENT for the negotiated settlement of the 2020-2022 Default Rate Tariff and Regulated Rate Tariff Application is made and entered into as of April 20, 2021

Among:

DIRECT ENERGY REGULATED SERVICES, a business unit of Direct Energy Marketing Limited

-and-

CONSUMERS' COALITION OF ALBERTA, a coalition of the Alberta Consumers' Association and the Alberta Council on Aging, each incorporated under the *Societies Act*, RSA 2000, c. S-14

-and-

OFFICE OF THE UTILITIES CONSUMER ADVOCATE, established by Schedule 13.1 of the *Government Organization Act*, RSA 2000, Chapter G-10

WHEREAS:

(a) Direct Energy Regulated Services ("**DERS**") performs the Default Rate Tariff ("**DRT**") and Regulated Rate Tariff ("**RRT**") functions in the service territories of ATCO Gas and Pipelines Ltd. and ATCO Electric Ltd (collectively, "**ATCO**"), respectively;

(b) The Alberta Utilities Commission ("**AUC**" or "**Commission**") regulates DERS' operations including the determination of the DRT and RRT rates for the ATCO service territories;

(c) DERS is currently operating under the interim DRT and RRT rates approved by the AUC in Decision 25727-D01-2020, effective October 1, 2020;

(d) On December 21, 2020 DERS filed an application with the AUC requesting approval of its 2020-2022 DRT and RRT rates ("**Application**");

(e) On December 22, 2020, the AUC issued a notice of application informing potentially interested parties that it would be considering the Application;

(f) The Consumers' Coalition of Alberta ("**CCA**") and the Office of the Utilities Consumer Advocate ("**UCA**") registered to intervene in the hearing of the Application on December 29, 2020 and January 8, 2021, respectively;

(g) On January 29, 2021, the AUC issued a letter directing that DERS, the CCA, and the UCA (each a "**Party**", and collectively the "**Parties**") participate in a mandatory mediation settlement process for the Application (the "**Mediation**");

(h) The AUC appointed Mr. Jack Marshall, Q.C. and Mr. Douglas Crowther, Q.C. as co-mediators for the Mediation;

(i) The AUC directed that the Mediation period would be from February 1, 2021 to April 1, 2021, and would include an information request ("**IR**") process limited to a maximum of 50 IRs from each intervener;

(j) On February 23, 2021, the UCA and CCA each issued IRs to DERS;

(k) On March 9, 2021, DERS responded to both UCA and CCA IRs, on the public record of this proceeding, Exhibits 26207-X0086–X0090 and 26207-X0091-X0102;

(l) Using online meeting platforms, the Parties and the mediators met a number of times from March 24th to 30th, 2021, to attempt to negotiate a settlement of the Application;

(m) On March 30, 2021, the Parties reached an agreement-in-principle for a negotiated settlement of the Application; and

(n) This Negotiated Settlement Agreement ("**Agreement**") records the terms of the Parties' negotiated settlement.

IN CONSIDERATION of the mutual promises made in this Agreement and for other good and valuable consideration, the receipt and sufficiency of which is hereby expressly acknowledged by each of the Parties, and subject to the conditions set out below, the Parties agree as follows:

ARTICLE 1
INTERPRETATION

1.1 Defined Terms

As used in this Agreement, the following capitalized terms have the meaning set out below:

(a) "**Bad Debt Deferral Account**" means the deferral account described at section 2.1(j);

(b) "**EUA**" means the *Electric Utilities Act*, S.A. 2003, c. E-5.1;

(c) "**Default Rate Tariff**" or "**DRT**" means the tariff required by the DGS Reg;

(d) "**DGS Reg**" means the *Default Gas Supply Regulation*, Alta Reg 184/2003;

(e) "**FTE**" means full-time equivalent;

(f) "**GUA**" means the *Gas Utilities Act*, RSA 2000, c G-5;

(g) "**LPC Deferral Account**" means the deferral account described at section 2.1(j);

(h) "**MSA Data**" means the publicly-available, market share data provided by the Alberta Market Surveillance Administrator at the "Retail Statistics" page of www.albertamsa.ca;

(i) "**Proceeding**" means AUC Proceeding No. 26207 concerning DERS' 2020-2022 DRT and RRT Application;

(j) "**REA**" means rural electrification association;

(k) "**RRO Reg**" means the *Regulated Rate Option Regulation*, Alta Reg 262/2005;

(l) "**Regulated Rate Tariff**" or "**RRT**" means the tariff required by the RRO Reg;

(m) "**Test Period**" means, collectively, calendar years 2020, 2021, and 2022.

1.2 Other Defined Terms

Capitalized terms not defined in this Agreement have the meaning given to them in the Application.

1.3 Gender and Number

Any reference in this Agreement to gender includes all genders and words denoting the singular shall include the plural and *vice versa*, as the context requires.

1.4 Headings

The division of the Agreement into separate articles and sections and the insertion of headings are for convenience only and shall not affect the interpretation of this Agreement.

1.5 Including

In the Agreement, the words "includes," "including" and similar expressions mean "includes" (or "including") without limitation.

1.6 Legal Representation

Each Party acknowledges that it has been represented by counsel in connection with the Mediation and with respect to the negotiation, drafting, and execution of the Agreement.

1.7 References to Statutes and Regulations

Any reference to a statute, regulation or AUC rule is a reference to it as re-enacted, varied, amended, modified, supplemented or replaced from time to time.

1.8 Entire Agreement

The Agreement sets out the entire understanding and agreement of the Parties and there are no representations, warranties, covenants, conditions or other agreements, express or implied, collateral, statutory or otherwise, among the Parties in connection with the subject matter of this Agreement except as specifically set out in this Agreement.

1.9 Successor and Assigns

This Agreement becomes effective only when executed by all of the Parties and then approved by the AUC. This Agreement will then be binding on and enure to the benefit of the Parties and their respective successors. No Party may assign this Agreement without the prior written consent of the other Parties, provided that such consent will not be unreasonably withheld.

1.10 Amendments

The Agreement may be modified, altered or amended only by an agreement in writing, signed by the Parties and approved by the AUC.

1.11 No Waiver

No waiver of any provision of the Agreement will be valid or enforceable unless in writing and signed by the Party against whom enforcement of the waiver is sought. The waiver of any provision of this Agreement, at any time, by any Party, will not constitute a waiver of future compliance with that provision or a waiver of compliance with any other provision of the Agreement.

1.12 Governing Law

The Agreement and all disputes arising in connection with it will be subject to, governed by, and construed in accordance with the laws of the Province of Alberta including the laws of Canada that are applicable within the Province of Alberta.

1.13 Severability

In the event that any of the provisions of this Agreement are held by a court of competent jurisdiction to be invalid, all other provisions of this Agreement will remain enforceable to the fullest extent permitted by law.

1.14 Execution

This Agreement may be executed by facsimile transmission or by providing a scanned copy of the executed execution page, and may be executed by different Parties in different counterparts, each of which will be an original and all of which will constitute one and the same instrument.

1.15 Time of the Essence

Time shall be of the essence in this Agreement.

1.16 Agreed-To Dollar Amounts

In some cases, DERS, the UCA and the CCA agreed to components of the applicable revenue requirements that were expressed in precise dollar amounts. Those precisely agreed-to amounts are shown in the applicable appendices, and are only rounded to the nearest $100,000 for the purposes of brevity and describing them in this Agreement. In the event of an inconsistency, the precise agreed-to amounts shown in the appendices will prevail.

1.17 Derived Dollar Amounts

In some cases, DERS, the UCA and the CCA agreed to components of the applicable revenue requirements that are a function of, or are derived from, other agreed-to amounts, and in consequence appear slightly different in the applicable appendices. In the event of an inconsistency, the precise agreed-to amounts shown in the appendices will prevail.

1.18 Allocation between DRT and RRT

Aggregate DRT and RRT costs or revenues agreed to by Parties during the Mediation will be allocated between DRT and RRT in accordance with the methods described in the Application, consistent with Decision 24237-D01-2019, as shown in the applicable appendices.

1.19 NSA Appendices

The following appendices are included and form part of this Agreement:

(a) NSA Appendix A – Revised 2020-2022 DRT Revenue Requirement ("**NSA Appendix A**")

(b) NSA Appendix B – Revised 2020-2022 DRT Rate Schedules ("**NSA Appendix B**")

(i) Revised DERS North DRT Rate Schedules 2020

(ii) Revised DERS North DRT Rate Schedules 2021

(iii) Revised DERS North DRT Rate Schedules 2022

(iv) Revised DERS South DRT Rate Schedules 2020

(v) Revised DERS South DRT Rate Schedules 2021

(vi) Revised DERS South DRT Rate Schedules 2022

(c) NSA Appendix C – Revised 2020-2022 RRT Revenue Requirement ("**NSA Appendix C**")

(d) NSA Appendix D – Revised 2020-2022 RRT Rate Schedules ("**NSA Appendix D**")

(i) Revised DERS RRT Rate Schedules 2020

(ii) Revised DERS RRT Rate Schedules 2021

(iii) Revised DERS RRT Rate Schedules 2022

(iv) Revised DERS REA Rate Schedules 2020

(v) Revised DERS REA Rate Schedules 2021

(vi) Revised DERS REA Rate Schedules 2022

(e) NSA Appendix E – Illustrative Bad Debt Deferral Account and LPC Deferral Account Model ("**NSA Appendix E**")

(f) NSA Appendix F – Illustrative Bi-Annual Bad Debt and Late Payment Charge Revenue Report ("**NSA Appendix F**")

ARTICLE 2
TERMS OF SETTLEMENT

2.1 Approval of the Application as modified by this Agreement

Subject to other terms of this Agreement, the Parties agree that the Commission should approve the relief sought by DERS in the Application, subject to the following:

(a) Regulated and Competitive Split

In the Application, DERS applied for approval of revenue requirements that included a regulated-to-competitive customer ratio of 70%/30% for the entire Test Period (section 5.3 of the Application). The Parties agree that the Commission should approve DERS' revenue requirements based on a regulated-to-competitive customer ratio of 68.1%/31.9% for 2020; 67.4/32.6% for 2021; and 67.4/32.6% for 2022 as reflected in

NSA Appendices A and C, Schedules 5.1.9 (DRT FTE Detail), 5.2.9 (RRT FTE Detail), 5.1.1 (DRT Customer Operations, Lines 4 and 9), and 5.2.1 (RRT Customer Operations, Lines 4 and 9).

(b) Base Salary Increases

In the Application, DERS applied for combined DRT and RRT revenue requirements that included base salary increases of 0% in 2020; 2.1% for 2021; and 2.1% 2022 (section 5.4.1 of the Application and Exhibits 26207-X0003 and -X0004, Line 2 of Schedules 1.1.1 and 1.2.1, respectively). Instead, the Parties agree that the Commission should approve DERS' revenue requirements based on base salary increases of 0% for 2020; 1.5% for 2021; and 1.5% for 2022 as reflected in NSA Appendices A and C, Line 2 of Schedules 1.1.1 and 1.2.1, respectively.

(c) Customer Operations

In the Application, DERS applied for combined DRT and RRT revenue requirements that included customer operation costs of $42.4 million for 2020, $41.8 million for 2021, and $41.0 million for 2022 (section 5.5.1 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 7). Instead, the Parties agree that the Commission should approve customer operation costs of $42.4 million for 2020, $41.9 million for 2021, and $41.1 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 7. The DRT customer operations cost is reflected in NSA Appendix A, Schedule 5.1, Line 7. The RRT customer operations cost is reflected in NSA Appendix C, Schedule 5.2, Line 7.

(d) Merchant Fees Costs

In the Application, DERS applied for combined DRT and RRT revenue requirements that included merchant fee costs of $1.7 million for 2020, $2.0 million for 2021, and $2.1 million for 2022 (section 5.5.2 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 8). Instead, the Parties agree that the Commission should approve merchant fee costs of $1.6 million for 2020, $1.9 million for 2021, and $2.0 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 8. The DRT merchant fees cost is reflected in NSA Appendix A, Schedule 5.1, Line 8. The RRT merchant fees cost is reflected in NSA Appendix C, Schedule 5.2, Line 8.

(e) Working Capital

In the Application, DERS applied for combined DRT and RRT revenue requirements that included working capital costs of $0.7 million for 2020, 2021 and 2022 (section 5.5.3 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Lines 3 and 9). The Parties agree that the Commission should approve DERS' revenue requirements based on working capital costs of $0.7 million for 2020, 2021 and 2022 as derived in NSA Appendices A and C, Combined DRT RRT Summary, Line 3 and 9. The DRT working capital expense is reflected in NSA Appendix A, Schedule 5.1, Line 9. The RRT working capital expense is reflected in NSA Appendix C, Schedule 5.2, Line 9.

(f) Deemed Tax

In the Application, DERS applied for combined DRT and RRT revenue requirements that included deemed tax of $0.1 million for 2020, 2021 and 2022 (section 5.5.4 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 10). The Parties agree that the Commission should approve DERS' revenue requirements based on deemed tax of $0.1 million for 2020, 2021 and 2022 as derived in NSA Appendices A and C, Combined DRT RRT Summary, Line 10. The DRT deemed tax is reflected in NSA Appendix A, Schedule 5.1, Line 10. The RRT deemed tax is reflected in NSA Appendix C, Schedule 5.2, Line 10.

(g) Energy Credit Charges

In the Application, DERS applied for a DRT revenue requirement that included energy-related credit charges of $0.3 million for each of 2020, 2021 and 2022 (paragraph 135 of section 5.5.5 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 2). Instead, the Parties agree that the Commission should approve DERS' DRT revenue requirement based on energy-related credit charges of $0.2 million for 2020; $0.3 million for 2021; and $0.2 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 2. The DRT energy credit charges is reflected in NSA Appendix A, Schedule 5.1, Line 2.

(h) Non-Energy Credit Charges

In the Application, DERS applied for combined DRT and RRT revenue requirements that included non-energy related credit charges of $0.9 million for 2020; $0.9 million for 2021; and $1.0 million for 2022 (starting at paragraph 136 of section 5.5.5 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 11). Instead, the Parties agree that the Commission should approve DERS' revenue requirements based on zero non-energy related credit charges for the Test Period as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 11.

(i) Hearing Reserve

In the Application, DERS applied for combined DRT and RRT revenue requirements that included a hearing reserve of $0.1 million for 2020; $0.3 million for 2021; and $0.2 million for 2022 (section 5.5.6 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 12). Instead, the Parties agree that the Commission should approve DERS' revenue requirements based on hearing reserves of $0.1 million for 2020; $0.2 million for 2021; and $0.2 million for 2022, provided the existing deferral account treatment of these costs continues. These amounts are reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 12. The DRT hearing reserve is reflected in NSA Appendix A, Schedule 5.1, Line 12. The RRT hearing reserve is reflected in NSA Appendix C, Schedule 5.2, Line 12.

(j) Bad Debt Expense and Late Payment Charge Revenue

(1) Bad Debt Expense

In the Application, DERS applied for combined DRT and RRT revenue requirements that included bad debt expenses of $22.6 million for 2020; $32.7 million for 2021; and $26.0 million for 2022 (section 5.5.7 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Lines 4 and 13). Instead, the Parties agree that for 2020 the Commission should approve DERS' actual combined DRT and RRT bad debt expense of $17.8 million on a final basis. The Parties further agree that for 2021 and 2022, the Commission should approve (i) the Bad Debt Deferral Account described in subparagraph (3) below, and (ii) the forecast DRT and RRT bad debt expense of $18.6 million for 2021, and $14.6 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Lines 4 and 13. The DRT bad debt expense is reflected in NSA Appendix A, Schedule 5.1, Lines 4 and 13. The RRT bad debt expense is reflected in NSA Appendix C, Schedule 5.2, Lines 4 and 13.

(2) Late Payment Charge Revenue

In the Application, DERS applied for combined DRT and RRT revenue requirements that included late payment charge revenue of $3.3 million for 2020, $5.6 million for 2021, and $5.6 million for 2022 (section 5.5.8 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Lines 5 and 14). Instead, the Parties agree that for 2020 the Commission should approve DERS' actual combined DRT and RRT late payment charge revenue of $2.8 million on a final basis. The Parties further agree that for 2021 and 2022 the Commission should approve (i) the LPC Deferral Account described in subparagraph (4) below, and (ii) the forecast DRT and RRT late payment charge revenue of $6.7 million for 2021, and $6.3 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Lines 5 and 14. The DRT late payment charge revenue is reflected in NSA Appendix A, Schedule 5.1, Lines 6 and 14. The RRT late payment charge revenue is reflected in NSA Appendix C, Schedule 5.2, Lines 5 and 14.

(3) Bad Debt Deferral Account

If actual bad debt expense in either of 2021 and 2022 is lower than the agreed-upon forecasts for 2021 and 2022, above, 75% of the difference, for each year, will be deferred to the Bad Debt Deferral Account, to the credit of customers.

If actual bad debt expense in either of 2021 and 2022 is greater than the agreed-upon forecasts for 2021 and 2022, above, 100% of the difference, for each year, will be deferred to the Bad Debt Deferral Account, to the account of customers, up to threshold amounts of $25,072,500 for 2021 and $21,062,000 for 2022.

If the actual bad debt expense in either of 2021 and 2022 is greater than the threshold amounts of $25,072,500 for 2021 and $21,062,000 for 2022, then:

- $6,500,000 and $6,500,000, in regard to 2021 and 2022, respectively, will be deferred to the Bad Debt Deferral Account to the account of customers; and

- 50% of the difference between actual bad debt expense and $25,072,500 for 2021, and $21,062,000 for 2022, will be deferred to the Bad Debt Deferral Account, to the account of customers.

Appendix E provides an interactive spreadsheet that illustrates how the Bad Debt Deferral Account will work.

(4) LPC Deferral Account

Any difference between actual 2021 and 2022 late payment charge revenues and the forecasts described in subparagraph (2) above will be deferred to the LPC Deferral Account. Appendix E provides an interactive spreadsheet that illustrates how the LPC Deferral Account will work.

(5) Interest on Combined Deferral Account Balances

DERS will sum the balances in the Bad Debt Deferral Account and the LPC Deferral Account for interest purposes. Any net balance in excess of $5 million as at January 1, 2023 will accrue interest at the applicable rate specified in AUC Rule 23, to the credit of either DERS or its customers as the case may be. In any event, no interest will accrue prior to January 1, 2023.

(6) Disposition of Combined Deferral Account Balances

DERS will apply for the disposition of the net balance of the Bad Debt Deferral Account and the LPC Deferral Account, including interest in accordance with subparagraph (5), above, if any, whether it is to the account of customers or the credit of customers, in its next non-energy rate application for the test period starting 2023, or in a stand-alone application. In either case, the disposition applied for by DERS will be based on 2021 and 2022 actuals. The application will propose an allocation of the net balance between RRT and DRT. One combined rider for the Bad Debt Deferral and LPC Deferral will be determined for DRT and RRT customers' bills, reflecting the disposition of the net balance of the two deferral accounts. Parties may make submissions in the applicable proceeding regarding the period of time over which the deferral account balances will be collected/refunded, as the case may be, recognizing the need to minimize intergenerational inequities amongst customers.

(k) Revenue Offsets

In the Application, DERS applied for revenue requirements that included revenue offsets of $0.2 million for 2020, $0.05 million for 2021, and $0.05 million for 2022 (section 5.5.9 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Lines 15). Instead, the Parties agree that the Commission should approve revenue offsets of $0.4 million for 2020, $0.05 million for 2021, and $0.05 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 15.

The DRT revenue offsets amount is reflected in NSA Appendix A, Schedule 5.1, Line 15. The RRT revenue offsets amount is reflected in NSA Appendix C, Schedule 5.2, Line 15.

(l) Unknown Customer Costs

In the Application, DERS applied for combined DRT and RRT revenue requirements that included unknown customer costs of $1.5 million for 2020, $2.0 million for 2021, and $2.0 million for 2022 (section 5.5.10 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 16). Instead, the Parties agree that the Commission should approve unknown customer costs of $1.3 million for 2020, $1.6 million for 2021, and $1.7 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 16. The DRT unknown customer cost is reflected in NSA Appendix A, Schedule 5.1, Line 16. The RRT unknown customer cost is reflected in NSA Appendix C, Schedule 5.2, Line 16.

(m) Labour Costs

In the Application, DERS applied for combined DRT and RRT revenue requirements that included labour costs of $7.0 million for 2020, $7.9 million for 2021, and $8.1 for 2022 (section 5.5.11 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Lines 1 and 17). The Parties agree that the Commission should approve labour costs of $6.3 million for 2020, $7.5 million for 2021, and $7.9 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Lines 1 and 17. The DRT labour cost is reflected in NSA Appendix A, Schedule 5.1, Lines 1 and 17. The RRT labour cost is reflected in NSA Appendix C, Schedule 5.2, Line 17. For clarity, the Parties have agreed to a total labour cost for each of 2020, 2021 and 2022. DERS has populated Schedules 5.1.9 and 5.2.9 having regard to the agreed to total labour cost.

(n) Amortization of Capital

In the Application, DERS applied for combined DRT and RRT revenue requirements that included amortization of capital of $0.5 million for 2020, $0.4 million for 2021, and $0.3 million for 2022 (section 5.5.12 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 18). The Parties agree that the Commission should approve amortization of capital of $0.5 million for 2020, $0.4 million for 2021, and $0.3 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 18. The DRT amortization of capital cost is reflected in NSA Appendix A, Schedule 5.1, Line 18. The RRT amortization of capital cost is reflected in NSA Appendix C, Schedule 5.2, Line 18.

(o) Customer Information

In the Application, DERS applied for combined DRT and RRT revenue requirements that included customer information costs of $0.1 million for 2020, $0.1 million for 2021, and $0.1 million for 2022 (section 5.5.13 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 19). Instead, the Parties agree that the

Commission should approve customer information costs of $0.1 million for 2020, $0.1 million for 2021, and $0.1 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 19. The DRT customer information cost is reflected in NSA Appendix A, Schedule 5.1, Line 19. The RRT customer information cost is reflected in NSA Appendix C, Schedule 5.2, Line 19.

(p) Other Administration

In the Application, DERS applied for combined DRT and RRT revenue requirements that included other administration costs of $1.7 million for 2020, $1.3 million for 2021, and $1.3 million for 2022 (section 5.5.14 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 20). Instead, the Parties agree that the Commission should approve other administration costs of $1.0 million for 2020, $1.0 million for 2021, and $1.0 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 20. The DRT other administration cost is reflected in NSA Appendix A, Schedule 5.1, Line 20. The RRT other administration cost is reflected in NSA Appendix C, Schedule 5.2, Line 20.

(q) Corporate Services Costs

In the Application, DERS applied for combined DRT and RRT revenue requirements that included corporate services costs of $3.7 million for 2020, $3.8 million for 2021, and $3.9 million for 2022 (section 5.5.15 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 21). Instead, the Parties agree that the Commission should approve corporate services costs of $3.6 million for 2020, $3.5 million for 2021, and $3.6 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 21. The DRT corporate services cost is reflected in NSA Appendix A, Schedule 5.1, Line 21. The RRT corporate services cost is reflected in NSA Appendix C, Schedule 5.2, Line 21.

(r) DRT Return Margin

In the Application, DERS applied for a DRT revenue requirement that included a DRT return margin of $4.8 million for 2020, $4.5 million for 2021, and $4.4 million for 2022, (section 6.1 of the Application and Exhibits 26207-X0003 and -X0004, Combined DRT RRT Summary, Line 25). Instead, the Parties agree that the Commission should approve DRT return margin of $4.7 million for 2020, $4.5 million for 2021, and $4.4 million for 2022 as reflected in NSA Appendices A and C, Combined DRT RRT Summary, Line 25. The DRT return margin is reflected in NSA Appendix A, Schedule 5.1, Line 25.

2.2 Rate Schedules

(a) DRT Rate Schedules

In the Application, DERS applied for approval of DRT rates for the Test Period described in the rate schedules comprising Attachments 34 to 39 of the Application. Instead, the

Parties agree that the Commission should approve the DRT rates described in NSA Appendix B.

(b) RRT Rate Schedules

In the Application, DERS applied for approval of RRT rates described in the rate schedules comprising Attachments 40 to 45 of the Application. Instead, the Parties agree that the Commission should approve the RRT rates described in NSA Appendix D.

2.3 Orders Requested from the Commission

For certainty, the Parties agree that the Commission should grant one or more orders:

(a) Approving this Agreement in its entirety; and

(b) Granting the relief sought by DERS in the Application except as modified by this Agreement including Sections 2.1 and 2.2 of this Agreement.

2.4 Regulated and Competitive Split in Future Rate Applications

In its 2023 non-energy rate application, and thereafter, DERS shall apply for, and the UCA and the CCA shall support, revenue requirements that are based on a regulated-to-competitive customer ratio based on the most recently available MSA Data.

2.5 Semi-Annual Bad Debt and Late Payment Charge Revenue Report (“Report”)

(a) For 2021 and 2022, DERS shall provide semi-annual reports to the UCA and the CCA on the accrued bad debt expense and late payment charge revenue received during the reporting period, in the form attached as NSA Appendix F.

(b) The reporting periods and delivery schedule for each Report shall be as follows:

(i) DERS shall provide the first Report for 2021 on or before August 1, 2021 covering the period from January 1 to June 30, 2021;

(ii) DERS shall provide the second Report for 2021 on or before February 1, 2022, covering the period from July 1 to December 31, 2021;

(iii) DERS shall provide the first Report for 2022 on or before August 1, 2022 covering the period from January 1 to June 30, 2022; and

(iv) DERS shall provide the second Report for 2022 on or before February 1, 2023, covering the period from July 1 to December 31, 2022.

2.6 Reporting on material changes to collection practices

For 2021 and 2022, DERS will provide the UCA and the CCA timely notification related to material changes to collection practices.

2.7 2021 and 2022 Annual Stakeholder Session

DERS will hold one (1) stakeholder session on bad debt and late payment charges in 2021, and one (1) in 2022, in early August of each year.

2.8 Re-Opener

Any of the Parties may apply to the Commission to re-open and amend the bad debt or late payment charge revenue provisions of this Agreement, set out in paragraph 2.1(j) of this Agreement, and the resultant revenue requirements, if in their opinion a change in law or in government policies or rules, (including regulations, ministerial orders, AUC decisions, orders, guidelines, directives, or AUC or Independent System Operator Rules) materially undermines the risk /reward allocation inherent in the Bad Debt Deferral Account and LPC Deferral Account provisions of this Agreement. For greater clarity, it is not the intent of Parties for DERS to receive upside sharing or incur losses under the proposed deferral account structure where material changes in bad debt result from a change in law or in government policies or rules.

Such an application will be subject to the approval of the Commission. An application made under this section must include, at a minimum, a detailed description of the change giving rise to the re-opening request and the specific modifications to the Agreement that the Party requests that the Commission approves to address the change. The Party that brings any such application shall provide the other two parties with at least two weeks notice, and make good-faith efforts to explain the issue with a view to bringing an application to the Commission that is supported by all Parties. The Parties agree that any application to amend the bad debt or late payment charge revenue provisions of this Agreement will not be considered to be an application for review and variance and will not be subject to the requirements of AUC Rule 016 or any successor or replacement rule.

2.9 Notice of Response to Exhibit 26207-X0088

DERS agrees to provide the UCA and the CCA with timely notice of:

i. any response(s) received by DERS to the letter to the Minister of Finance filed as Exhibit 26207-X0088; and,
ii. any changes to the policy or legislation governing federal fuel charges, as addressed in the letter filed as Exhibit 26207-X0088.

2.10 Consultation on Gathering Customer Information

DERS shall consult with the UCA and the CCA on the development of survey questions for exit studies conducted by DERS as part of its customer information gathering initiatives with at least two weeks notice prior to the commencement of the 2021 and 2022 exit study initiatives.

2.11 Costs of the CCA

(a) Within 60 days following the receipt of invoices from the CCA, DERS will pay the CCA, on a refundable basis, the reasonable costs and expenses incurred by it in connection with retaining consultants and counsel in relation to the Application and the related negotiated settlement process to and including the point of approval of the Agreement. In the event of any difference between the costs paid to the CCA by DERS and the portion of DERS' cost claim (for recovery of costs related to this Application and negotiated settlement process including the CCA costs) associated with the CCA and approved by the AUC, the CCA will refund to DERS any amount by which DERS' approved cost claims differ from the amounts paid to the CCA by DERS within 60 days of the date of the AUC's decision approving DERS' cost claim.

(b) DERS will, in any event, pay to the CCA the amount of costs and expenses incurred by the CCA and approved by the AUC in connection with the Agreement and the related negotiated settlement process within 60 days of the date of the AUC's decision approving a CCA cost claim.

ARTICLE 3
CONFIDENTIALITY AND PRIVILEGE

3.1 Without Prejudice

The negotiated settlement reflected in this Agreement is a compromise and was reached as a result of the desire of the Parties to avoid the significant resources and uncertainty associated with a litigated process. This Agreement is without prejudice to the positions that the Parties may take in other mediations, negotiations, or regulatory proceedings.

3.2 Confidentiality

All discussions among the Parties during the Mediation are privileged and confidential and, except as set out in the Agreement or in DERS IR responses filed on the record of the Proceeding, no matter discussed or information provided during the Mediation settlement process may be disclosed to any person or to the AUC without the express written consent of all the Parties.

ARTICLE 4
Rule 018 Requirements

4.1 Notice

DERS confirms that proper notice of the Mediation was provided to all interested parties in the Proceeding by way of the AUC's letter, dated January 29, 2021 (Exhibit 26207-X0069), and by way of the AUC's letter, dated February 3, 2021 (Exhibit 26207-X0078), both of which were filed on the AUC's e-Filing system for the Proceeding. DERS further confirms that proper notice of its forthcoming application for approval of this Agreement will be effected in accordance with the AUC's directions and practice, including the notice provisions of AUC Rule 001: *Rules of Practice* [AUC Rule 018, section 3 and section 6(3)(a)].

4.2 Relevant Information

Each Party represents that it has not withheld information relevant to the Application [AUC Rule 018, section 6(1)]. Further, DERS represents that all information provided to the CCA and the UCA during the Mediation was true and accurate, to the best of DERS' knowledge and belief.

4.3 All Issues Resolved Except RRT Energy Return Margin

(a) In accordance with the AUC's direction that the issue was beyond the scope of the Proceeding (Exhibit 26207-X0069), the Mediation settlement process did not address the RRT energy return margin that DERS applied for in the Application.

(b) Other than the RRT energy return margin component of the Application, the Parties confirm that all in-scope components of the Application are resolved by this Agreement [AUC Rule 018, section 6(3(c)]; all in-scope issues were resolved unanimously [AUC Rule 018, section 6(3(d)]; and that there are no outstanding in-scope issues as between the Parties [AUC Rule 018, section 6(3(g)].

4.4 Rates

The DRT rates that will result from the Agreement are described Appendix B and the RRT rates that will result from the Agreement are described in Appendix D [AUC Rule 018, section 6(3(e)].

ARTICLE 5
APPROVAL BY THE AUC

5.1 Approval Contingent Upon

This Agreement will be of no force and effect unless the AUC approves this Agreement in its entirety in accordance with Section 28.6 of the GUA and Section 135 of the EUA.

IN WITNESS WHEREOF, the Parties have duly executed this Agreement as of the date set out above.

DIRECT ENERGY REGULATED SERVICES

By: ______________________________

Name: Tanis Kozak

Title: Vice President & General Manager

CONSUMERS' COALITION OF ALBERTA

By: ______________________________

Name:

Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

By: ______________________________

Name:

Title:

By: ________________________________

Name:

Title:

CONSUMERS' COALITION OF ALBERTA

By: ________________________________

Name:

Title:

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

By: C. W. Hunt

Name: Chris Hunt

Title: Executive Director & Advocate

By: ______________________________

Name:

Title:

CONSUMERS' COALITION OF ALBERTA

By: ______________________________

Name: James A. Wachowich ID26207

Title: Legal counsel to the CCA signed by direction of the client

OFFICE OF THE UTILITIES CONSUMER ADVOCATE

By: ______________________________

Name:

Title:

DIRECT ENERGY REGULATED SERVICES

2021 FINAL RATE SCHEDULES

FOR DRT SERVICE IN ATCO GAS NORTH SERVICE TERRITORY

EFFECTIVE July 1, 2021

Direct Energy Regulated Services.

DIRECT ENERGY REGULATED SERVICES (DERS) RATE G1 – LOW AND MID USE DELIVERY SERVICE ATCO GAS NORTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) Low Use Delivery Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.294 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AGPLN Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus		
	AGPLN Delivery – Variable Charge including Riders	

Minimum Monthly Charge:	**Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G3 – HIGH USE SERVICE
ATCO GAS NORTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) High Use Delivery Service.

<u>CHARGES:</u>

Fixed Charges:

	DERS Customer Charge	**$0.490 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AGPLN Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus		
	AGPLN Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider "F" GAS COST FLOW-THROUGH
ATCO GAS NORTH SERVICE TERRITORY

To be applied to all energy sold to customers served under Rates Low Use Delivery Service, Mid Use Delivery Service, High Use Delivery Service.

CHARGES:

Gas Cost Flow-through Rate:

For customers served by ATCO Gas North:

For the Period TBD	**$TBD per GJ**

DIRECT ENERGY REGULATED SERVICES (DERS) PRICE SCHEDULE

1. Connection Charge (Section 4.1)	Amount of any applicable ATCO Gas charge
2. Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Gas charge
3. Meter Reads, Off-Cycle Meter Reads or Meter Disputes	Amount of any applicable ATCO Gas charge
4. Meter Handling or Meter Relocations	Amount of any applicable ATCO Gas charge
5. Customer Usage Information	Amount of any applicable ATCO Gas charge
6. Dishonored Cheque	$25.00
7. Late Payment Fee	1.5% per month of the amount outstanding
8. Fee for Credit Check	Amount equal to the cost of the credit check

DIRECT ENERGY REGULATED SERVICES
(DERS)
GENERAL CONDITIONS
ATCO GAS NORTH SERVICE TERRITORY

1. Approval of the Alberta Utilities Commission (AUC) All Rates

and Riders of DERS are subject to approval by the AUC.

2. Terms and Conditions of Service

Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AUC.

3. Other ATCO Gas and Pipelines Ltd. (AGPL) Charges

In addition to the AGPL charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all AGPL charges or riders approved by the AUC.

Direct Energy Regulated Services®

DIRECT ENERGY REGULATED SERVICES

2021 FINAL RATE SCHEDULES

FOR DRT SERVICE IN ATCO GAS SOUTH SERVICE TERRITORY

EFFECTIVE July 1, 2021

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G1 – LOW AND MID USE DELIVERY SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Low Use Delivery Service

<u>CHARGES:</u>

Fixed Charges:

	DERS Customer Charge	**$0.294 per Day**
plus	DERS – Riders (as applicable)	
plus	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective July 1, 2021
Rate G3 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G3 – LARGE USE SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) High Use Delivery Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.490 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus		
	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge:	**Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G5 – IRRIGATION DELIVERY SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Irrigation Delivery Service

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.244 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider “F”**
plus		
	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider "F" GAS COST FLOW-THROUGH
ATCO GAS SOUTH SERVICE TERRITORY

To be applied to all energy sold to customers served under Rates Low Use Delivery Service, Mid Use Delivery Service, High Use Delivery Service and Irrigation Delivery Service

CHARGES:

Gas Cost Flow-through Rate:

For customers served by ATCO Gas South:

For the Period TBD	**$TBD per GJ**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES (DERS) PRICE SCHEDULE

1. Connection Charge (Section 4.1)	Amount of any applicable ATCO Gas charge
2. Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Gas charge
3. Meter Reads, Off-Cycle Meter Reads or Meter Disputes	Amount of any applicable ATCO Gas charge
4. Meter Handling or Meter Relocations	Amount of any applicable ATCO Gas charge
5. Customer Usage Information	Amount of any applicable ATCO Gas charge
6. Dishonored Cheque	$ 25.00
7. Late Payment Fee	1.5% per month of the amount outstanding
8. Fee for Credit Check	Amount equal to the cost of the credit check

DIRECT ENERGY REGULATED SERVICES
(DERS)
GENERAL CONDITIONS
ATCO GAS SOUTH SERVICE TERRITORY

1. Approval of the Alberta Utilities Commission (AUC) All Rates

and Riders of DERS are subject to approval by the AUC.

2. Terms and Conditions of Service

Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AUC.

3. Other ATCO Gas and Pipelines Ltd. (AGPL) Charges

In addition to the AGPL charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all AGPL charges or riders approved by the AUC.

DIRECT ENERGY REGULATED SERVICES

2022 FINAL RATE SCHEDULES

FOR DRT SERVICE IN ATCO GAS NORTH SERVICE TERRITORY

EFFECTIVE JANUARY 1, 2022

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G1 – LOW AND MID USE DELIVERY SERVICE
ATCO GAS NORTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) Low Use Delivery Service.

<u>CHARGES:</u>

Fixed Charges:

	DERS Customer Charge	**$0.294 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AGPLN Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus		
	AGPLN Delivery – Variable Charge including Riders	

Minimum Monthly Charge:	**Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rate G3 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES (DERS)
RATE G3 – HIGH USE SERVICE
ATCO GAS NORTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. North (AGPLN) High Use Delivery Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.507 per Day**
plus	DERS – Riders (as applicable)	
plus	AGPLN Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider “F”**
plus	AGPLN Delivery – Variable Charge including Riders	

Minimum Monthly Charge:	**Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rate "F" Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider "F" GAS COST FLOW-THROUGH
ATCO GAS NORTH SERVICE TERRITORY

To be applied to all energy sold to customers served under Rates Low Use Delivery Service, Mid Use Delivery Service, High Use Delivery Service.

CHARGES:

Gas Cost Flow-through Rate:

For customers served by ATCO Gas North:

For the Period TBD	**$TBD per GJ**

DIRECT ENERGY REGULATED SERVICES
(DERS)
PRICE SCHEDULE

1. Connection Charge (Section 4.1)	Amount of any applicable ATCO Gas charge
2. Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Gas charge
3. Meter Reads, Off-Cycle Meter Reads or Meter Disputes	Amount of any applicable ATCO Gas charge
4. Meter Handling or Meter Relocations	Amount of any applicable ATCO Gas charge
5. Customer Usage Information	Amount of any applicable ATCO Gas charge
6. Dishonored Cheque	$25.00
7. Late Payment Fee	1.5% per month of the amount outstanding
8. Fee for Credit Check	Amount equal to the cost of the credit check

Approved by Decision 26207-D01-2021
Effective January 1, 2022
General Conditions Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
GENERAL CONDITIONS
ATCO GAS NORTH SERVICE TERRITORY

1. **Approval of the Alberta Utilities Commission (AUC)** All Rates

   and Riders of DERS are subject to approval by the AUC.

2. **Terms and Conditions of Service**

   Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AUC.

3. **Other ATCO Gas and Pipelines Ltd. (AGPL) Charges**

   In addition to the AGPL charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all AGPL charges or riders approved by the AUC.

DIRECT ENERGY REGULATED SERVICES

2022 FINAL RATE SCHEDULES

FOR DRT SERVICE IN ATCO GAS SOUTH SERVICE TERRITORY

EFFECTIVE JANUARY 1, 2022

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G1 – LOW AND MID USE DELIVERY SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Low Use Delivery Service

<u>CHARGES:</u>

Fixed Charges:

	DERS Customer Charge	**$0.294 per Day**
plus	DERS – Riders (as applicable)	
plus	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider “F”**
plus	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rate G3 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G3 – LARGE USE SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) High Use Delivery Service.

<u>CHARGES:</u>

Fixed Charges:

	DERS Customer Charge	**$0.507 per Day**
plus	DERS – Riders (as applicable)	
plus	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider “F”**
plus	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rate G5 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE G5 – IRRIGATION DELIVERY SERVICE
ATCO GAS SOUTH SERVICE TERRITORY

Available to all customers eligible for ATCO Gas and Pipelines Ltd. South (AGPLS) Irrigation Delivery Service

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.244 per Day**
plus	DERS – Riders (as applicable)	
plus	AGPLS Delivery – Fixed Charge including Riders	

Variable Charges:

	DERS Gas Cost Flow-through Rate	**Rider "F"**
plus	AGPLS Delivery – Variable Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rider “F” Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider "F" GAS COST FLOW-THROUGH
ATCO GAS SOUTH SERVICE TERRITORY

To be applied to all energy sold to customers served under Rates Low Use Delivery Service, Mid Use Delivery Service, High Use Delivery Service and Irrigation Delivery Service

CHARGES:

Gas Cost Flow-through Rate:

For customers served by ATCO Gas South:

For the Period TBD	**$TBD per GJ**

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Price Schedule Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
PRICE SCHEDULE

1. Connection Charge (Section 4.1)	Amount of any applicable ATCO Gas charge
2. Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Gas charge
3. Meter Reads, Off-Cycle Meter Reads or Meter Disputes	Amount of any applicable ATCO Gas charge
4. Meter Handling or Meter Relocations	Amount of any applicable ATCO Gas charge
5. Customer Usage Information	Amount of any applicable ATCO Gas charge
6. Dishonored Cheque	$ 25.00
7. Late Payment Fee	1.5% per month of the amount outstanding
8. Fee for Credit Check	Amount equal to the cost of the credit check

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES (DERS) GENERAL CONDITIONS ATCO GAS SOUTH SERVICE TERRITORY

1. **Approval of the Alberta Utilities Commission (AUC)** All Rates

   and Riders of DERS are subject to approval by the AUC.

2. **Terms and Conditions of Service**

   Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Default Rate Service of DERS as approved by the AUC.

3. **Other ATCO Gas and Pipelines Ltd. (AGPL) Charges**

   In addition to the AGPL charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all AGPL charges or riders approved by the AUC.

DIRECT ENERGY REGULATED SERVICES

2021 FINAL RATE SCHEDULES

FOR ELECTRICITY RRT SERVICE

EFFECTIVE July 1, 2021

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective July 1, 2021
Rate E1 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E1 – RESIDENTIAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D11 – Standard Residential Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.475 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery – Customer Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E1	**Rider "P"**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E2 – SMALL GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D21 Standard Small General Service and Price Schedule D22 Small General Service – Energy Only

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge	**$0.518 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E2	**Rider "P"**
plus		
	AE Delivery - Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES (DERS) RATE E3 – LARGE GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D31 Large General Service/Industrial, Price Schedule T31 Large General Service/Industrial Transmission Connected, and Price Schedule D32 Generator Interconnection and Standby Power.

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge	**$0.818 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E3	**Rider "P"**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES (DERS) RATE E4 – OILFIELD SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D41 Small Oilfield and Pumping Power.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.526 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E4	**Rider “P”**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

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Effective July 1, 2021
Rate E5 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E5 – FARM SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D56 Farm Service.

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge	**$0.506 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery – Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E5	**Rider “P”**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Approved by Decision 26207-D01-2021
Effective July 1, 2021
Rate E6 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E6 – LIGHTING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D61 Street Lighting Service and Price Schedule D63 Private Lighting Service.

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge*	**$0.239 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

DERS Energy Charge Applicable to Rate E6	**Rider “P”**

Minimum Monthly Charge: **Fixed Charges**

* The Customer Charge applies per Site

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective July 1, 2021
Rate E7 Page 1 of 1

DIRECT ENERGY REGULATED SERVICES (DERS)
RATE E7 – IRRIGATION PUMPING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D25 Irrigation Pumping Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.542 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E7	**Rider "P"**
plus		
	AE Delivery - Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider “P” ENERGY CHARGE SCHEDULE

To be applied to all energy sold to customers served under Rates E1, E2, E3, E4, E5, E6 and E7.

Energy Charge Schedule:

Energy Charge Applicable to Rate **E1**	**$TBD per kWh**
Energy Charge Applicable to Rate **E2**	**$TBD per kWh**
Energy Charge Applicable to Rate **E3**	**$TBD per kWh**
Energy Charge Applicable to Rate **E4**	**$TBD per kWh**
Energy Charge Applicable to Rate **E5**	**$TBD per kWh**
Energy Charge Applicable to Rate **E6**	**$TBD per kWh**
Energy Charge Applicable to Rate **E7**	**$TBD per kWh**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES (DERS) PRICE SCHEDULE

1.	Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Electric charge
2.	Meter Reads, Supplementary Meter Reads or Meter Disputes	Amount of any applicable ATCO Electric charge
3.	Interval Meter Usage Data	Amount of any applicable ATCO Electric charge
4.	Dishonoured Cheque	$25.00
5.	Late Payment Fee	1.5% per month of the amount outstanding
6.	Fee for Credit Check	Amount equal to the cost of the credit check

DIRECT ENERGY REGULATED SERVICES (DERS) GENERAL CONDITIONS

1. Approval of the Alberta Utilities Commission (AUC)

All Rates and Riders of DERS are subject to approval by the AUC.

2. Terms and Conditions of Service

Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Regulated Rate Service of DERS as approved by the AUC.

3. Other ATCO Electric Ltd. (AE) Charges

In addition to the AE charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all other AE charges and Riders as well as any Power Factor Corrections and Price Options, levied by AE and approved by the AUC.

DIRECT ENERGY REGULATED SERVICES

2022 FINAL RATE SCHEDULES

FOR ELECTRICITY RRT SERVICE

EFFECTIVE JANUARY 1, 2022

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E1 – RESIDENTIAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D11 – Standard Residential Service.

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge	**$0.460 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery – Customer Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E1	**Rider "P"**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge:	**Fixed Charges**

DIRECT ENERGY REGULATED SERVICES (DERS) RATE E2 – SMALL GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D21 Standard Small General Service and Price Schedule D22 Small General Service – Energy Only

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.488 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E2	**Rider "P"**
plus		
	AE Delivery - Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E3 – LARGE GENERAL SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D31 Large General Service/Industrial, Price Schedule T31 Large General Service/Industrial Transmission Connected, and Price Schedule D32 Generator Interconnection and Standby Power.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.718 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E3	**Rider "P"**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E4 – OILFIELD SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D41 Small Oilfield and Pumping Power.

<u>CHARGES</u>:

Fixed Charges:

DERS Customer Charge **$0.491 per Day**

plus

DERS – Riders (as applicable)

plus

AE Delivery - Customer Charge including Riders

plus

AE Delivery - Demand Charge including Riders

Variable Charges:

DERS Energy Charge Applicable to Rate E4 **Rider "P"**

plus

AE Delivery – Energy Charge including Riders

Minimum Monthly Charge: **Fixed Charges**

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E5 – FARM SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D56 Farm Service.

<u>CHARGES</u>:

Fixed Charges:

	DERS Customer Charge	**$0.484 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery – Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E5	**Rider “P”**
plus		
	AE Delivery – Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E6 – LIGHTING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D61 Street Lighting Service and Price Schedule D63 Private Lighting Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge*	**$0.242 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE Delivery - Demand Charge including Riders	

Variable Charges:

DERS Energy Charge Applicable to Rate E6	**Rider "P"**

Minimum Monthly Charge:	**Fixed Charges**

* The Customer Charge applies per Site

DIRECT ENERGY REGULATED SERVICES
(DERS)
RATE E7 – IRRIGATION PUMPING SERVICE

Available to all customers eligible for ATCO Electric Ltd. (AE) Price Schedule D25 Irrigation Pumping Service.

CHARGES:

Fixed Charges:

	DERS Customer Charge	**$0.506 per Day**
plus		
	DERS – Riders (as applicable)	
plus		
	AE Delivery - Customer Charge including Riders	
plus		
	AE - Demand Charge including Riders	

Variable Charges:

	DERS Energy Charge Applicable to Rate E7	**Rider “P”**
plus		
	AE Delivery - Energy Charge including Riders	

Minimum Monthly Charge: **Fixed Charges**

Direct Energy Regulated Services

Approved by Decision 26207-D01-2021
Effective January 1, 2022
Rider "P" Page 1 of 1

DIRECT ENERGY REGULATED SERVICES
(DERS)
Rider "P" ENERGY CHARGE SCHEDULE

To be applied to all energy sold to customers served under Rates E1, E2, E3, E4, E5, E6 and E7.

Energy Charge Schedule:

Energy Charge Applicable to Rate **E1**	**$TBD per kWh**
Energy Charge Applicable to Rate **E2**	**$TBD per kWh**
Energy Charge Applicable to Rate **E3**	**$TBD per kWh**
Energy Charge Applicable to Rate **E4**	**$TBD per kWh**
Energy Charge Applicable to Rate **E5**	**$TBD per kWh**
Energy Charge Applicable to Rate **E6**	**$TBD per kWh**
Energy Charge Applicable to Rate **E7**	**$TBD per kWh**

Direct Energy Regulated Services

DIRECT ENERGY REGULATED SERVICES
(DERS)
PRICE SCHEDULE

1.	Reconnection Charge (Section 8.7)	Amount of any applicable ATCO Electric charge
2.	Meter Reads, Supplementary Meter Reads or Meter Disputes	Amount of any applicable ATCO Electric charge
3.	Interval Meter Usage Data	Amount of any applicable ATCO Electric charge
4.	Dishonoured Cheque	$25.00
5.	Late Payment Fee	1.5% per month of the amount outstanding
6.	Fee for Credit Check	Amount equal to the cost of the credit check

DIRECT ENERGY REGULATED SERVICES (DERS) GENERAL CONDITIONS

1. Approval of the Alberta Utilities Commission (AUC)

All Rates and Riders of DERS are subject to approval by the AUC.

2. Terms and Conditions of Service

Service under all DERS' Rates and Riders are subject to the Terms and Conditions of Regulated Rate Service of DERS as approved by the AUC.

3. Other ATCO Electric Ltd. (AE) Charges

In addition to the AE charges specifically identified in these Rate Schedules, customer bills will include, as applicable, all other AE charges and Riders as well as any Power Factor Corrections and Price Options, levied by AE and approved by the AUC.