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**FARRIS**

January 23, 2026

BY ELECTRONIC FILING

British Columbia Utilities Commission  
Suite 410, 900 Howe Street  
Vancouver, BC Canada  
V6Z 2N3

**Attention: Registrar**

Dear Sir/Madam:

**Re: Application for Reconsideration and Variance of Order G-270-25 on Pacific Northern Gas Ltd.'s 2025 to 2027 Revenue Requirements and Stay of Proceeding**

We are counsel for Pacific Northern Gas Ltd. (**PNG**).

Pursuant to section 99 of the *Utilities Commission Act*, please find enclosed for filing the application (the **Reconsideration Application**) of PNG for reconsideration and variance of British Columbia Utilities Commission (**BCUC**) Order G-270-25, dated November 24, 2025, on PNG's 2025 to 2027 Revenue Requirements. PNG also seeks a stay of proceeding.

Yours truly,

FARRIS LLP

Per:



Erica C. Miller

ECM/  
Enclosures  
c.c.: Client

**FARRIS LLP**

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# BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the *Utilities Commission Act*, RSBC 1996 c 473

and

Pacific Northern Gas Ltd. Application for Reconsideration and Variance  
of British Columbia Utilities Commission Order G-270-25  
on the Pacific Northern Gas Ltd. PNG-West 2025 to 2027 Revenue Requirements  
and Stay of Proceedings

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## PACIFIC NORTHERN GAS LTD.

### RECONSIDERATION APPLICATION & STAY OF PROCEEDINGS

January 23, 2026

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#### **Pacific Northern Gas Ltd.**

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Vancouver, BC V6C 3K4

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## INTRODUCTION

1. Pacific Northern Gas Ltd. (**PNG** or the **Company**) files this application (the **Reconsideration Application**) pursuant to section 99 of the *Utilities Commission Act* (the **UCA**) for reconsideration and variance of British Columbia Utilities Commission (**BCUC** or the **Commission**) Order and Decision G-270-25, dated November 24, 2025 (the **Decision**), regarding PNG's 2025 to 2027 Revenue Requirements Application (the **Underlying Application**). Additionally, PNG seeks a stay of the direction in the Decision that it file a compliance filing pursuant to section 32.02 of the Commission's Rules of Practice and Procedure, Order G-192-25 (the **BCUC Rules**), pending the outcome of this Reconsideration Application.
2. PNG seeks the reconsideration and variance of two aspects of the Decision, described next.
3. **First**, PNG seeks reconsideration of the Panel's decision to deny recovery in rates of 50 percent of the forecast integrity management capital expenditures of \$45.15 million over the period of 2025, 2026 and 2027 (the **Test Period**).<sup>1</sup> PNG submits that the Panel erred in fact and/or law in concluding that PNG had not demonstrated a need for the full amount of this integrity-management related spending and that PNG may prioritize work within this reduced expenditure amount while maintaining safe and reliable service at the current system operating pressures, and that the BCUC has set rates that are unjust or unreasonable. Further, new evidence has arisen from the British Columbia Energy Regulator (**BCER**), in response to the Decision, which will have a material bearing on the Decision and supports reconsideration and variance.
4. The Panel's decision to deny recovery of these integrity management expenditures will have a material impact on PNG's customers, the Company, and its system. The integrity expenditures proposed as part of the Underlying Application incorporate activities necessary to meet the threshold for acceptable system sustainment by industry standards, so as to maintain PNG's current operating pressure of 800 psig.<sup>2</sup> There is no spending that could be deferred or avoided without severely diminishing PNG's ability to manage pipeline integrity as a reasonable operator, and materially increasing PNG's safety, reliability, operating and compliance risk. If PNG must reduce its overall spending on its integrity management program by 50 percent, it anticipates that, in the near term, it will need to voluntarily reduce its pipeline operating pressure, as required by industry and engineering standards. If PNG reduces its operating pressure over time, its ability to serve all of its existing customers will be impacted; further, PNG's ability to serve new customers (including prospective LNG and other customers in the North) will also be impacted. A reduction in operating pressure also risks leaving PNG's past investments stranded and threatens its reputation with the BCER, which obligates PNG to proactively identify, assess and mitigate threats to pipeline integrity on an ongoing basis, with a goal towards eventually further increasing operating pressures towards the pipeline Maximum Operating Pressure (**MOP**). Recently, and in response to the Decision, the BCER has suggested that it may implement reductions in pressure if inspection and repair activities are deferred.
5. In the alternative, if PNG performs the integrity management work that it has determined is required in order to safely and reliably operate its system in accordance with its Integrity Management Program (which is a core requirement of PNG's Licence to Operate under the *Energy Resources Activities Act*), this is forecast to cost the full \$45.15 million PNG sought to recover in the Underlying Application. If PNG is denied recovery of 50 percent of these expenditures, as ordered by the Decision, its rates will be unjust and/or unreasonable, and

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<sup>1</sup> Decision, p. 22.

<sup>2</sup> Pounds per square inch gauge (**psig**).

insufficient to yield a fair and reasonable compensation for the service provided by the utility or a fair and reasonable return on the appraised value of its property.<sup>3</sup>

6. As a result, in this Reconsideration Application, PNG seeks to vary the Decision that PNG (a) be denied recovery in rates of 50 percent of the Test Period forecast integrity management capital expenditures of \$45.15 million, and (b) be directed to reflect this adjustment in the Test Period capital expenditures to be filed as part of the compliance filing that PNG is directed to submit to the BCUC, to instead provide that PNG may recover in rates the full amount of the forecast integrity management capital expenditures.
7. **Second**, PNG seeks reconsideration of the Panel's direction that PNG set basic and delivery charges for the Test Period based on a 5-year rate smoothing scenario (as outlined in Panel Information Request (IR) 3.1<sup>4</sup>) and establish a Rate Smoothing deferral account to set the Test Period rates based on this 5-year rate smoothing scenario.<sup>5</sup> PNG submits that the Panel erred in fact and law in concluding that rates ought to be smoothed evenly over 5-years. This results in PNG's recovery being deferred beyond the Test Period, creating significant financial risks for PNG, increasing rates for customers, increasing risk for the shareholder, and resulting in rates that are unjust and/or unreasonable under the UCA. These concerns are exacerbated by the expectation that PNG complete this smoothing approach by using simplifying assumptions that were provided as illustrative only, in order to be as responsive as possible to a Panel IR. In providing this information, PNG emphasized that it could not forecast rates in a future period, and that the assumptions were not reflective of actual facts or forecasts. These assumptions hinder the reliability of PNG's analysis and mean that even minor and likely changes to the assumptions could have a material impact on the outcome of the smoothing. PNG respectfully submits that this is not an appropriate input into setting rates. Further, PNG submits that the Panel exceeded its jurisdiction in making this order, as it requires rate smoothing beyond the current Test Period, either improperly binding a future panel that will consider PNG's next revenue requirements application or leaving PNG in the untenable position of not being able to recover amounts that were deferred beyond the Test Period.
8. The Panel's decision to defer recovery of a sizeable portion of PNG's revenue requirements (approximately \$35 million, or approximately one-third of PNG's total annual revenue requirements), outside the Test Period to 2028 and 2029, clearly has a material and direct impact on PNG. As is described in more detail below, this creates significant financial risk for PNG in terms of significantly reducing cash flow, increasing recovery risk, negatively impacting PNG's credit rating and increasing PNG's cost of borrowing, all of which ultimately comes at a cost to ratepayers. These risks are further amplified by the uncertainty caused by the simplifying assumptions that were necessary to calculate the impacts of a 5-year rate smoothing scenario in response to Panel IR 3.1.<sup>6</sup> Further, the Decision has a material impact in that it results in a substantially higher cumulative rate increase for customers (120.9 percent over 5-years) as compared to the 3-year rate smoothing proposed by PNG over the Test Period (77.2 percent over 3-years), which balances the rate increases within the Test Period while mitigating the significant financial risks.
9. In this Reconsideration Application, PNG seeks to vary the Decision that PNG be directed to (a) set basic and delivery charges for the Test Period based on the 5-year rate smoothing scenario outlined in Panel IR 3.1 (Ex. B-12) as set out in the Decision, (b) provide supporting calculations for the Test Period as part of the compliance filing that PNG is directed to submit

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<sup>3</sup> UCA, s. 59.

<sup>4</sup> Ex. B-12, PNG Response to Panel IR No. 2, IR 3.1.

<sup>5</sup> Decision, Order #1(a) and (b).

<sup>6</sup> Ex. B-12, PNG Response to Panel IR No. 2, IR 3.1.

to the BCUC, (c) establish a Rate Smoothing deferral account to set the Test Period rates based on a 5-year rate smoothing scenario, and (d) address the disposition of the Rate Smoothing deferral account balance as at December 31, 2027, in PNG's next RRA. PNG submits that the Decision ought to be varied to instead implement the three-year rate smoothing proposed in the Application.

10. PNG does not seek reconsideration or variation of Order G-270-25 in any other respect; however, as is returned to below, it does seek further clarification from the BCUC with respect to a direction made regarding updating its Test Period revenue requirements in its compliance filing with respect to net Operating, Maintenance, and Administrative & General (**OMA&G**) expenses.
11. Further, in this Reconsideration Application, PNG seeks a stay of the operation of the Decision, pending the outcome of this reconsideration. Specifically, in the Decision, PNG was directed to file a compliance filing with the BCUC by January 14, 2026, which was to include revised regulatory schedules, updated tariff pages reflecting the permanent approvals and supporting calculations in a working Excel spreadsheet.<sup>7</sup> The content of this compliance filing will be heavily impacted by the outcome of this Reconsideration Application. On December 16, 2025, the BCUC issued Order G-309-25, in response to a request by PNG, and extended the date for the compliance filing to: (a) within two weeks following the BCUC's decision on the stay request, or (b) January 31, 2026, if PNG had not filed a stay request by that date. As is returned to below, PNG seeks a stay of the requirement to file its compliance filing until three weeks following the BCUC's decision on this Reconsideration Application.
12. With respect to process, PNG submits that there is sufficient evidence on the record in the underlying proceeding (and now supplemented by the new evidence of the BCER, as set out in this Reconsideration Application), to allow the BCUC to vary its decision on integrity management expenditures without further process. In the alternative, should the BCUC conclude that it requires further information, PNG submits that this application ought to proceed to a written hearing process. Likewise, PNG submits that the Reconsideration Application with respect to the rate smoothing mechanism ought to proceed to a written hearing process. We set out below a proposed regulatory process for the BCUC's consideration.
13. Finally, PNG seeks an increase to its interim rates to reflect the Decision, in order to avoid a buildup of under-recovered amounts while the Reconsideration Application is being considered.

### **PROCEDURE ON RECONSIDERATION**

14. PNG filed the Underlying Application with the BCUC on April 2, 2025, seeking approval from the BCUC of its revenue requirements for each year in the Test Period and the resultant proposed rate changes for this period.<sup>8</sup> The BCUC issued the Decision (Order and Decision G-270-25), on November 24, 2025. As is set out in more detail below, in this Reconsideration Application, PNG seeks reconsideration and variance of the Decision in two key respects: integrity management capital expenditures, and the 5-year rate smoothing deferral mechanism.
15. Section 99(1) of the UCA provides that: "[t]he commission, on application or on its own motion, may reconsider a decision, an order, a rule or a regulation of the commission and

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<sup>7</sup> Decision, Order #7.

<sup>8</sup> Ex. B-1, Underlying Application, p. 4.

may confirm, vary or rescind the decision, order, rule or regulation". Rule 30.02 of the BCUC Rules further provides that: "[t]he BCUC, on application or on its own motion, may reconsider a decision and may confirm, vary or rescind the decision".

16. An application for reconsideration must be filed within sixty days of the issuance of the relevant, underlying order and/or reasons for decision,<sup>9</sup> and must: (a) be in writing and, unless prior permission of the BCUC is obtained, not longer than 30 pages (excluding appendices and/or attachments); (b) identify the decision affected; (c) state the applicant's name and the representative's name, if applicable; (d) describe the impact of the decision and how it is material; (e) set out the grounds for reconsideration in accordance with Rule 31.05; and (f) set out the remedy the applicant is seeking.<sup>10</sup> PNG has addressed each of these requirements in this Reconsideration Application.
17. With respect to the requirement to set out the grounds for reconsideration, these are set out in Rule 31.05 of the BCUC Rules, which provides that the applicant must include one or more of the following: (a) the BCUC has made an error of fact, law, or jurisdiction which has a material bearing on the decision, (b) facts material to the decision that existed prior to the issuance of the decision were not placed in evidence in the original proceeding and could not have been discovered by reasonable diligence at the time of the original proceeding, (c) new fact(s) have arisen since the issuance of the decision which have material bearing on the decision, (d) a change in circumstances material to the decision has occurred since the issuance of the decision, or (e) where there is otherwise just cause.<sup>11</sup>
18. As is set out in more detail below, in this Reconsideration Application, PNG relies on the grounds for appeal set out in subsections (a), (b), (c), (d) and (e) of Rule 31.05, as the basis for the Decision to be reconsidered and varied.
19. Under Rule 33.01 of the Rules, upon the filing of an application for reconsideration, the Commission may, without further process, summarily dismiss the reconsideration application in whole or in part, on the basis that "it fails to establish, on its face, any reasonable grounds for reconsideration of the decision". Alternatively, in the event the Commission does not dismiss the whole application pursuant to Rule 33.01, the Application for reconsideration (or the portion that is not dismissed) will proceed to a hearing,<sup>12</sup> and the Commission will determine the regulatory process for the reconsideration hearing.<sup>13</sup>
20. PNG submits that this Reconsideration Application satisfies all of the requirements of the BCUC Rules and that the Commission ought to conclude that this Reconsideration Application establishes reasonable grounds, on its face, for reconsideration and order it to proceed to a hearing. In the section "Proposed Reconsideration Process" below, PNG sets out a proposed regulatory process, for the BCUC's consideration.

### **THE DECISIONS ON WHICH RECONSIDERATION IS SOUGHT**

21. PNG seeks reconsideration of the following two aspects of the Decision:
  - (a) the decision of the Panel to deny recovery in rates of 50 percent of the forecast integrity management capital expenditures of \$45.15 million over the Test Period; and

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<sup>9</sup> BCUC Rules, Rule 31.02.

<sup>10</sup> BCUC Rules, Rule 31.04.

<sup>11</sup> BCUC Rules, Rule 31.05.

<sup>12</sup> BCUC Rules, Rule 34.01.

<sup>13</sup> BCUC Rules, Rule 34.04.

- (b) the direction of the Panel that PNG set basic and delivery charges for the Test Period based on a 5-year rate smoothing scenario (as outlined in Panel IR 3.1) and establish a Rate Smoothing deferral account to set the Test Period rates based on this 5-year rate smoothing scenario.
22. Each of these aspects of the Decision are discussed below, in turn, including the grounds for reconsideration, the material impact of this aspect of the Decision, and the remedy sought by PNG.

### **DECISION 1: INTEGRITY MANAGEMENT CAPITAL EXPENDITURES**

23. In the Underlying Application, PNG sought approval of the following Integrity Management Capital Expenditures for the Test Period, which included forecast amounts for an Integrity Digs Campaign as well as an Integrity Assessment program:<sup>14</sup>

**Table 9: PNG's Forecast Integrity Management Capital Expenditures for the Test Period (\$'000s)<sup>105</sup>**

Capital Program	Forecast Capital Expenditures			
	2025	2026	2027	Total Test Period
Forecast Integrity Digs Campaign	\$6,826	\$11,557	\$9,139	\$27,522
Forecast Integrity Assessments	\$6,960	\$4,840	\$5,830	\$17,630
<b>Forecast Total Integrity Management</b>	<b>\$13,786</b>	<b>\$16,397</b>	<b>\$14,969</b>	<b>\$45,152</b>

24. The Integrity Assessments program utilizes in-line inspection (**ILI**) tools and technologies to assess the condition of sections of the transmission pipelines and detect defects in the integrity of a pipeline segment (such as corrosion metal loss, cracks, dents, laminations and bending strain).<sup>15</sup> PNG then undertakes an evaluation of the findings and determines defects that required direct assessment through the Integrity Dig Program. During the Test Period, seven ILI runs are planned for 2025-2026, with the scope of the 2027 program to be determined based on the incoming inspection and assessment results.<sup>16</sup> These assessment activities provide detailed information with respect to the condition of the pipeline and the growth of identified features to be addressed, and allow PNG to focus its Integrity Dig Campaign on defects identified as needing direct assessment.
25. The second aspect of PNG's Integrity Management activities is the Integrity Digs Campaign, through which specific physical excavations (direct assessment, or digs) are carried out on PNG's pipeline to assess defects identified through the integrity assessments and, if appropriate, mitigate them in order to maintain integrity of the transmission system. During the Test Period, PNG forecast conducting 294 integrity digs (at a cost of \$27.522 million).<sup>17</sup>
26. The Integrity Assessments program and Integrity Digs Campaign are carried out in conjunction with one another and include overlapping segments.<sup>18</sup> If, for example, the assessment activities are not undertaken to provide specific results, PNG would be compelled to apply more conservative assumptions to determining when to address defects, increasing the required dig activity (and cost), as well as creating potential risk to public

<sup>14</sup> Decision, pp. 18-19; Ex. B-1, Application, pp. 139, 152 and 164.

<sup>15</sup> Decision, p. 21; Ex. B-1, Application, p. 143.

<sup>16</sup> Ex. B-1, Application, p. 143; Ex. B-8, PNG Response to BCUC IR No. 1, IR 14.9.

<sup>17</sup> Decision, p. 19; Ex. B-1, Application, p. 145.

<sup>18</sup> Ex. B-1, Application, p. 144; Decision, p. 20

- safety if severe defects are not known. The two programs use an iterative process, with the programs being forecast/planned in advance but then adjusted to respond to new information as it is learned. This ensures that all pipeline operation, safety, regulatory and code requirements are being satisfied, allows PNG to maintain a safe, reliable gas supply and enables PNG's pipelines to remain complaint with regulatory requirements.<sup>19</sup>
27. Together, the programs have proven critical to PNG's integrity management plan, identifying relevant defects across PNG's system and allowing for their assessment and repair.<sup>20</sup> Further, both components are required elements of PNG's Integrity Management Program, which is overseen by the BCER.
  28. Importantly, the Integrity Digs Campaign and Integrity Assessment program support compliance with code and regulatory requirements, as well as the existing orders of the BCER.<sup>21</sup> For example, the digs undertaken are driven by the identification of features through the Integrity Assessment program that are determined to require direct assessment in accordance with CSA Z662:23. The evidence of PNG in this proceeding is that all of the planned digs are associated with either actionable ILI features or initiated based on known integrity threats (and that no planned digs fall outside the scope of validation or CSA-defined defect remediation).<sup>22</sup>
  29. Further, PNG's proposed spending is focused on maintaining the current operating pressure for the R1 to Kitimat segment of PNG's transmission pipeline (800 psig),<sup>23</sup> and maintaining the current operating pressure on the Terrace to Prince Rupert mainline (at 424 psig).<sup>24</sup>
  30. The licensed maximum operating pressure of the R1 to Kitimat segments is 1,414 psig. In 2021, the BCER ordered PNG to reduce its operating pressure on its transmission pipeline until such time as necessary integrity work was completed to support increased operating pressures.<sup>25</sup> In past years, PNG completed the necessary integrity work to reinstate the R1 to R4 segment to its current operating pressure, and undertook integrity work towards reinstating the operating pressure for the R4 to Kitimat segment to 800 psig (which has now occurred). PNG developed the currently proposed program to maintain its operating pressure of 800 psig, as opposed to undertaking the work necessary to further increase its operating pressure in advancement of compliance with the BCER's General Order. The basis of this approach was to optimally manage cost considerations and rate impacts while keeping operating pressures at a level where PNG can serve customers safely, reliability and with some resiliency room.<sup>26</sup> Ultimately, the BCER is actively monitoring PNG's integrity management as part of its General Order 2021-0115-05, and the successful execution of these programs is a critical step in the eventual termination of this order.<sup>27</sup> The BCER expects PNG to continue to slowly build its operating pressure towards the licensed maximum operating pressure, in order to allow for the eventual termination of the General Order (and, for clarity, we confirm that this has not been included in the proposed campaign).
  31. With respect to the R1 to R4 segment, PNG has been able to operate this segment at 800 psig since 2024, per the BCER; however, even where 800 psig has been achieved, ILI inspection and integrity dig excavations/repairs must be continuously performed in order to

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<sup>19</sup> Decision, pp. 19, 23; Ex. B-1, Application, p. 145; Ex. B-8, PNG Response to BCUC IR No. 1, IR 14.5.

<sup>20</sup> Ex. B-1, Application, p. 143.

<sup>21</sup> Decision, p. 20.

<sup>22</sup> Ex. B-9, PNG Response to BCOAPO-RCIA IR No. 1, IR 12.4.

<sup>23</sup> As is returned to below, the R4 to Kitimat segment has recently been 589 psig to 800 psig.

<sup>24</sup> Ex. B-1, Application, p. 144; Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.7; Decision, p. 20.

<sup>25</sup> See BCER General Order 2021-0115-01.

<sup>26</sup> Ex. B-9, PNG Response to BCOAPO-RCIA IR No. 1, IR 12.3.

<sup>27</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.5.

maintain the continued operations at this level.<sup>28</sup> With respect to the R4 to Kitimat segment, at the time of the Application and proceeding, PNG was operating this segment at 589 psig;<sup>29</sup> however, the majority of the work (99.4%) necessary to increase the operating pressure to 800 psig had been previously completed.<sup>30</sup> As of December 2025, PNG has completed this further work, and the BCER has recently amended its General Order to allow PNG to raise the operating pressure to 800 psig due to the successful Integrity Assessments, digs and repairs completed in 2025 and prior years. However, even with 800 psig achieved, ILI inspection and integrity dig excavations/repairs must be continuously performed to maintain the continued operations at this level, as with the R1 to R4 segment. Likewise, on the Terrace to Prince Rupert Mainline (which is currently operated at 424 psig), the program currently proposed focuses on maintaining operating pressure at this level, which requires ongoing integrity work.<sup>31</sup>

32. Interveners BCOAPO and RCIA supported PNG's forecast expenditures related to the integrity management capital expenditures over the Test Period, on the basis that they are necessary to establish a reasonable safe operating pressure, and to address BCER orders and requirements.<sup>32</sup>
33. In the Decision, the Panel found that PNG had not demonstrated the need for integrity-management spending at the levels forecast for the Test Period. As a result, it denied recovery in rates of 50 percent of the forecast expenditures of \$45.15 million and directed PNG to reflect this in the schedules of its directed compliance filing.<sup>33</sup>

#### **A. The Grounds for Reconsideration**

34. PNG submits that the BCUC made an error in fact or law, which had a material bearing on the Decision, in denying recovery in rates of 50 percent of the forecast expenditures. Further and in any event, since the Decision (and in response to the Decision), new facts have arisen which have a material bearing on the Decision.

#### **The Panel Erred in Finding that PNG Failed to Demonstrate Need**

35. As noted above, in denying recovery in rates of 50 percent of the forecast expenditures for integrity management, the Panel found that PNG had not demonstrated the need for integrity-management spending at the levels forecast for the Test Period.<sup>34</sup> In doing so, the Panel cited the BCUC's decision with respect to PNG's 2020-2021 RRA where the Commission urged PNG to include detailed discussions for the need for integrity management activities and highlight project prioritization and alignment with overall system planning, as well as identify costs which PNG considers necessary to comply with mandated regulatory requirements of the BCER.<sup>35</sup> The Panel noted in the Decision that it "expects PNG to make greater efforts to contain capital spending, in particular during this period of

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<sup>28</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IRs 15.7, 15.7.1 and 15.8; Ex B-11, PNG Response to Panel IR No. 1, 1.7.

<sup>29</sup> Ex B-11, PNG Response to Panel IR No. 1, IR 1.7.

<sup>30</sup> Ex B-11, PNG Response to Panel IR No. 1, IRs 1.2 and 1.3.

<sup>31</sup> Ex. B-8, PNG Response to BCUC IR #1, IR 15.9.

<sup>32</sup> Decision, p. 22.

<sup>33</sup> Decision, pp. 22, 23.

<sup>34</sup> Decision, p. 22.

<sup>35</sup> Decision, pp. 22-23, citing to Decision and Order G-255-20 on PNG 2020-2021 RRA for the West Division, dated October 14, 2020.

substantial rate increases that are due in part to significant integrity-management related spending”.<sup>36</sup>

36. PNG submits it was an error for the BCUC to conclude that PNG had not demonstrated need for its integrity management spending, and to suggest that PNG has not made efforts to contain this type of spending.
37. In putting forward its revenue requirements in the Underlying Application, PNG heeded the advice of the BCUC around prioritizing only necessary integrity spending to contain total capital spending, particularly in light of the substantial rate increases sought in the Underlying Application. The amounts put forward for integrity management capital expenditures captured only the activities necessary to meet the threshold for acceptable system sustainment by industry and engineering standards. As noted above, the program was developed to balance PNG’s need to maintain an operating pressure of 800 psig to enable safe and reliable service to its customers, while at the same time undertaking the work necessary to advance compliance with BCER General Order 2021-0115-03,<sup>37</sup> which anticipates work will be completed towards eventually restoring the pipeline to its MOP, to allow for the termination of the General Order. The balance reached by PNG in this regard was strongly driven by the cost pressures faced by PNG. As a result, none of the spending proposed by PNG can be deferred during the Test Period, without severely diminishing PNG’s ability to manage pipeline integrity as a reasonable operator, meet the expectations of the BCER, and adhere to the CSA Z662:23 standard.
38. Further and in any event, even if certain work could be deferred beyond the Test Period to reduce current spending (which would be problematic for the reasons set out above), this would merely delay and compound the work to future periods. Much like home maintenance, deferring work simply delays it, rather than avoids it, and it is often much more challenging and expensive to try and “catch up” again in the future (particularly if it is necessary to undertake additional work in order to get operating pressures back up to present levels).
39. Specifically, we note that the evidence put forward by PNG in the underlying proceeding included the following with respect to the necessity of the work forecast and lack of discretion:
  - (a) PNG confirmed in the Underlying Application that the forecast capital expenditures were “considered necessary for the ongoing safe and reliable service provided by [PNG] and are predominantly justified and driven on a priority basis from pipeline and facility related safety and loss management related programs ... as well as the prudent measures necessary for the ongoing management of aging pressure containing assets”,<sup>38</sup>
  - (b) In its response to IRs, PNG explained the hazard identification and risk assessment process used to determine whether a run/inspection is required to prioritize those ILI runs that need to be completed (including using risk assessment to prioritize work activities, to ensure that the planned/proposed expenditures result in the greatest risk reduction, balancing costs and rate pressures);<sup>39</sup>

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<sup>36</sup> Decision, p. 23.

<sup>37</sup> Ex. B-8, PNG Response to BCUC IR #1, IR 15.5.

<sup>38</sup> Underlying Application, p. 143 (emphasis added).

<sup>39</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 14.11.

- (c) PNG confirmed that all planned integrity digs were associated with either actionable ILI features (subject to validation and/or remediation), or indicated based on known integrity threats assessed through engineering analysis;<sup>40</sup>
- (d) When asked by the BCUC about its ability to adjust the scope or timing of the dig campaign, PNG confirmed that it had only “limited discretion”, given the complex technical-integrity, scheduling, resource planning and compliance related factors which make even moderate changes to the plan difficult. While the program may have some flexibility to allow deferral, cancellation or addition, this would be based on risk-analysis conducted through the course of the ongoing integrity work and be for only “a relatively minor number of digs”.<sup>41</sup> Relatedly, PNG expressly confirmed that it is unable to defer or reduce the scope of its Integrity Dig Campaign, and had prioritized activities needed to ensure ongoing technical and regulatory compliance and to advance work needed for the BCER:

PNG is unable to defer or reduce the scope of its 2025-2027 Integrity Dig Campaign in this Test Period. In making this decision, PNG prioritized its need to meet ongoing technical and regulatory compliance requirements to allow it to safely and reliably operate its system. As noted in PNG’s response to BCUC IR 15.7, the integrity dig campaign for period 2025-2027 is designed around maintaining operating pressures of 800 psi for the R1-Kitimat pipeline segment, and 424 psi for the Terrace to Prince Rupert pipeline segment. These pressures are the minimum operating pressure at which PNG can operate its system while maintaining a safe and reliable supply of natural gas. Further, operating at these pressures provides the minimum required operational resiliency to ensure uninterrupted supply in the face of an emergency or planned maintenance activities.

PNG continues to be subject to BCER General Order 2021-0115-05 which restricts PNG’s operating pressures until such time as PNG has done the necessary integrity work to have the order terminated. PNG is expected to continue to advance its works to remove these BCER restrictions. Further, the scope of the Integrity Dig Campaign supports PNG’s ongoing compliance with technical codes and requirements.<sup>42</sup>

See also PNG’s Response to Panel IR No. 1, where PNG confirmed that its integrity digs were “non-discretionary and required to ensure continued safe operations”;<sup>43</sup>

- (e) With respect to Integrity Assessments specifically, these assessments are carried out in conjunction with the Integrity Dig Campaign and provide data and information to help guide the Integrity Dig Campaign. Deferring ILIs and engineering assessment work would mean that PNG has less specific information to guide its Integrity Dig Campaign – meaning that it would need to carry out its digs using more conservative assumptions (which, in turn, could exponentially increase the number of digs required and relatedly increase the costs). As indicated in IR responses, changes to

<sup>40</sup> Ex. B-9, PNG Response to BCOAPO-RCIA IR No. 1, IR 12.4.

<sup>41</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.6.

<sup>42</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.7.1.

<sup>43</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 1.5.

the planned Integrity Assessments would be a fundamental change to the overall program and may ultimately impact pipeline integrity.<sup>44</sup>

- (f) With respect to the Terrace to Prince Rupert Mainline, the BCUC asked PNG in IRs to confirm whether any digs were not strictly required, PNG confirmed that it had included no integrity digs for the Test Period that were “above and beyond what is strictly required to maintain this pipeline segment at 424 psig”.<sup>45</sup>
  - (g) Ultimately, PNG confirmed that the forecast expenditures included with its Underlying Application represented the best estimates available of the integrity work necessary, and would be revised, as needed, in response to new information obtained through other ILI and ongoing integrity analysis.<sup>46</sup>
40. As was summarized in PNG’s final argument, in putting together the revenue requirements sought, PNG made a significant effort to keep operating costs down, optimize its identified capital spending, prioritize its capital spending relative to risk, maintain its operating system at the pressure required to meet current load requirements, minimize capital spending required, and delay non-critical work on the system, while also still providing safe and reliable service to customers.<sup>47</sup> PNG recognized the impact of the planned activities on cost of service and customer rates, but confirmed that the planned work could not be deferred, and is critical to ensuring that customers can be served in a safe and reliable manner, while ensuring compliance with codes, standards and industry expectations.<sup>48</sup> PNG’s decision to develop a program that continues operation at 800 psig (or approximately 50 percent of the maximum operating pressure of 1,414 psig), itself illustrates that PNG is putting significant weight on cost control, and only doing the work strictly necessary to safely and reliably meet its demand.
41. PNG respectfully submits that it provided sufficient evidence in the proceeding to demonstrate a need for all of the forecast spending, and that there was not a further ability for work to be prioritized or postponed, and that it was an error for the BCUC to conclude otherwise.

### **The Panel Erred in Suggesting that PNG’s Past Expenditures Should Reduce Future Expenditures**

42. Further, the BCUC notes in its Decision that the planned integrity digs for the Test Period (294 digs, at a cost of \$27.5 million), is a significant increase over the digs forecast for the Test Period as part of PNG’s 2023-2024 RRA.<sup>49</sup> This adjustment to the forecast was made because, as is typically done, PNG’s understanding of its pipeline integrity condition evolved as it performs inspections, engineering assessments, and integrity digs, adjusting to new information gained to ensure that pipeline operational, safety, regulatory and code requirements are satisfied.<sup>50</sup> Further, the BCUC highlighted that PNG had already completed a “substantial amount of pipeline integrity work over the last four years”, taking this factor into account in concluding that a 50 percent reduction in the forecast capital expenditures would be appropriate and enable PNG to conduct priority work in order to

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<sup>44</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 14.8.

<sup>45</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 1.4.

<sup>46</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.3.

<sup>47</sup> PNG Final Argument, para. 11.

<sup>48</sup> PNG Final Argument, para. 95.

<sup>49</sup> Decision, p. 23.

<sup>50</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.3.

maintain safe and reliable service.<sup>51</sup> This seems to suggest that, because PNG spent a sizeable amount on integrity work in the past, it may spend less moving forward. PNG respectfully submits that this is not correct and the BCUC was in error in reaching this conclusion.

43. With respect to the substantial integrity work completed over the last four years, as set out above, in 2021 the BCER ordered PNG to reduce its operating pressure on its transmission pipeline until such time as necessary integrity work was completed to support increased operating pressures.<sup>52</sup> PNG undertook a substantial amount of integrity work, which required increased spending, in order to increase the operating pressure for the R1 to R4 segment to 800 psig (and towards increasing the operating pressure for the R4 to Kitimat segment which, as returned to below, has now also been increased to 800 psig). However, despite the past work undertaken to support increased operating pressures, there remains an ongoing obligation for PNG to carry out ongoing integrity work to maintain these pressures.
44. This work is guided by the inspections/assessments completed, and historic spending does not directly or necessarily reduce future and ongoing spending. The integrity work carried out by PNG since 2021 has impacted the program currently proposed, in the sense that PNG has learned more about the integrity condition of its assets, gained efficiencies in dig execution, and used the data collected as part of the inspections and assessments over that time period to refine the integrity forecasts for this Test Period,<sup>53</sup> however, it has not eliminated the need for further and ongoing work, particularly given PNG's aging infrastructure.
45. For example, when previously carrying out ILI on certain segments, PNG identified deeper cracks than expected, which may indicate more aggressive growth rates than previously anticipated and warranting the increased ILI frequency on these segments during the Test Period. As PNG has noted elsewhere, it adjusts planned work as integrity conditions warrant.<sup>54</sup>
46. As was submitted by PNG in its final argument, it remains critical that PNG continue to address aging infrastructure and ensure its compliance with pipeline integrity codes, standards and regulations, which has resulted in the need for more resources.<sup>55</sup> This continues regardless of past amounts spent (and, even if amounts could be deferred now, which is problematic in and of itself, the deferred work would snowball and compound in future periods).
47. In any event, PNG is moving closer to a place of sustainment when considering annual dig counts because it has been able to increase its operating pressure to a level that allows it to safely and reliably service its customers and, as such, it is now maintaining this pressure as opposed to needing to complete the work on an expedited basis to increase pressure. While PNG needs to continue to undertake the necessary integrity work to address its compliance requirements under the BCER General Order, the timelines upon which it must do this are not as expedited as those faced in the 2021-2023 period. Specifically, 2021 to 2023 were the peak of annual dig efforts (with 316 digs carried out in in 2023 alone), and the number of digs has been decreasing since that time (with 294 digs forecast for the three-

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<sup>51</sup> Decision, p. 23.

<sup>52</sup> See BCER General Order 2021-0115-01.

<sup>53</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.11.

<sup>54</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 14.5.

<sup>55</sup> PNG Final Argument, para. 11.

year Test Period).<sup>56</sup> From a cost perspective it is noteworthy that in the 2023, PNG spent \$50.7 million on integrity related activities, and a total of \$60.0 million over the 2023-2024 (two year) test period<sup>57</sup> while in the Underlying Application, PNG had reduced its integrity spending significantly, to approximately \$15 million per year (\$45.1 million for the three-year Test Period).

48. There is no evidence on the record in the underlying proceeding to suggest that the significant integrity work performed by PNG prior to 2025 should or could reduce the work necessary to be completed during the Test Period to maintain current operating pressures and to address the BCER General Order, and it was an error for the Panel to reach this conclusion.

### **Operating Pressure and the BCER**

49. In the Decision, the Panel also noted that PNG had not been directed or ordered to complete any of the planned activities by the BCER,<sup>58</sup> and that the BCER has confirmed that the pipeline is safe to operate at the current pressures.<sup>59</sup> While it is correct that PNG has not been mandated by the BCER to carry out specific activities, this finding does not factor in that PNG has an obligation to undertake prudent integrity work to comply with code requirements regulated by the BCER and to address the integrity activities to achieve compliance with General Order 2021-0115-05 (such that it can eventually be terminated). As PNG submitted in evidence in the proceeding (in response to BCUC IR No. 1):

The BCER has not directed or ordered any direct assessment or study scope related to the 2025-2027 Transmission Mainline Integrity Dig Campaign; **however, as a prudent operator, PNG must carry out pipeline integrity work to ensure it can meet or exceed code requirements regulated by the BCER. The BCER actively monitors PNG's Dig Campaign as part of General Order 2021-0115-05,<sup>3[60]</sup> the successful execution of this annual program is a critical step in eventual termination of this order.**

In the absence of performing the required digs to maintain the existing operating pressure, PNG may need to self-lower the maximum operating pressure further. The BCER may also impose additional pressure reductions with a more restrictive order. In that case, PNG would be unable to meet its existing load requirements.<sup>61</sup>

50. It is not the role of the BCER to direct PNG to perform specific integrity work. Pursuant to the *Pipeline Regulation*, which was enacted under the *Energy Resource Activities Act*, PNG is required to have a pipeline integrity management program that complies with certain minimum codes, as a condition to operate.<sup>62</sup> This program is overseen by the BCER, which ensures that the program is satisfactory, and that PNG is executing its integrity work pursuant to the program. The program is a condition of PNG's Licence to Operate under the *Pipeline Regulation* and, as such, failing to implement the program puts PNG's licence at risk. Further, the BCER monitors PNG's integrity work completed in compliance with General Order 2021-0115-05 and, as noted previously, with a goal towards eventually

<sup>56</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 1.8; Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.11.

<sup>57</sup> Ex. B-1, Application, p. 206 and p. 210.

<sup>58</sup> Decision, p. 20.

<sup>59</sup> Decision, p. 23.

<sup>60</sup> See: [www.bc-er.ca/files/enforcement/Enforcement-Order/General-Order-2021-0115-05.pdf](http://www.bc-er.ca/files/enforcement/Enforcement-Order/General-Order-2021-0115-05.pdf)

<sup>61</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.5 (emphasis added).

<sup>62</sup> *Pipeline Regulation*, BC Reg 210/2010, s. 7.

further increasing operating pressures towards the pipeline MOP (so the General Order can be rescinded). The BCER requires PNG to provide an annual engineering assessment of the dig activities completed, and to provide a stamped Declaration of Safe Operation to demonstrate compliance and the ability to safely operate at the current pressures.<sup>63</sup> PNG's integrity campaign was developed by its engineers, so that the Company would be able to provide the BCER with this critical information. As was set out in PNG's response to Panel IRs, if PNG does not complete the required integrity activities to support the current pressure level, this will need to be disclosed to the BCER, and the BCER may lower the allowed operating pressure based on the outcome of integrity assessments and/or impose further requirement on PNG to address perceived gaps in integrity related activities.<sup>64</sup> Relatedly, PNG would need to voluntarily reduce its operating pressure if it determines that it is unable to safely operate at current operating pressures.

51. Since the issuance of the Decision, the BCER has notified PNG that it is aware that PNG's funding for future integrity activities has been limited as a result of the Decision, such that certain inspection and repair activities planned for the Test Period will not be completed. PNG understands the BCER to be very concerned by this, and it has also confirmed that it may implement further reductions in pipeline operating pressures as a result of the deferred inspection and repair activities.
52. Please see attached at **Schedule "A"**, a copy of an email received by PNG from the BCER on January 8, 2026. This email was not available to PNG at the time of the Underlying Application and the Decision, and is relevant to PNG's position that the full amount of the forecast integrity spending ought to be approved.
53. PNG notes that the BCER has also indicated that it requires PNG to complete engineering assessments of the impacted pipeline segments to assess the impact of deferred activities on the integrity of the pipeline system.<sup>65</sup> If PNG must reduce its overall spending on its integrity management program by 50 percent, it is very concerned that it will be unable to provide the BCER with engineering efforts to support an ongoing operating pressure of 800 psig, and would need to voluntarily reduce its pipeline operating pressure.
54. As is discussed in more detail below under the heading "The Material Impact of the Decision", the consequences of any operating pressure reduction would be very serious for PNG and its customers.
55. It was an error for the BCUC to conclude that, because the BCER has confirmed that PNG may currently safely operate at the current operating pressures, that this may be maintained moving forward without carrying out the forecast integrity expenditures. Further and in any event, new evidence is available from the BCER, in specific response to the Decision, that is relevant to the Panel's findings on integrity management capital expenditures, that supports reconsideration.

### **The 50 Percent Reduction is Arbitrary**

56. Finally, PNG respectfully submits that it was an error for the BCUC to arbitrarily reduce the amount of its integrity spending by 50 percent, as well as a breach of its duty of procedural

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<sup>63</sup> Ex. B-11, PNG Response to Panel IR No. 1, 1.9.

<sup>64</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 1.9.

<sup>65</sup> PNG is working with the BCER to understand what it requires. It understands that, when PNG makes annual submissions to the BCER around the safe operating pressure, the BCER requires it to include engineering assessments that demonstrate the decisions that were made regarding safe operations, given the reduced budget, and that this engineering work demonstrates that the appropriate work has been done to support this operating pressure.

fairness as PNG was not given an opportunity to comment on the impact of this level of reduction.

57. As noted above under the heading “The Panel Erred in Finding that PNG Failed to Demonstrate Need”, the evidence put forward by PNG was that it was unable to defer or reduce the scope of the Integrity Dig Campaign proposed during the Test Period (which sentiment notably applies to PNG’s entire integrity program and not just the Integrity Dig Campaign). This evidence was provided in response to an IR posed by the BCUC, which specifically asked PNG to weigh near-term rate impacts above other facts, such as preserving long term system capabilities.<sup>66</sup> PNG does not have the ability to defer or prioritize expenditures within a budget that has been reduced by 50 percent, while also maintaining safe and reliable service during the Test Period, nor is there any evidence in the proceeding to suggest otherwise. Importantly, PNG was not asked to comment on the impact of a 50 percent reduction before it was ordered.
58. Further, PNG notes that the denial in recovery of rates in the Decision (of 50 percent of the forecast integrity management capital expenditures over the entire Test Period of 2025-2027), is different from the denial that was made by the BCUC in Order G-284-25 on December 4, 2025, with respect to Pacific Northern Gas (N.E.) Ltd. (**PNG(NE)**) (where that entity was denied recovery in rates of 50 percent of the forecast integrity management capital expenditures over only 2026 and 2027, but allowed to recover the full amount for 2025). There is no indication given in either the Decision or Order G-284-25 for this distinction.
59. As the planned program had already been designed around ensuring PNG undertakes only the work necessary to maintain its current operating pressure so as to mitigate the potential rate impacts of the required integrity work during the Test Period, it was an error for the BCUC to conclude that it could disallow 50 percent of PNG’s integrity spending, while leaving it with the “discretion” to prioritize the work needed to safely continue operations (as PNG has no means to carry out such a prioritization of non-discretionary work).
60. The BCUC’s decision to disallow 50 percent of PNG’s integrity spending (seemingly arbitrarily) intrudes into an area that the Court of Appeal has expressly characterized as core management responsibility in *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106. There, the Court of Appeal emphasized that, absent the extraordinary assumption of management under the UCA, the formulation and execution of plans for a utility’s future remain the responsibility of its directors, not the Commission.<sup>67</sup> Planning decisions, including how resources are allocated to meet statutory obligations over time, are inherent to management and do not form part of the Commission’s supervisory jurisdiction over rates or the certification of specific projects. At paragraph 58 the Court of Appeal noted:

Taken as a whole the *Utilities Act* [now UCA], viewed in the purposive sense required, does not reflect any intention on the part of the legislature to confer upon the Commission a jurisdiction so to determine, punishable on default by sanctions, the manner in which the directors of a public utility manage its affairs.

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<sup>66</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 15.7.1.

<sup>67</sup> *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106, paras. 55-56.

61. PNG respectfully submits that the BCUC denying recovery of 50 percent of the integrity expenditures that PNG has deemed essential oversteps into trying to manage the manner in which PNG manages its affairs.
62. As is returned to below under the heading “The Material Impact of the Decision”, the impact of such a 50 percent reduction on PNG and its customers will be severe.
63. It was an error for the BCUC to deny recovery of 50 percent of PNG’s proposed expenditures, and PNG ought to be given a fulsome opportunity to comment on the impact of such a decision through a reconsideration process.

### **PNG May Recover Reasonably Incurred Expenses**

64. Ultimately, an application under the rate setting provisions of the UCA (ss. 58-61) requires the BCUC to assess whether the rates proposed to be collected by a public utility are just and equitable based on all of the evidence in the record before it. Under s. 59(5)(b) of the UCA a rate is “unjust” or “unreasonable” if it is “insufficient to yield fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property”.<sup>68</sup>
65. As is discussed in more detail in the next section, “The Material Impact of the Decision”, as a result of the Decision, PNG is faced with the untenable outcome of not performing integrity work which it has assessed as necessary and unable to be deferred (severely diminishing PNG’s ability to manage pipeline integrity as a reasonable operator, and risking its current operating pressure being decreased). If PNG is denied recovery of 50 percent of these expenditures, as ordered by the Decision, its rates will be unjust and/or unreasonable, and insufficient to yield a fair and reasonable compensation for the service provided by the utility or a fair and reasonable return on the appraised value of its property.

### **B. The Material Impact of the Decision**

66. The Panel’s decision to deny recovery of 50 percent of PNG’s integrity management capital expenditures will have a material, negative impact on PNG, its ratepayers and its infrastructure.
67. As set out above, the Underlying Application included only the integrity expenditures that are strictly necessary to safely and reliably meet its loads. This leaves no room for PNG to try and “prioritize” these activities, without severely diminishing PNG’s ability to manage pipeline integrity as a reasonable operator.
68. At the time of the Decision, PNG had already spent \$13.710 million on integrity management activities for 2025. If total expenditures for the Test Period are reduced to \$22.576 million (or 50 percent of \$45.152 million), this leaves only approximately \$9 million for capital expenditures for 2026 and 2027 (or, \$4.5 million per year). This represents only approximately 25% of the planned expenditures for 2026 (\$16.397 million) and approximately 27% of the planned expenditures for 2027 (\$14.969 million).<sup>69</sup>
69. At this reduced spending level, PNG has a serious concern about its ongoing ability to operate. More specifically:

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<sup>68</sup> See *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1993), 66 BCLR (2d) 1 at para. 55.

<sup>69</sup> See Decision, p. 19.

- (a) PNG will not be able to carry out the integrity activities necessary to maintain the current level of operating pressure;
  - (b) as a result, PNG's engineers will not be able to submit an annual Declaration of Safe Operations to the BCER, that confirms that the pipeline is able to be safely operated at current operating pressures;
  - (c) PNG will be at risk that either PNG, voluntarily or the BCER, through order, may implement further reductions in pipeline operating pressures;
  - (d) as operating pressure drops, there will come a point where operations will need to be interrupted, and PNG's ability to serve its existing customers will be impacted. This creates a public safety risk for PNG's customers, as well as its larger customers who rely on gas to operate businesses (such as large smelters, forestry, propane and other large economic drivers in Northern British Columbia);
  - (e) further, PNG's ability to take on new customers will also be impacted (including the prospective new customers in the North);
  - (f) PNG's overall asset risk will increase and past investments will be stranded; and
  - (g) PNG's reputation with the BCER will decline (and PNG has been working closely with the BCER in order to maintain current operating pressures, with the goal of eventually having the limits removed) such that PNG may be exposed to additional orders that would not otherwise have been made.
70. Should the BCUC order that this Reconsideration Application proceed to a hearing, PNG will seek leave to introduce evidence on the significant impact of a 50 percent reduction in expenditures on integrity work. In doing so, it respectfully notes that it was not previously given an opportunity to comment on the impact of a 50 percent reduction, such that this evidence was not put forward as part of the underlying proceeding.
71. Given the serious consequences of not performing the integrity work, disallowing PNG's ability to recover for this spending places PNG in the untenable position of having to decide how to meet its legal requirements to provide safe and reliable service to its customers, if even possible within approved spending limits, or to seek relief from having to serve certain customers. It is a legal error to leave PNG unable to recover its reasonable and prudently incurred (and necessary) expenses in its rates.
72. As can be seen from the email attached as **Schedule "A"**, the BCER is also concerned by the reduced funding for integrity work, and has indicated that it may implement further reductions in pipeline operating pressure as a result of deferred inspection and repair activities. PNG is very concerned that it will not be able to deliver its integrity program, within the current capital expenditure amount, in a manner that will satisfy the requirements of the BCER such that current operating pressures can be maintained. Relatedly, PNG is very concerned that moving forward at this reduced spending level, its engineers will not be able to continue to support its current operating pressure and therefore would expect to have to voluntarily reduce operating pressures in the near term (or face an ordered reduction by the BCER).

### C. The Remedy Sought

73. PNG seeks to vary Order G-270-25 and the accompanying Decision, such that PNG be permitted to recover in rates the full \$45.15 million in forecast integrity management capital expenditures for the Test Period and be directed to reflect this full amount for the Test Period in its compliance filing.
74. As is returned to below, under the heading “Proposed Reconsideration Process”, PNG submits that there is sufficient evidence available (on the record in the underlying proceeding, as updated by the new evidence from the BCER (Schedule “A”)) for the BCUC to vary the Decision with respect to integrity management expenditures, without the need for further process. A prompt resolution of this issue will allow PNG to plan for its upcoming integrity management work (which is largely carried out over the spring and summer months). Alternatively, if the BCUC concludes that it requires additional information to determine whether this order ought to be varied, a proposed reconsideration process is set out.

#### **DECISION 2: RATE SMOOTHING MECHANISM**

75. In the Underlying Application, PNG proposed a rate smoothing deferral mechanism which would see \$12.036 million of the 2025 revenue deficiency recorded in a rate smoothing deferral account and amortized over 2026 and 2027, to distribute the rate impact over the Test Period.<sup>70</sup> This proposed mechanism is summarized as follows:<sup>71</sup>

**Table 12: Summary of Test Period Revenue Deficiencies and Rate Changes  
With and Without Rate Smoothing Mechanism**

	Test Year 2025	Test Year 2026	Test Year 2027
<b>Without Rate Smoothing Deferral Mechanism<sup>197</sup></b>			
Revenue deficiencies (\$'000s)	26,668	1,113	3,665
Residential rate increases year-over-year	50.6%	1.1%	4.6%
<b>With Rate Smoothing Deferral Mechanism</b>			
Revenue deficiencies (\$'000s)	14,632	19,134	4,539
Residential rate increases year-over-year	27.8%	27.8%	5.0%

76. In developing and putting forward this approach, PNG explored a variety of scenarios for recovery of its deferral account balances, taking into consideration a variety of competing factors, including overall carrying costs, rate impacts in the Test Period and beyond, and the need to position PNG to have more stable and predictable rate increases in the future. While PNG has previously used two-year test periods, it proposed a three-year rate smoothing over the Test Period in the Underlying Application, in order to spread the rate impact of the revenue requirements over a longer period. In doing so, it accepted additional risk (as it was required to forecast out further than it typically would).<sup>72</sup>
77. The approach proposed by PNG in the Underlying Application mitigated the significant 2025 rate increase that would occur without rate smoothing, while limiting carrying costs on deferred revenue, keeping down the cumulative rate impact (71.4 percent) and resulting in

<sup>70</sup> Ex. B-1, p. 140; Decision, p. 32

<sup>71</sup> Decision, p. 33.

<sup>72</sup> Ex. B-8, PNG Response to BCUC IR No. 1, IR 26.1.

no deferral amounts (or associated interest) being carried into future periods. In putting forward its Underlying Application, PNG also confirmed that it did not have sufficient information to enable forecasting beyond the Test Period (i.e. beyond 2027).<sup>73</sup>

78. During the proceeding, the Panel asked PNG to explore alternative rate smoothing options, including rate smoothing evenly over 5 and 10 years.<sup>74</sup> In carrying out these exercises in response to IRs, PNG emphasized that it has not determined its cost of service or revenue requirements for 2028 and beyond,<sup>75</sup> that simplifying assumptions were necessary to analyze rate smoothing beyond the Test Period, and the fact that changes to even one of these assumptions could result in “materially different results”.<sup>76</sup> The rate smoothing options are summarized as follows:<sup>77</sup>

**Table 13: Summary of Rate Smoothing Options**

	3-year Rate Smoothing (2025–2027 under PNG’s Proposal)	3-year Rate Smoothing (2025– 2027 with Even Annual Impact)	5-year Rate Smoothing (2025–2029)	10-year Rate Smoothing (2025–2034)
Average annual rate increases over each period	Note A*	23.3%	17.2%	11.6%
Cumulative rate increase over each period	71.4%	87.4%	120.9%	199.2%

*\*Note A: Under PNG’s rate smoothing proposal, increases would be 27.8 percent in 2025, 27.8 percent in 2026, and 5.0 percent in 2027.*

79. PNG also raised concerns with any rate smoothing that would extend beyond the Test Period. Having considered the alternative scenarios, in final argument, PNG continued to submit that the rate smoothing proposed in its Underlying Application ought to be adopted.<sup>78</sup>
80. The interveners in the proceeding, BCOAPO and RCIA, recommended rate smoothing over six-years and three-years, respectively. In proposing 3-years, RCIA recognized that while extending rate smoothing beyond the Test Period would be beneficial to customers in the short-term, this benefit was outweighed by the risk of recovering the deferred amounts from a potentially decreasing customer base or becoming unable to recover the deferred amounts at all.<sup>79</sup>
81. In the Decision, the Panel noted that PNG raised several concerns with the 5- and 10-year rate smoothing scenarios, including that they incorporated simplifying assumptions (and that changes could lead to materially different results), the risk of deferring a portion of its revenue requirements into future periods raises concerns related to imposing costs on future customers, and increases financial risk by reducing cash flow, impacting recoverability of deferred amounts (including due to declining demand and forecast uncertainty) and potentially impacting PNG’s access to equity and debt and the cost of financing its operations.<sup>80</sup> However, while the Panel acknowledged PNG’s concerns (and noted that they were shared by RCIA), it found that this must be weighed against the

<sup>73</sup> Ex. B-1, Application, p. 40; Ex. B-8, PNG Response to BCUC IR No. 1, IR 26.1; Ex. B-11, PNG Response to Panel IR No. 1, Ex. IR 2.1.

<sup>74</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 2.1; Ex. B-12, PNG Response to Panel IR No. 2, IR 3.1.

<sup>75</sup> Ex. B-11, PNG Response to Panel IR No. 1, IR 2.1.

<sup>76</sup> Ex. B-12, PNG Response to Panel IR No. 2, IR 3.1.

<sup>77</sup> Decision, p. 33.

<sup>78</sup> PNG Supplemental Final Argument, paras. 12-15.

<sup>79</sup> Decision, pp. 34-35.

<sup>80</sup> Decision, pp. 34-35.

magnitude of the requested rate increases, and found that rate smoothing over a period of 5-years is the appropriate balance between mitigating customer rate impact and managing risks related to deferring revenue requirements.<sup>81</sup>

82. In the Decision, PNG was directed to: (a) set basic charges and delivery charges for 2025, 2026 and 2027 based on the 5-year rate smoothing scenario outlined in Panel IR 3.1 (Exhibit B-12); and (b) establish a rate smoothing deferral account to set the Test Period rates based on a 5-year rate smoothing scenario, attracting interest at PNG's weighted average cost of capital, effective January 1, 2025.<sup>82</sup> The Panel also directed PNG to "[a]ddress the disposition of the Rate smoothing deferral account balance at December 31, 2027 in the next RRA".<sup>83</sup>

#### **A. The Grounds for Reconsideration**

83. PNG submits that the BCUC made an error in fact, law or jurisdiction, which had a material bearing on the Decision, in ordering rate-smoothing over five years and the ancillary orders.

#### **PNG's Analysis was (Necessarily) Unreliable Due to Assumptions**

84. When PNG initially provided its calculations for a 5-year rate smoothing mechanism, it did so for illustrative purposes only, in an effort to be as responsive as possible to an IR request of the Panel. In doing so, it confirmed that it had not modelled its revenue requirements beyond the Test Period and, as a result, it was required to make simplifying assumptions in order to assess the scenario. PNG emphasized that "[a]ny changes to even one of the assumptions could lead to materially different results".<sup>84</sup> Likewise, as PNG submitted in its final argument, in light of these assumptions, it had concerns with the reliability of these calculations and urged the Panel to not assume they were reflective of actual impacts:

Despite answering the question in as fulsome and careful manner as possible, PNG continues to be concerned about the reliability of this analysis without a developed cost of service or demand forecast for these future years. PNG reiterates the point noted in its response to Panel IR 3.1, that any change to even one of these assumptions could lead to materially different results. There are many unknown and unanticipated factors that could occur in the future which are beyond PNG's control and these factors have the potential to materially affect PNG's demand and/or costs that underpin a determination of cost of service and revenue deficiency/sufficiency.

... As a result, PNG remains of the view that it cannot respond to these information requests that seek to set future rates other than illustratively and **urges the BCUC to not assume that these calculations will be reflective of the actual impacts.**<sup>85</sup>

85. PNG provides an example (described next, and arising since the Decision) of how changes in the simplifying assumptions will lead to drastically different results in this analysis. Should this Reconsideration Application proceed to a hearing, PNG could provide further examples.

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<sup>81</sup> Decision, pp. 35-36.

<sup>82</sup> Decision, Order #1.

<sup>83</sup> Decision, p. 36.

<sup>84</sup> Exhibit B-12, PNG Response to Panel IR No. 2, IR 3.1.

<sup>85</sup> PNG Supplemental Final Argument, paras. 12-13 (emphasis added).

This demonstrates why a rate smoothing order that extends beyond the Test Period cannot be reasonably implemented.

86. In its response to BCUC Panel IR 3.1, PNG produced a scenario whereby average rates were increased evenly over each of five years such that it results in a zero balance in the Rate Smoothing deferral account at the end of the five-year period. This resulted in an average annual rate increase of 17.2%. PNG reproduces the table provided in response to the IR as Table 1, below:

Table 1: Panel IR No.2, 3.1, Table 6 “Illustrative 5-Year Deferral Period (2025 to 2029) with Revenue Requirement, Smoothing Deferral and Cumulative Carrying Costs”

<b>(\$ million unless % specified)</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
Revenue Requirement	\$79.8	\$82.5	\$88.9	\$98.0	\$98.5
<b>Increase (YoY)</b>	<b>17.2%</b>	<b>17.2%</b>	<b>17.2%</b>	<b>17.2%</b>	<b>17.2%</b>
Rate Smoothing Deferral Account					
Beginning Balance	\$0.0	\$18.2	\$27.8	\$28.6	\$23.4
Additions	\$17.6	\$7.9	(\$1.3)	(\$7.2)	(\$24.2)
Carrying Costs	\$0.7	\$1.7	\$2.1	\$1.9	\$0.9
Ending Balance	\$18.2	\$27.8	\$28.6	\$23.4	\$0.0
Cumulative Carrying Costs	\$0.7	\$2.4	\$4.5	\$6.4	\$7.3

87. As set out above, PNG has not modelled its revenue requirements beyond Test Year 2027 and had made some simplifying assumptions to complete the scenario provided in Table 1. Any changes to even one of the assumptions could lead to materially different results. To demonstrate this, in Table 2 below, PNG produces a scenario with an additional assumption change: demand destruction. In Table 2, PNG assumes the US tariffs on forest products and aluminum have an impact on PNG’s industrial customers such that there is a 25% demand reduction of industrial load in 2025, that increases to 30% in 2027. This demand destruction would add \$12.3 million to the Industrial Customer Demand deferral account by the end of 2027 and would result in a \$7.8 million margin reduction in 2028. PNG believes that this is not an unreasonable example of the types of changes that could occur to the underlying assumptions, given the \$5.2 million of demand destruction that occurred in 2025 at lower rates.
88. Table 2 illustrates that if PNG’s rates were smoothed to 17.2% in 2025 through 2027, PNG would require average rate increases of 28.3% in each of 2028 and 2029 to recover the Rate Smoothing deferral account balance at the end of 2027 under this scenario:

Table 2: Illustrative 5-Year Deferral Period (2025 to 2029) with Revenue Requirement, Smoothing Deferral and Cumulative Carrying Costs Adjusted for Order G-270-25 and Industrial Demand Destruction

<b>(\$ million unless % specified)</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
Revenue Requirement	\$79.8	\$82.5	\$88.9	\$110.4	\$110.8
<b>Increase (YoY)</b>	<b>17.2%</b>	<b>17.2%</b>	<b>17.2%</b>	<b>28.3%</b>	<b>28.3%</b>
Rate Smoothing Deferral Account					
Beginning Balance	\$0.0	\$18.2	\$27.8	\$28.6	\$25.9
Additions	\$17.6	\$7.9	(\$1.3)	(\$4.7)	(\$26.8)
Carrying Costs	\$0.7	\$1.7	\$2.1	\$2.0	\$1.0
Ending Balance	\$18.2	\$27.8	\$28.6	\$25.9	\$0.0
Cumulative Carrying Costs	\$0.7	\$2.4	\$4.5	\$6.5	\$7.5

89. For illustrative purposes, this may be contrasted with the 17.2% estimated rate increase as per PNG's response to Panel IR 3.1, on account of a not unreasonable change in one underlying assumption. If the assumptions as shown in the illustrative 5-year deferral period provided in Table 2 were used and the Rate Smoothing deferral account was used to smooth rate increases evenly over the 5-year period, the average annual rate increase would rise from 17.2% to 19.7%. This is illustrated in Table 3 below.

Table 3: Illustrative 5-Year Deferral Period (2025 to 2029) with Revenue Requirement, Smoothing Deferral to Smooth Evenly and Cumulative Carrying Costs Adjusted for Order G-270-25 and Industrial Demand Destruction

<b>(\$ million unless % specified)</b>	<b>2025</b>	<b>2026</b>	<b>2027</b>	<b>2028</b>	<b>2029</b>
Revenue Requirement	\$79.8	\$82.5	\$88.9	\$110.4	\$110.8
<b>Increase (YoY)</b>	<b>19.7%</b>	<b>19.7%</b>	<b>19.7%</b>	<b>19.7%</b>	<b>19.7%</b>
Rate Smoothing Deferral Account					
Beginning Balance	\$0.0	\$16.9	\$23.3	\$18.5	\$15.9
Additions	\$16.2	\$4.7	(\$7.0)	(\$3.8)	(\$16.5)
Carrying Costs	\$0.7	\$1.7	\$2.1	\$1.3	\$0.6
Ending Balance	\$16.9	\$23.3	\$18.5	\$15.9	\$0.0
Cumulative Carrying Costs	\$0.7	\$2.4	\$4.5	\$5.8	\$6.4

90. The application of a five-year rate smoothing mechanism to achieve a desired rate increase is ultimately an artificial exercise given the assumptions required. The above example of a single, realistic change in the underlying assumptions results in a substantial change in the resultant rate increases, bringing the increases to within a few percentage points of the increases under an even three-year rate smoothing mechanism (approximately 23 percent per year,<sup>86</sup> without the financial risks created by extending the rate smoothing mechanism beyond the Test Period). Further, the fact that the simplifying assumptions utilized will change (and that this will likely materially impact the analysis) undermines a conclusion that the rates resulting from the BCUC-directed smoothing are just and reasonable under the UCA.

<sup>86</sup> Exhibit B-1, Application, s. 1.2.3.3; Decision, p. 33.

### The Financial Risks Were Not Sufficiently Considered

91. Further, the Panel erred in failing to sufficiently consider the financial risks to PNG, its customers and its shareholder of directing a 5-year rate smoothing mechanism that extends beyond the Test Period.
92. As a result of this direction, the Panel has left PNG without a means of collecting its full Revenue Requirements, instead deferring a portion beyond the current Test Period into 2028 and 2029. This deferral represents a sizeable portion of PNG's revenue requirements (approximately \$35 million, or approximately one-third of PNG's annual revenue requirements), exposing PNG to tangible, and likely substantial, additional financial risk.
93. More specifically, and as was submitted by PNG in evidence as part of this proceeding:
  - (a) as PNG will not be able to collect its full cost of service during the Test Period, it will have reduced cash flow during this period;
  - (b) this reduced cash flow will negatively impact PNG's debt metrics, requiring PNG to borrow more to fund its operations (at a cost to ratepayers), or obtain further equity injections from its shareholder. As the shareholder will not be earning a cash return on their equity investment in a timely manner, this will increase the risk to the shareholder and could impact PNG's ability to attract investment;
  - (c) impaired debt metrics risk a negative impact to PNG's debt rating and increase financial risk to the Company. As third-party rating agencies place specific emphasis on a utility's ability to recover its costs in a timely manner, the Decision (which defers recovery of a substantial portion of PNG's cost of service to a future period) could, on its own, trigger a change to PNG's debt rating; and
  - (d) this increased financial risk will also cause PNG's cost of capital to rise, negatively impacting the cost of both current and future debt and equity. This will make it harder to attract investment, and subject PNG to more restrictive covenants on its existing debt.<sup>87</sup>
94. Ultimately, the reduction in the Company's cash flow from delayed cost recovery results in additional debt requirements and overall higher costs, all of which may may impact PNG's ability to operate its business in a prudent manner. Further, this comes at a higher cost of service for ratepayers (creating a vicious cycle where increasing the cost of capital adds further pressure on the cost of service).<sup>88</sup> The Decision also improperly intrudes into core management responsibility.<sup>89</sup> By preventing PNG from collecting more than one-third of its annual revenue requirements, the Commission is obligating PNG to finance its costs.
95. The 5-year rate smoothing is also negative for ratepayers, in that it results in a sizeable cumulative rate impact (120.9 percent over 5-years) as compared to the 3-year rate smoothing proposed by PNG over the Test Period (71.4 percent over 3-years).<sup>90</sup>
96. The Panel also failed to consider the intergenerational equity issues created by a rate smoothing mechanism that extends beyond the Test Period in the Decision. As was

<sup>87</sup> Ex. B-11, PNG response to Panel IR No. 1, IR 2.1; Ex. B-12, PNG response to Panel IR No. 2, IR 3.1.

<sup>88</sup> Ex. B-11, PNG response to Panel IR No. 1, IR 2.1; Ex. B-12, PNG response to Panel IR No. 2, IR 3.1.

<sup>89</sup> *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106, paras. 55-56.

<sup>90</sup> Decision, p. 33.

submitted by PNG in its Supplemental Final Argument, deferring collection of its cost of service (that it reasonably needs today to enable PNG to provide safe and reliable service) for recovery from future ratepayers in a future period raises intergenerational equity concerns. This approach is simply borrowing from the future for the benefit of the present.<sup>91</sup>

97. These issues were not sufficiently considered and weighed by the Panel in reaching the Decision and ordering the five-year rate smoothing mechanism.

### **The Panel Erred in Binding a Future Panel**

98. Finally, PNG submits that the Panel exceeded its jurisdiction in ordering that PNG set its rates based on a smoothing scenario that extends beyond the current Test Period into future periods. In doing so, the Panel directed PNG to “[a]ddress the disposition of the Rate smoothing deferral account balance at December 31, 2027 in the next RRA”.<sup>92</sup>
99. In its Supplemental Final Argument, PNG raised its concern that a rate smoothing mechanism that spreads out PNG’s cost of service into future periods (beyond the Test Period), would improperly fetter the discretion of future panels. This jurisdictional issue was not addressed by the Panel in the Decision.
100. An application under the rate setting provisions of the *UCA* (ss. 58-61) requires the Commission to assess proposed rates as just and reasonable based on all of the evidence in the record before it. Section 75 of the *UCA* is explicit that the Commission must consider each application on its own merits, providing that, “[t]he commission must make its decision on the merits and justice of the case, and is not bound to follow its own decision”. This is reflective of the common law principle that administrative tribunals cannot fetter their own discretion, which principle has been routinely confirmed by the BCUC.
101. For example, the Federal Court of Canada described the principle as follows on judicial review of a decision of the *Bell Canada v. Canada (Attorney General)*, 2011 FC 1120, para. 88:

As a matter of law ... it is my view that while the CRTC may refer to and take guidance from its earlier decisions, those decisions cannot dictate its subsequent decisions. The CRTC is not bound by precedent and has a legal obligation not to fetter its discretion. As stated in Macauley and Sprague’s *Practice and Procedure Before Administrative Tribunals*:

... the notion of *stare decisis* is not applicable in the administrative sphere. Agencies are not only at liberty not to treat their earlier decisions as precedent, they are positively obligated not to do so. [emphasis added]

The principle that an administrative tribunal cannot use its previous decisions to fetter its discretion was established in *Hopedale Developments Ltd. v Oakville (Town)* (1965), 47 DLR (2d) 482 (ONCA) at 486. The Ontario Court of Appeal held in that case that it would have been an error of law for the Ontario Municipal Board to use precedent to limit the number of issues that it needed to address. Administrative tribunals are permitted to rely on principles

<sup>91</sup> Ex. B-12, PNG response to Panel IR No. 2, IR 3.1.

<sup>92</sup> Decision, p. 36.

articulated in previous decisions as long as the tribunal gives “the fullest hearing and consideration to the whole problem before it.”

The prohibition on exclusive reliance by an administrative tribunal on previous decisions includes not only factual and policy decisions but also legal determinations and is essential to ensure that administrative tribunals have the flexibility to respond to new circumstances on a case-by-case basis. The need for flexibility is particularly acute in the case of policy and factual determinations

...<sup>93</sup>

102. Ultimately, the Panel’s decision in this respect operates to spread PNG’s cost of service into future periods beyond the 2025-2027 Test Period. This places a decision before a future panel regarding the recovery of costs from a prior period (the current Test Period), that were not found to be imprudent, but that were not found to be recoverable in that prior period. The Decision suggests that this future panel will be bound to accept these (prudent and reasonable) costs, improperly fettering its discretion. This would limit the ability of the future panel to consider issues like intergenerational equity, and how the costs ought to be weighed against the resulting rate impact for the future period. Deferring these costs into a future period may put the future panel in a challenging position.
103. Alternatively, if the Panel is not intending to fetter the discretion of a future panel (i.e. it is intending to leave it open for the future panel to determine whether or not PNG ought to recover the outstanding balance in the Rate Smoothing deferral account as of December 31, 2027, and how this balance ought to be addressed), this creates significant risk for PNG as it incurs these costs, and results in rates that are unjust and/or unreasonable as they are insufficient to yield fair and reasonable compensation.
104. Given the sizeable amount of the deferral beyond the Test Period, the future panel may be faced with a revenue requirements application that seeks rate increases as substantial as put forward in the Underlying Application, leaving instead the future panel in a position where it must balance mitigating customer rate impact and managing the risks related to deferring revenue requirements, much like this Panel.

## **B. The Material Impact of the Decision**

105. The Panel’s decision to defer recovery of a sizeable portion of PNG’s revenue requirements outside the Test Period and into 2028 and 2029 clearly has a material and direct impact on PNG. PNG relies on the grounds for reconsideration set out above, which also discuss the material impact and risks that arise from a 5-year rate smoothing mechanism.
106. The Decision creates significant financial risk for PNG in terms of reducing cash flow, increasing risks of recovery, negatively impacting PNG’s credit rating and increasing PNG’s cost of borrowing. This risk is also amplified by the uncertainty caused by the illustrative, simplifying assumptions that were necessary to calculate the impacts of a 5-year rate smoothing scenario provided in response to Panel IR 3.1.<sup>94</sup>
107. Further, the Decision has a material impact in that it results in substantially higher rate increases for customers on a cumulative basis (120.9 percent over 5-years) as compared to the 3-year rate smoothing proposed by PNG over the Test Period (71.4 percent over 3-

<sup>93</sup> *Bell Canada v. Canada (Attorney General)*, 2011 FC 1120 at para 88.

<sup>94</sup> Ex. B-12, PNG Response to Panel IR No. 2, IR 3.1.

years), which would leave the deferral account with a nil balance at the end of the Test Period.

### C. The Remedy Sought

108. In this Reconsideration Application, PNG seeks to vary the Decision so that PNG is directed to: (a) set basic and delivery charges for the Test Period based on the 3-year rate smoothing scenario outlined by PNG in its Application, (b) provide supporting calculations for the Test Period as part of the compliance filing that PNG is directed to submit to the BCUC, and (c) establish a Rate Smoothing deferral account to set the Test Period rates based on the 3-year rate smoothing scenario.
109. PNG remains of the view that the preferable rate smoothing mechanism in all of the circumstances is what was proposed in the Underlying Application (resulting in residential rate increases year-over-year of 27.8 percent in 2025 and 2026, and 5 percent in 2027). However, given the significant risks associated with deferring a substantial portion of PNG's revenue requirements beyond the Test Period, PNG suggests that smoothing beyond the Test Period is not lawful (and, it believes, it would be an error in fact, law or jurisdiction for the BCUC to make such an order). As such, a rate smoothing scenario that utilizes a three-year time period is appropriate, even if different from the scenario sought by PNG in the Underlying Application. For example, in the Underlying Application, PNG also explored a 3-year rate smoothing mechanism with even annual impacts (resulting in an average rate increase of 23.3% year-over-year for the Test Period).

### CLARTIFICATION REGARDING OMA&G EXPENSES

110. While PNG does not seek reconsideration and variance of Order G-270-25 with respect to the decisions made on OMA&G expenses, it does seek clarification from the BCUC on one point.
111. In the Decision, the BCUC presented "Table 4: PNG OMA&G Expenses (\$'000)" representing PNG's OMA&G expenditures as submitted in the PNG-West Division 2025-2027 Revenue Requirements Application (2025-2027 RRA), as follows:<sup>95</sup>

Table 4: Net OMA&G Expense Items (\$000s)

Expense	2024 BCUC Approved	Test Year 2025	Test Year 2026	Test Year 2027
Operating, net of company use gas	16,332	16,837	17,570	18,446
Maintenance	787	871	913	941
Administrative and General, net of cost adjustments	14,657	15,514	15,950	16,763
<b>Total OMA&amp;G, gross</b>	<b>31,776</b>	<b>33,222</b>	<b>34,433</b>	<b>36,150</b>
Shared service cost recovery from PNG(NE) for operating, administrative and general	(4,927)	(5,474)	(5,647)	(5,951)
Transfers to capital for operating, administrative and general	(2,324)	(2,385)	(2,650)	(2,429)
<b>Total OMA&amp;G, net</b>	<b>24,525</b>	<b>25,363</b>	<b>26,136</b>	<b>27,770</b>
<b>Increase as compared to prior year (%)</b>		<b>3.42%</b>	<b>3.05%</b>	<b>6.25%</b>

<sup>95</sup> Decision, p. 8.

112. In the Decision, the BCUC states that “PNG has not justified the need to increase its OMA&G expenses beyond 2 percent per year”,<sup>96</sup> and issued the following directive to PNG:

... PNG is directed to update its Test Period revenue requirements and rates in its compliance filing for this proceeding to reflect the following in net OMA&G expenses: (a) the adjustments and corrections to OMA&G expenses identified by PNG during the proceeding and (b) any necessary, additional adjustments to limit annual increases to net OMA&G expenses to a maximum increase of 2 percent each year relative to the prior year forecast.<sup>97</sup>

113. Illustratively, based on amounts presented in Table 4 (above), limiting Test Period net OMA&G expenses to a 2 percent annual increase relative to the 2024 BCUC-approved net OMA&G expenses of \$24.525 million and subsequent test year forecast amounts, net OMA&G in Test Year 2025 would need to be reduced by \$348,000 to \$25.015 million, OMA&G in Test Year 2026 would need to be reduced by \$620,000 to \$25.515 million and OMA&G in Test Year 2027 would need to be reduced by \$1.745 million to \$26.026 million. These implied reductions to OMA&G are summarized in Table 5:

Table 5: Implied Net OMA&G Reductions in Test Period (\$000s)

Expense	2024 BCUC Approved	Test Year 2025	Test Year 2026	Test Year 2027
<b>Total OMA&amp;G, net</b>	<b>24,525</b>	<b>25,363</b>	<b>26,136</b>	<b>27,770</b>
2.00% annual increase	24,525	25,015	25,515	26,026
Implied OMA&G change		(348)	(620)	(1,745)

114. Further, Table 4 illustrates that the determination of net OMA&G is also impacted by: (a) shared services cost recoveries from PNG(NE), and (b) transfers to capital.
115. As described below, changes to the underlying OMA&G expenses and to capital expenditures have a circuitous, flow-through impact on the computation of “net” OMA&G.
116. Specifically, the reductions to OMA&G expenses (including both identified adjustments and corrections and necessary additional adjustments to achieve annual increases of 2%) results in a reduction in shared service cost recoveries from PNG(NE), which has the effect of offsetting and materially mitigating the implied decreases in net OMA&G expenses.
117. Further, the Decision denied recovery in rates of 50 percent of the Test Period forecast integrity management capital expenditures of \$45.150 million (or \$22.575 million)<sup>98</sup> and did not accept PNG’s 2027 forecast capital expenditures related to the MP 239.75 Limonite Creek Encroachment and MP 332.85-334.64 capital project costs totaling \$8.153 million.<sup>99</sup> PNG observes that certain transfers to capital (i.e. costs related to corporate and field management support and oversight of capital programs) are allocated amongst the four PNG-West and PNG(NE) divisions based on their proportionate share of consolidated capital expenditures. As such, the cumulative reduction in PNG-West Test Period capital expenditures by \$30.728 million (\$22.575 million + \$8.153 million) results in a reduction in

<sup>96</sup> Decision, p. 11.

<sup>97</sup> Decision, p. 11.

<sup>98</sup> Decision, p. 22. PNG notes that it seeks reconsideration of this aspect of the Decision in this Reconsideration Application.

<sup>99</sup> Decision, p. 25.

transfers to capital for PNG-West, which also has the effect of offsetting and materially mitigating the implied decreases in net OMA&G expenses. PNG observes that the impacts of the integrity management capital expenditure reductions are exacerbated by the timing of the BCUC Decision and the fact that PNG had fully deployed its integrity management capital plan for 2025, leaving only \$8.695 million of integrity capital available for the 2026 and 2027 period, and which PNG anticipates fully utilizing in 2026.

118. Table 6 below highlights the impacts of the directed OMA&G expense and capital expenditure reductions on gross OMA&G expenses, shared service cost recoveries and transfers to capital:

Table 6: Impacts to Net OMA&G Expense of Directed Adjustments (\$000s)

Expense	2024 BCUC Approved	Test Year 2025	Test Year 2026	Test Year 2027	Cumulative Impact
<b>Total OMA&amp;G, gross - original</b>	<b>31,776</b>	<b>33,222</b>	<b>34,433</b>	<b>36,150</b>	
Implied OMA&G reduction	-	(348)	(620)	(1,745)	(2,713)
<b>Total OMA&amp;G, gross - adjusted</b>	<b>31,776</b>	<b>32,874</b>	<b>33,813</b>	<b>34,405</b>	
Shared service cost recovery from PNG(NE) for operating, administrative and general	(4,927)	(5,474)	(5,647)	(5,951)	
Flow-through impacts		33	50	9	92
Transfers to capital for operating, administrative and general	(2,324)	(2,385)	(2,650)	(2,429)	
Flow-through impacts		31	(34)	437	434
<b>Total OMA&amp;G, net</b>	<b>24,525</b>	<b>25,079</b>	<b>25,531</b>	<b>26,471</b>	

119. Table 7 below illustrates the flow-through impacts of the directed changes to OMA&G expense on the shared service cost recovery and the transfers to capital. Table 7 is similar to Table 4, and implies that further OMA&G expense reductions of \$525,000 would be required to achieve a net OMA&G expense increase of 2% per year:

Table 7: Net Change to Net OMA&G Expense Items (\$000s)

Expense	2024 BCUC Approved	Test Year 2025	Test Year 2026	Test Year 2027	Cumulative Impact
<b>Total OMA&amp;G, net</b>	<b>24,525</b>	<b>25,079</b>	<b>25,531</b>	<b>26,471</b>	
2.00% annual increase	24,525	25,015	25,515	26,026	
<b>Implied further OMA&amp;G reduction</b>		<b>(64)</b>	<b>(16)</b>	<b>(446)</b>	<b>(525)</b>

120. Tables 6 and 7 illustrate the circuitous impacts of the directed adjustments, as a further reduction to gross OMA&G expenses would again have a flow-through impact to shared service cost recoveries and transfers to capital. Further impacts and adjustments to gross OMA&G expenses, the shared service cost recovery and the transfers to capital will result from each iteration of this exercise.
121. PNG believes the foregoing to be an unintended consequence which had not been anticipated in the BCUC's directive to limit annual increases to net OMA&G expenses to a maximum increase of 2 percent each year relative to the prior year forecast. PNG seeks confirmation from the BCUC that its intention was for PNG to implement OMA&G expense reductions of \$2.713 million as implied per Table 5, rather than OMA&G expense reductions in excess of \$3.328 million (\$2.713 million plus \$0.525 million) as per Tables 6 and 7.

122. PNG submits that the cost cutting required to achieve the incremental \$0.525+ million in reductions in net OMG&A expense will impair PNG's ability to safely and reliably serve its customers.

### **PROPOSED RECONSIDERATION PROCESS**

123. Rule 30.04 of the BCUC Rules sets out regulatory processes that are available to the BCUC for a reconsideration hearing, as follows:

The BCUC will determine the regulatory process for the reconsideration hearing, which may include, but is not limited to: (a) whether the hearing will be wholly, or in part, written, oral, or a combination thereof; (b) a determination as to whether any new evidence or evidence of a change of circumstances will be permitted on the reconsideration hearing and the timing of submissions on these issues; (c) the scheduling of oral hearings, if any; (d) the scheduling of arguments, if any; and (e) any other procedural directions the BCUC considers appropriate.

124. In light of the materiality of the impact of the Decision, and its affect on upcoming utility expenses and planned works (including PNG's forecast integrity management expenditures, which are largely carried out over the spring/summer months), PNG proposes an efficient and focused reconsideration process to allow these matters to be considered in a timely, but fulsome manner.
125. With respect to reconsideration of the Panel's decision regarding integrity management expenditures, there is time pressure on having certainty on the amount approved for recovery in rates, in order to allow PNG to plan for, and commence, 2026 integrity management activities. PNG submits that there is sufficient evidence before the BCUC to conclude that its Decision ought to be varied to permit PNG to recover in rates the full \$45.15 million in forecast integrity management expenditures for the Test Period. The evidence on the record in the underlying proceeding is summarized in this Reconsideration Application, and this has now been supplemented by further evidence from the BCER (see Schedule "A"), which arose subsequent to the proceeding. We note that, in the underlying proceeding, the interveners BCOAPO and RCIA supported PNG's forecast expenditures related to the integrity management capital expenditures over the Test Period, on the basis that they are necessary to establish a reasonable safe operating pressure, and to address BCER orders and requirements.<sup>100</sup> PNG submits that further hearing process is not necessary and the BCUC may vary the Decision on integrity management expenditures without further process.
126. In the alternative, if the BCUC concludes that it does not have sufficient information to vary this decision without further process or that further reconsideration is required, PNG proposes a written hearing process being undertaken.
127. With respect to PNG's application for reconsideration of the Panel's decision on the rate smoothing mechanism, PNG proposes that the BCUC set a written hearing process.
128. PNG recommends that any written hearing process include one round of BCUC information request, and final arguments. Additionally, should the BCUC determine that a written hearing process is necessary on integrity management expenditures, PNG requests that the process also include an opportunity for an Evidentiary Update (with respect to the

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<sup>100</sup> Decision, p. 22.

Integrity Management Capital Expenditures, the BCER orders and the impact of a 50 percent reduction in expenditures), to include the new and further evidence outlined in this Reconsideration Application.

### **STAY OF COMPLIANCE FILING**

129. Finally, in Order G-270-25, PNG was directed to submit a compliance filing with the BCUC by January 14, 2026, which was to include revised regulatory schedules, updated tariff pages reflecting the permanent approvals and supporting calculations in a working Excel spreadsheet.
130. On December 16, 2025, PNG wrote to the BCUC to indicate that it intended to file a reconsideration application and, as part of this this application, would be seeking an order suspending the compliance filing deadlines until the reconsideration process is concluded. In the interim, PNG sought an extension of the compliance filing deadline. On December 18, 2025, the BCUC issued Order G-309-25, extending the date for the compliance filing from January 14, 2026 to: (a) within two weeks following the BCUC's decision on the suspension request, or (b) January 31, 2026 if PNG has not filed the suspension request by that date.
131. Pursuant to Rule 32 of the BCUC Rules, this Reconsideration Application does not act to automatically stay or suspend the operation of the Decision; however, the BCUC has the discretion to stay the operation of all or part of the Decision pending the outcome of the reconsideration:
- 32.01 An application for reconsideration of a decision does not automatically stay or suspend the operation of the decision.
- 32.02 The BCUC may, in its discretion or on application, stay the operation of the decision in the original proceeding, or part thereof, pending the outcome of the reconsideration on terms the BCUC considers appropriate.
132. PNG seeks a stay of the requirement to file this compliance filing, pending the determination of the Reconsider Application, pursuant to Rule 32.02 of the BCUC Rules.
133. In this Reconsideration Application, PNG seeks reconsideration and variance of two aspects of the Decision that will directly impact the content of the compliance filing: the amount of integrity management capital expenditures to be included in the calculations, as well as the rate smoothing mechanism to be utilized.
134. Further, to attempt to prepare a compliance filing to set permanent rates on the basis of the current Decision would be problematic. PNG has been directed to set basic charges and delivery charges for 2025, 2026 and 2027 based on the 5-year rate smoothing scenario outlined in Panel IR 3.1 (Exhibit B-12).<sup>101</sup> However, PNG completed the analysis under this smoothing approach by using simplifying assumptions that were provided as illustrative only, in order to be as responsive as possible to the Panel IR. These assumptions necessarily impact the reliability of PNG's analysis and mean that even minor and likely changes to the assumptions could have a material impact on the outcome of the smoothing. PNG respectfully submits that this is not an appropriate input into setting rates. As was set out above, in Panel IR 3.1, PNG made a simplifying assumption that there would be no

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<sup>101</sup> Decision, Order #1.

industrial demand destruction in 2028 and 2029, which is likely not realistic and impacts the calculations.

135. Additionally, the Decision itself has resulted in the assumptions in Panel IR 3.1 no longer making sense. For example, in the Decision PNG was denied recovery of 50 percent of its capital integrity spending. If this decision is not varied (as PNG seeks in this Reconsideration Application), it is inevitable that significant additional capital spending would be required in 2028 and 2029 to compensate for any deferred work (including spending that would likely be required to get PNG's pipelines back up to 800 psig operating pressure again). In Panel IR 3.1, PNG had assumed a marginal 2 percent capital increase, which is now unsupported in light of the Decision.
136. Ultimately, without having long-range financial projections for 2028 and 2029, PNG cannot accurately predict revenue requirements for those periods, nor can it prepare the compliance filing to reflect reasonable and appropriate assumptions for future rate needs.
137. PNG seeks to pause the compliance filing requirement until three weeks following the BCUC's decision on this Reconsideration Application, to allow PNG to prepare the necessarily paperwork.

#### **REQUEST TO INCREASE INTERIM RATES**

138. In light of PNG's request for a stay of its compliance filing, and in order to avoid a buildup of under-recovered amounts while this Reconsideration Application is considered, PNG seeks an increase its interim rates, in order to reflect how the BCUC directed rates to be set in this Decision.
139. Attached at **Schedule "B"** is supporting information, including PNG's high-level rationale for the request, illustrative revenue deficiency summaries, certain of the regulatory and rate schedules, bill comparisons, and additional analysis.
140. PNG seeks implementation of these interim rates, effective as of March 1, 2026.

#### **CONCLUSION**

141. In conclusion, PNG respectfully submits that it has established reasonable grounds for reconsideration of the Decision, with respect to both the integrity management capital expenditures and the rate smoothing mechanism, and this Reconsideration ought to proceed to a hearing, with a written hearing process.
142. PNG further submits that a stay be granted, pending the outcome of this reconsideration, for PNG to file its compliance filing, until three weeks following the BCUC's decision.
143. PNG also requests that the BCUC provide the clarification requested regarding its direction on OMA&G expenses.
144. Finally, PNG seeks to have its interim rates increased to reflect the Decision.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

January 23, 2026

Dated



Erica Miller, Farris LLP, counsel for PNG

## SCHEDULE "A"

**Erica Miller**

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**From:** Koosmann, Nicole <[Nicole.Koosmann@bc-er.ca](mailto:Nicole.Koosmann@bc-er.ca)>

**Sent:** January 8, 2026 9:21 AM

**To:** Kyle Keith <[kkeith@png.ca](mailto:kkeith@png.ca)>

**Cc:** Parsonage, Kevin <[Kevin.Parsonage@bc-er.ca](mailto:Kevin.Parsonage@bc-er.ca)>

**Subject:** PNG Safety & Loss Management, Integrity

Hello Kyle,

The Pipeline regulation and CSA Z662:23 require permit holders to have a Safety and loss Management System (SLMS), which includes requirements for pipeline integrity management. This includes requirements to proactively identify, assess and mitigate threats to pipeline integrity throughout the life of the pipeline.

With respect to piping imperfections, including corrosion, cracking and dents, permit holders must assess the potential for imperfections to be present, establish a schedule of inspections including inline inspections and direct inspections (digs) to assess the presence and extent of imperfections and to calibrate the results of inline inspections. Where imperfections exceed the thresholds allowed in CSA Z662:23, the repairs must be completed in accordance with the standard.

Permit holders are required to make conservative assumptions when selecting imperfections for repair and when modeling the growth imperfections between inspections to ensure the continued safe and reliable operation of the pipeline system. Any postponed, or cancelled, inline inspections will require engineering assessments to review the risks and take any additional actions to mitigate the risks. Where conditions arise that present hazards, immediate steps shall be taken to manage the hazards.

The regulator may take actions to restrict the operating pressure or require full shut-in where there are concerns that imperfections may compromise the safe and reliable operation of a pipeline. In the case of Pacific Northern Gas (PNG), in January 2021 the regulator issued an order restricting operating pressures in the pipeline system. Operating pressure restrictions have been regularly adjusted as inspections, repairs and integrity assessments were completed. The most recent adjustment was an increase in the operating pressure of certain segments of the pipeline system due to repairs completed in the 2025 field season. However, PNG is still under order with the BCER for pressure restrictions for specific pipeline segments.

The regulator has recently become aware that funding for future integrity activities has been limited such that certain planned inspection and repair activities for the 2026 and 2027 calendar years will not be completed. As such, the regulator requires PNG to complete engineering assessments of the impacted pipeline segments to assess the impact of deferred activities on the integrity of the pipeline system. The regulator may implement further reductions in pipeline operating pressures as a result of the deferred inspection and repair activities.

With respect to geohazards, the regulator is concerned that a “just in time” approach is being taken to mitigate geohazards. In 2025, PNG completed two emergency repairs at the Kitimat River crossing and the Mile Post 353.5 slide and shut-in a section of exposed pipe at Limonite Creek. The regulator is also aware that risk of many identified geohazards have not been fully assessed with respect to the continued safe and reliable operation of the pipeline system.

This approach does not meet the requirements of the SLMS to proactively identify, assess, and mitigate threats to pipeline integrity throughout the life of the pipeline. As a result, the regulator issued orders in 2025 for PNG to complete repairs to and provide assessments of certain geohazards along the pipeline system. The regulator will continue to monitor PNG’s management of geohazards and may issue additional orders if needed.

Regards,



**Nicole Koosmann** P.Eng., P.M.P.  
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*We acknowledge and respect the many First Nations, each with unique cultures, languages, legal traditions, and relationships to the land and water, on whose territories the British Columbia Energy Regulator operates.*

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## SCHEDULE "B"

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. (together, PNG) hereby apply to the British Columbia Utilities Commission (BCUC) to grant approval, pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (UCA), to revise the basic and delivery charges currently established for 2026, on an interim basis, for each of the PNG-West, Fort St. John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions.

As outlined in the sections that follow, this request arises from PNG's applications to the BCUC for reconsideration of certain directives issued in Orders G-270-25 and G-284-25 and the associated decisions (Decisions) pertaining to the 2025-2027 Revenue Requirements Applications (2025-2027 RRAs) for the PNG-West division and the FSJ/DC and TR divisions, respectively (Reconsideration Applications).

### **Background**

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On December 3, 2024, PNG filed a request for the BCUC to grant interim approval of its basic charges, delivery charges and Revenue Stabilization Adjustment Mechanism (RSAM) rate riders, effective January 1, 2025, for each PNG division. By Order G-333-24 dated December 12, 2024, the BCUC approved PNG's request for approval of its basic charges, delivery charges and RSAM rate rider on an interim and refundable or recoverable basis, effective January 1, 2025 (2025 Interim Rates) for each of the PNG divisions.

On April 2, 2025, PNG filed its 2025-2027 RRAs for each division with the BCUC seeking approval of its 2025, 2026 and 2027 basic charges and delivery rates on a permanent basis, and approval of its 2025 RSAM rate riders on a permanent basis, effective January 1, 2025. On April 22, 2025, the BCUC issued Order G-101-25 and Order G-102-25 which, among other things, approved the request to revise basic charges, delivery charges and RSAM rate rider on an interim and refundable or recoverable basis, effective May 1, 2025 (2025 Amended Interim Rates) for each of the PNG-West division and the FSJ/DC and TR divisions, respectively.

On November 24, 2025, the BCUC issued Order G-270-25 and the accompanying decision on the PNG-West division 2025-2027 RRA, and on December 4, 2025, the BCUC issued Order G-284-25 and the accompanying decision on the FSJ/DC and TR division 2025-2027 RRA. Both Orders G-270-25 and G-284-25 included directives for PNG to maintain the 2025 Amended Interim Rates (per Directive 2 and Directive 5, respectively) into 2026 pending the BCUC's acceptance of the compliance filings that PNG was also directed to submit (per Directive 7 and Directive 9, respectively).

On December 8, 2025, the BCUC issued Orders G-289-25 and G-290-25 approving PNG's requests, dated November 21, 2025, to amend its RSAM rate riders for the PNG-West division and the FSJ/DC and TR divisions, respectively, on a permanent basis, effective January 1, 2025.

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On December 16, 2025, PNG filed a letter with the BCUC requesting an extension of the compliance filing deadline pursuant to Directive 7 of Order G-270-25 and Directive 9 of Order G-284-25 of the BCUC's decision regarding PNG's 2025-2027 RRAs for the PNG-West Division and the FSJ/DC and TR Divisions, respectively. In its submission, PNG explained it intended to file applications seeking reconsideration of certain elements of both 2025-2027 RRA Decisions, and that in the Reconsideration Applications it would be seeking an order to suspend the compliance filings until the reconsideration process has concluded. On December 18, 2025, the BCUC issued Order G-309-25 approving the requested extensions.

On January 23, 2026, PNG submitted an application to the BCUC for reconsideration of certain directives contained in Order G-270-25 and the accompanying Decision pertaining to the 2025-2027 RRA for the PNG-West division, and anticipates submitting an application to the BCUC for reconsideration of certain directives contained in Order G-284-25 and the accompanying Decision pertaining to the 2025-2027 RRA for the FSJ/DC and TR divisions on January 27, 2026.

**Request for Approval to Revise 2026 Interim Rates**

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Considering the procedural history summarized above, PNG respectfully requests that the BCUC approve revisions to the interim basic charges and delivery charges currently in effect for 2026 for the PNG-West, FSJ/DC and TR divisions.

**Basis for the Request**

As detailed in this submission, several developments since the establishment of the existing interim rates support the revision of interim 2026 rates at this time:

- 1) A rate increase is indicated for 2026 under the BCUC's 2025-2027 RRA Decisions. Under Orders G-270-25 and G-284-25, the indicative provisional revenue requirements for each PNG division, when translated into rates, reflect an increase for 2026 relative to the levels embedded in the currently-approved Amended Interim Rates. Although both Decisions directed that the Amended Interim Rates were to continue until acceptance of PNG's required compliance filings, the indicative provisional 2026 revenue requirements from implementing the Decisions indicate that higher rates will, in any event, be necessary for the 2026 test year.
- 2) The proceeding to consider PNG's Reconsideration Applications is expected to take time. On January 23, 2026, PNG filed an application requesting reconsideration of certain directives contained in Orders G-270-25 and anticipates filing an application requesting reconsideration of certain directives contained in G-284-25 on January 27, 2026. Given the scope and complexity of the issues raised, and consistent with typical

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BCUC reconsideration timelines, PNG anticipates that the process may take some time. During this time, PNG is required to continue operating under interim 2026 rates that do not reflect the indicative provisional 2026 revenue requirements, nor the revisions that may ultimately result from the reconsideration outcomes.

- 3) Maintaining current interim rates will lead to a buildup of unrecovered amounts. If interim rates remain unchanged until the reconsideration process concludes and compliance filings are subsequently accepted, the resulting under-collection of 2026 revenue requirement amounts will need to be recovered from customers over the balance of the Test Period. This could result in larger rate adjustments which could be mitigated by implementing revised interim rates at this juncture that better reflect the indicative provisional 2026 revenue requirements pending the outcome of the reconsideration process.

### **Implementation of Decisions and Determination of Provisional Revenue Requirements**

To support the requested revisions to the 2026 interim rates, PNG has modelled the directives in the BCUC's 2025–2027 RRA Decisions to determine the indicative provisional revenue requirements and the proposed rate changes.

As a qualification to the foregoing – subject to the outcome of the Reconsideration Applications – for PNG-West, PNG has put forward revised interim rates based on the modelling filed in response to BCUC Panel IR 3.1 (Exhibit B-12). That modelling demonstrated annual rate increases of 17.2% under a five-year revenue deficiency smoothing methodology. PNG has relied on this indicative annual rate increase given that it is unable to finalize appropriate assumptions for the fourth and fifth years of the smoothing period, beyond the simplifying assumptions adopted in its response to Panel IR 3.1, until after the reconsideration process is concluded.

### **Supporting Information Demonstrating Implementation of the BCUC's Directives**

PNG is providing comprehensive and transparent information to support the requested revisions to the 2026 interim rates. The materials included with this filing consist of:

- 1) Cost of Service Comparisons

Cost of service comparison schedules are provided to illustrate the computation of the provisional revenue deficiency (or sufficiency) for each PNG division, as described above. These schedules highlight the variance between the provisional test year revenue requirements and the test year revenue requirements as per the 2025-2027 RRAs that support the approved Amended Interim Rates presently in place.

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2) Allocation of Revenue Deficiencies or Sufficiencies

Schedules are provided to illustrate how the Test Year 2025 and Test Year 2026 revenue deficiencies or sufficiencies are allocated to each customer class as well as the resultant rate changes arising from the implementation of BCUC Orders G-270-25 and G-284-25 and their respective Decisions.

3) Revised Rate Schedules

Updated proposed 2026 interim rate schedules for the PNG-West, FSJ/DC, and TR divisions, showing the proposed revisions to the interim basic charges and delivery charges for which approval is being sought in this submission. All other rate elements are also illustrated to provide a complete depiction of 2026 customer rates.

4) Updated Regulatory Schedules

Revised versions of certain of the regulatory schedules directed for filing in the 2025–2027 RRA Decisions, including summary schedules supporting income and return, rate base, income taxes, common equity and return on capital.

5) Customer Bill Impacts

Illustrative bill impacts for typical residential and small commercial customers in each division, comparing:

- current Amended Interim Rates;
- proposed revised 2026 interim rates reflecting the indicative provisional revenue requirements and indicative annual rate increases; and
- variance amounts and percentages.

These impacts demonstrate that the resulting rates translate the indicative, provisional revenue requirements into customer rates in the manner directed by the BCUC.

**Deferral of Detailed Testing at This Stage of the Proceeding**

PNG submits that, while it is providing detailed supporting calculations and schedules, it is not appropriate to undertake a full testing of these materials at this stage because:

- The proposed rates are interim only, and remain subject to refund or recovery pending the outcome of the Reconsideration Applications;
- The provisional 2026 revenue requirements themselves may be further revised by the BCUC once the reconsideration process concludes. As described previously, notably for PNG-West, certain assumptions are illustrative and PNG is not able to defend these simplifying assumptions as being appropriate for setting rates at this time; and

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- Regulatory efficiency favours avoiding duplicative review, given that a fulsome review will be undertaken of the compliance filings to be submitted following the reconsideration process.

### **Relief Requested**

Accordingly, PNG respectfully requests that the BCUC:

- 1) Approve 2026 revised interim basic charges and delivery charges for the PNG-West, FSJ/DC, and TR divisions, pursuant to sections 58 to 61, 89 and 90 of the UCA based on the provisional 2026 revenue requirements prepared in accordance with the directives of Orders G-270-25 and G-284-25 and the accompanying Decisions;
- 2) Confirm that the revised rates will continue to be interim on a refundable or recoverable basis, pending the outcome of PNG's Reconsideration Applications and the BCUC's subsequent acceptance of any required compliance filings;
- 3) Accept the supporting calculations and schedules for the limited purpose of establishing revised 2026 interim rates, without detailed testing at this stage; and
- 4) Grant any further orders or directions that the BCUC considers necessary or appropriate in the circumstances.

### **Proposed Implementation Date**

To mitigate the buildup of unrecovered amounts, PNG seeks to implement the revised interim rates effective March 1, 2026. This requires BCUC approval no later than Wednesday, February 18, 2026, to ensure adequate time for billing system updates. If this approval timeline cannot be met, PNG will implement the revised interim rates effective April 1, 2026.

### **Supporting Documentation**

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To facilitate the BCUC's review, PNG has included several schedules that are customarily submitted in support of its RRAs and proposed rate changes. These schedules are discussed in detail below.

### **Cost of Service Comparisons**

Included as **Exhibit A**, PNG has provided cost of service comparisons for each PNG division illustrating the derivation of the revenue deficiency (or sufficiency) for each test year, that compare the provisional revenue deficiency (or sufficiency) , prepared as described above, to those presented in the 2025-2027 RRAs that supported the approved Amended Interim Rates presently in place. PNG observes that cost of service comparisons of this nature are

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customarily included in the RRAs to illustrate the derivation of test year revenue deficiencies or sufficiencies.<sup>1</sup>

Notable variances indicated for each division are as follows:

- PNG-West:
  - Net reductions to OMG&A to reflect both adjustments and corrections identified in the course of the proceeding and PNG's interpretation of the BCUC's directive to cap net OMG&A expense increases at 2% over the prior period, and also the flow-through impacts of the BCUC's PNG-West Decision that reduce PNG-West shared service cost recoveries from PNG(NE).
  - Flow-through impacts on transfers to capital primarily because of the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and the directives in the Decision, including disallowance of certain capital expenditures related to integrity activities and geohazards.
  - Reductions to depreciation resulting from the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and directives in the Decision.
  - Changes in amortization because of the directive to shift the amortization of the Large Volume Industrial deferral account (LVIDA) balance from 2025 to 2027.
  - Flow-through impacts of the foregoing adjustments on income taxes, return on equity and interest expense.
  - Reduction to Company use gas cost reflecting the adjustment identified in the course of the proceeding for the elimination of the BC Carbon Tax effective April 1, 2025.
  - Flow-through impacts of the foregoing adjustments on margin.
  - Flow-through impacts on the Rate Smoothing deferral account arising from the foregoing adjustments and the directive in the Decision for PNG to smooth rate increases over a period of five years (implemented as described above).
- FSJ/DC:
  - Net reductions to OMG&A to reflect both adjustments and corrections identified in the course of the proceeding, and also the flow-through impacts that reduce

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<sup>1</sup> For example, see Tables 7, 8 and 9 of the PNG-West 2025-2027 RRA, Tables 9, 10 and 11 of the FSJ/DC 2025-2027 RRA and Tables 5, 6 and 7 of the TR 2025-2027 RRA.

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- shared service cost recoveries from PNG(NE) because of the net reductions in PNG-West OMA&G.
- Flow-through impacts on transfers to capital because of the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and the directives in the Decision, including disallowance of certain capital expenditures related to integrity activities.
- Reductions to depreciation resulting from the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and directives in the Decision.
- Flow-through impacts of the directives in the Decision on amortization.
- Flow-through impacts of the foregoing adjustments on income taxes, return on equity and interest expense.
- Reduction to Company use gas cost reflecting the adjustment identified in the course of the proceeding for the elimination of the BC Carbon Tax effective April 1, 2025.
- Flow-through impacts of the foregoing adjustments on margin.
- Flow-through impacts on the Rate Smoothing deferral account arising from the foregoing adjustments.
- TR:
  - Net reductions to OMG&A to reflect both adjustments and corrections identified in the course of the proceeding, and also the flow-through impacts that reduce shared service cost recoveries from PNG(NE) because of the net reductions in PNG-West OMA&G.
  - Flow-through impacts on transfers to capital because of the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and the directives in the Decision, including disallowance of certain capital expenditures related to integrity works.
  - Reductions to depreciation resulting from the reduction in Test Period capital expenditures that reflect both adjustments and corrections identified in the course of the proceeding and directives in the Decision.
  - Flow-through impacts of the directives in the Decision on amortization.
  - Flow-through impacts of the foregoing adjustments on income taxes, return on equity and interest expense.

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- Reduction to Company use gas cost reflecting the adjustment identified in the course of the proceeding for the elimination of the BC Carbon Tax effective April 1, 2025.
- Flow-through impacts of the foregoing adjustments on margin.
- Flow-through impacts on the Rate Smoothing deferral account arising from the foregoing adjustments.

The cost of service comparisons also illustrate the indicative average (of all customers) and the residential percentage rate change for each test year as per implementation of the Decisions, as described above, versus those applied for in the 2025-2027 RRAs. Customer bill impacts of these changes are addressed further below under Bill Impact Comparisons.

### **Allocation of Revenue Deficiency/Sufficiency**

As part of the rate setting process, PNG's RRA model allocates the forecast revenue deficiency or sufficiency to the various customer classes using normalized gross margins as the allocator. The proposed rate change for each customer class is determined by dividing the allocated revenue deficiency or sufficiency by the forecast marginable deliveries for that customer class. Further, PNG's RRA model typically allocates proposed rate increases for a customer class between the basic charge and delivery charge elements such that the elements change by the same percentage. In the case of proposed rate decreases, PNG recent practice is to apply the full amount of the decrease solely to the delivery charge element.

In support of the proposed adjustments to the interim basic and delivery charges, **Exhibit B** provides schedules for each division that show how the provisional Test Year 2026 revenue deficiency or sufficiency is allocated to each customer class and the resultant rate changes. The three columns on the far right of the schedules provide the distribution of the resultant rate change between the basic and delivery charges.

Also included in Exhibit B are schedules for each division that show how the provisional Test Year 2025 revenue deficiency or sufficiency is allocated to each customer class and the resultant rate changes. The provisional 2025 rate changes and resultant rates are relevant as they underly the changes sought to the 2026 basic and delivery charges.

For reference, the schedules presented retain the original header page numbers from Tab Schedules, Tab 6 of the 2025–2027 RRAs.

### **Proposed Rate Changes**

To illustrate the computation of the proposed rate changes, **Exhibit C** includes summaries of the 2025 and 2026 provisional/indicative rates that result from the allocation of the respective

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revenue deficiencies or sufficiencies as described in the previous section. The 2025 summaries illustrate the changes required to establish the 2025 basic and delivery charges following the implementation of Decisions, as described above.

The 2026 summaries illustrate the changes required to establish the 2026 basic and delivery charges following the implementation of the provision annual rate increases and build upon the 2025 summaries. In the 2026 summaries the basic and delivery charges for which changes are sought have been highlighted with yellow and bold.

In the 2026 summaries, PNG notes that:

- Column A figures align with those in the 2025 summaries under the “Proposed/ Indicative Rates January 1, 2025” column;
- Column B figures align with the allocation of the 2026 revenue deficiencies/ sufficiencies, as described in the previous section; and
- Column D figures represent the provisional/indicative rates for 2026 that result from implementation of the interim rate increases.

Further,

- Column F figures represent rates and rate elements that are presently in place, including those previously approved by the BCUC effective May 1, 2025, and January 1, 2026.
- Column G figures represent the changes to interim rates that are being sought, that being the difference between provisional/indicative rates for 2026 and the rates presently in place; and
- Column H represents the percentage rate increase of the rate changes being sought.

Once again, the schedules presented retain the original header page numbers from Tab Schedules, Tab 6 of the 2025–2027 RRAs for reference.

Also appended for reference as **Exhibit D** is a summary of PNG rate schedules to illustrate BCUC-approved rate changes that have been implemented in the period January 1, 2025, to the current date, as well as the changes proposed in this submission.

### **Other Regulatory Schedules**

Appended under **Exhibit E** are the following summary regulatory schedules extracted from PNG’s financial model that are typically included in the RRAs under Tab Schedules, including:

- Tab 1 - Utility Income & Return

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- Tab 2 - Utility Rate Base
- Tab 3 - Income Taxes
- Tab 4 - Common Equity
- Tab 5 - Return on Capital

PNG has provided copies of the noted regulatory schedules that were included in the 2025-2027 RRAs, as well as copies of the regulatory schedules that reflect the implementation of the provisional revenue requirements, as described above.

**Bill Impact Comparisons**

Included as **Exhibit F**, PNG has provided residential and small commercial customer bill comparison tables for all of PNG’s service areas that compare the annual bills based on the rates that result from implementing the proposed basic and delivery charges relative to rates presently in place. The bill comparisons illustrate the impacts of the proposed changes to the interim basic and delivery charges as addressed in this submission.

For further reference, PNG has compiled the following summary of bill impacts for each rate element for which it is requesting approval to revise in this submission.

**Average Annual Bill Impacts of Proposed Rate Changes**

Division / Element	Residential Impacts		Small Commercial Impacts	
	\$	%	\$	%
<b>PNG-West</b>				
Basic Charge	\$15.48	7.6%	\$36.12	7.6%
Delivery Charge	\$100.25	7.6%	\$415.43	7.6%
Overall Bill Impact	\$115.73	6.9%	\$451.55	6.7%
<b>Fort St. John (FSJ)</b>				
Basic Charge	\$9.12	8.8%	\$9.12	8.8%
Delivery Charge	\$60.40	8.7%	\$209.92	8.7%
Overall Bill Impact	\$69.52	6.7%	\$219.04	6.1%
<b>Dawson Creek (DC)</b>				
Basic Charge	\$9.12	8.8%	\$9.12	8.8%
Delivery Charge	\$57.55	9.1%	\$211.48	9.1%
Overall Bill Impact	\$66.67	7.0%	\$220.60	6.2%
<b>Tumbler Ridge (TR)</b>				
Basic Charge	nil	n/a	nil	n/a
Delivery Charge	(\$17.53)	(2.0%)	(\$76.13)	(1.8%)
Overall Bill Impact	(\$17.53)	(1.5%)	(\$76.13)	(1.4%)

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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PNG reiterates that approval of the foregoing changes to the basic charges and delivery charges is being sought on an interim and refundable or collectable basis pending the conclusion of the BCUC's review of the Reconsideration Applications and the determinations made in the respective proceedings to review those applications.

**Conclusion**

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PNG submits that revising the interim rates for 2026 at this time is reasonable, is generally consistent with the BCUC's 2025-2027 RRA Decisions, and in the public interest. Doing so avoids the unnecessary accumulation of deferral balances and provides a more accurate and timely reflection of the costs required to serve customers during the 2026 test year while the reconsideration process advances.

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit A – Cost of Service Comparisons – 2025-2027 Decisions vs 2025-2027 RRAs**

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**TEST YEAR 2025 - PROVISIONAL DECISION vs APPLICATION**  
**COST OF SERVICE COMPARISON**  
**(\$000)**

EXPENSES (\$000's)	Provisional Decision 2025	Application 2025	Difference Total	Subtotal
<b>Operating</b>				
Labour	9,485	9,580	(95)	
Other	7,156	7,257	(101)	
Shared Services Recovery from PNG(NE)	(2,280)	(2,305)	25	
Sub-total	<u>14,360</u>	<u>14,532</u>	<u>(172)</u>	
<b>Maintenance</b>				
Labour	288	288	0	
Other	583	583	0	
Sub-total	<u>871</u>	<u>871</u>	<u>0</u>	
<b>Administrative and General</b>				
Labour	4,326	4,326	(0)	
Total Company Benefits	2,865	2,865	0	
Other	8,107	8,323	(215)	
Shared Services Recovery from PNG(NE)	(3,160)	(3,169)	9	
Sub-total	<u>12,138</u>	<u>12,344</u>	<u>(206)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>27,370</b>	<b>27,748</b>	<b>(378)</b>	<b>(378)</b>
Transfers to Capital - Operating	(1,337)	(1,318)	(19)	
Transfers to Capital - Administrative & General	(1,017)	(1,067)	49	
<b>Property Taxes</b>	4,935	4,935	0	
<b>Depreciation</b>	10,716	10,716	0	
<b>Amortization</b>	13,435	7,654	5,782	
<b>Other Income</b>	(251)	(251)	0	5,812
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>53,850</b>	<b>48,416</b>	<b>5,434</b>	<b>5,434</b>
<b>Income Taxes</b>	1,894	537	1,357	
<b>Return on Common Equity</b>	20,286	20,300	(14)	
<b>Short Term Debt</b>	159	159	0	
<b>Long Term Debt</b>	9,612	9,586	26	1,369
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>85,802</b>	<b>78,998</b>	<b>6,803</b>	<b>6,803</b>
<b>Company Use Gas Cost</b>	528	745	(217)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>86,329</b>	<b>79,743</b>	<b>6,586</b>	
<b>2024 to 2025 Cost of Service Increase / (Decrease)</b>	<b>26,453</b>	<b>19,649</b>	<b>6,804</b>	
<b>2024 to 2025 Margin (Increase) / Decrease</b>	<b>5,607</b>	<b>5,019</b>	<b>589</b>	
<b>2024 Integrity Deferral Increase / (Decrease)</b>	<b>2,000</b>	<b>2,000</b>	<b>0</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(25,085)</b>	<b>(12,036)</b>	<b>(13,049)</b>	
<b>2025 Revenue Deficiency / (Sufficiency)</b>	<b>8,975</b>	<b>14,632</b>	<b>(5,657)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>17.17%</b>	<b>27.57%</b>	<b>-10.40%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>17.26%</b>	<b>27.78%</b>	<b>-10.51%</b>	

Pacific Northern Gas Ltd.  
(PNG-West Division)

TEST YEAR 2026 - PROVISIONAL DECISION vs APPLICATION  
COST OF SERVICE COMPARISON  
(\$000)

EXPENSES (\$000's)	Provisional		Difference	
	Decision 2026	Application 2026	Total	Subtotal
<b>Operating</b>				
Labour	9,952	9,952	0	
Other	7,464	7,619	(154)	
Shared Services Recovery from PNG(NE)	(2,383)	(2,422)	39	
Sub-total	<u>15,033</u>	<u>15,148</u>	<u>(115)</u>	
<b>Maintenance</b>				
Labour	312	312	0	
Other	422	601	(179)	
Sub-total	<u>734</u>	<u>913</u>	<u>(179)</u>	
<b>Administrative and General</b>				
Labour	4,456	4,456	(0)	
Total Company Benefits	3,011	3,011	0	
Other	8,180	8,482	(302)	
Shared Services Recovery from PNG(NE)	(3,214)	(3,224)	10	
Sub-total	<u>12,433</u>	<u>12,725</u>	<u>(293)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>28,200</b>	<b>28,786</b>	<b>(587)</b>	<b>(587)</b>
Transfers to Capital - Operating	(1,529)	(1,505)	(24)	
Transfers to Capital - Administrative & General	(1,155)	(1,145)	(10)	
<b>Property Taxes</b>	5,022	5,022	0	
<b>Depreciation</b>	12,183	12,287	(104)	
<b>Amortization</b>	3,425	3,425	(0)	
<b>Other Income</b>	(251)	(251)	0	(138)
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>45,894</b>	<b>46,619</b>	<b>(725)</b>	<b>(725)</b>
<b>Income Taxes</b>	5,672	3,257	2,416	
<b>Return on Common Equity</b>	21,699	21,989	(290)	
<b>Short Term Debt</b>	156	159	(3)	
<b>Long Term Debt</b>	9,554	9,608	(54)	2,069
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>82,975</b>	<b>81,632</b>	<b>1,343</b>	<b>1,343</b>
<b>Company Use Gas Cost</b>	480	828	(348)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>83,455</b>	<b>82,459</b>	<b>995</b>	
<b>2025 to 2026 Cost of Service Increase / (Decrease)</b>	<b>(2,827)</b>	<b>2,633</b>	<b>(5,460)</b>	
<b>2025 to 2026 Margin (Increase) / Decrease</b>	<b>(374)</b>	<b>(1,521)</b>	<b>1,147</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>25,085</b>	<b>12,036</b>	<b>13,049</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(11,311)</b>	<b>5,985</b>	<b>(17,296)</b>	
<b>2026 Revenue Deficiency / (Sufficiency)</b>	<b>10,573</b>	<b>19,134</b>	<b>(8,561)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>17.17%</b>	<b>27.61%</b>	<b>-10.43%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>17.24%</b>	<b>27.78%</b>	<b>-10.54%</b>	

Pacific Northern Gas Ltd.  
(PNG-West Division)

TEST YEAR 2027 - PROVISIONAL DECISION vs APPLICATION  
COST OF SERVICE COMPARISON  
(\$000)

EXPENSES (\$000's)	Provisional		Difference	
	Decision 2027	Application 2027	Total	Subtotal
<b>Operating</b>				
Labour	10,630	10,630	0	
Other	7,758	7,815	(57)	
Shared Services Recovery from PNG(NE)	(2,629)	(2,629)	0	
Sub-total	<u>15,760</u>	<u>15,816</u>	<u>(57)</u>	
<b>Maintenance</b>				
Labour	322	322	0	
Other	619	619	0	
Sub-total	<u>941</u>	<u>941</u>	<u>0</u>	
<b>Administrative and General</b>				
Labour	4,653	4,653	0	
Total Company Benefits	3,290	3,290	(0)	
Other	6,687	8,820	(2,133)	
Shared Services Recovery from PNG(NE)	(3,313)	(3,321)	8	
Sub-total	<u>11,317</u>	<u>13,442</u>	<u>(2,125)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>28,017</b>	<b>30,199</b>	<b>(2,182)</b>	<b>(2,182)</b>
Transfers to Capital - Operating	(1,270)	(1,346)	75	
Transfers to Capital - Administrative & General	(722)	(1,083)	361	
<b>Property Taxes</b>	5,111	5,111	0	
<b>Depreciation</b>	13,182	13,920	(738)	
<b>Amortization</b>	(3,693)	3,097	(6,789)	
<b>Other Income</b>	(251)	(251)	0	(7,091)
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>40,374</b>	<b>49,647</b>	<b>(9,273)</b>	<b>(9,273)</b>
<b>Income Taxes</b>	6,468	4,168	2,299	
<b>Return on Common Equity</b>	22,617	23,900	(1,283)	
<b>Short Term Debt</b>	164	175	(10)	
<b>Long Term Debt</b>	9,755	10,083	(328)	678
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>79,378</b>	<b>87,973</b>	<b>(8,595)</b>	<b>(8,595)</b>
<b>Company Use Gas Cost</b>	540	899	(359)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>79,918</b>	<b>88,873</b>	<b>(8,954)</b>	
<b>2026 to 2027 Cost of Service Increase / (Decrease)</b>	<b>(3,597)</b>	<b>6,342</b>	<b>(9,938)</b>	
<b>2026 to 2027 Margin (Increase) / Decrease</b>	<b>(2,417)</b>	<b>(2,677)</b>	<b>260</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>11,311</b>	<b>(5,985)</b>	<b>17,296</b>	
<b>2027 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>7,516</b>	<b>6,859</b>	<b>657</b>	
<b>2027 Revenue Deficiency / (Sufficiency)</b>	<b>12,813</b>	<b>4,539</b>	<b>16,549</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>17.17%</b>	<b>4.98%</b>	<b>12.19%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>17.23%</b>	<b>5.00%</b>	<b>12.23%</b>	

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John / Dawson Creek Division)**

**TEST YEAR 2025 - PROVISIONAL DECISION vs APPLICATION**  
**COST OF SERVICE COMPARISON**  
**(\$000)**

EXPENSES (\$000's)	Provisional Decision 2025	Application 2025	Difference Total	Subtotal
<b>Operating</b>				
Labour	2,992	2,992	0	
Other	4,642	4,678	(36)	
Sub-total	<u>7,634</u>	<u>7,670</u>	<u>(36)</u>	
<b>Maintenance</b>				
Labour	149	149	0	
Other	439	439	0	
Sub-total	<u>588</u>	<u>588</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	561	561	0	
Other	3,512	3,575	(63)	
Sub-total	<u>4,073</u>	<u>4,136</u>	<u>(63)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>12,295</b>	<b>12,394</b>	<b>(99)</b>	<b>(99)</b>
Transfers to Capital Operating	(679)	(717)	38	
Transfers to Capital - Administrative & General	(348)	(363)	15	
<b>Property Taxes</b>	1,642	1,642	0	
<b>Depreciation</b>	2,897	2,897	0	
<b>Amortization</b>	2,463	2,466	(3)	
<b>Other Income</b>	(200)	(200)	0	50
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>18,071</b>	<b>18,120</b>	<b>(49)</b>	<b>(49)</b>
<b>Income Taxes</b>	1,336	1,318	17	
<b>Return on Common Equity</b>	4,409	4,435	(27)	
<b>Short Term Debt</b>	6	20	(14)	
<b>Long Term Debt</b>	2,327	2,326	0	(23)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>26,148</b>	<b>26,220</b>	<b>(72)</b>	<b>(72)</b>
<b>Company Use Gas Cost</b>	165	193	(28)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>26,313</b>	<b>26,412</b>	<b>(100)</b>	
<b>2024 to 2025 Cost of Service Increase / (Decrease)</b>	<b>2,203</b>	<b>2,275</b>	<b>(72)</b>	
<b>2024 to 2025 Margin (Increase) / Decrease</b>	<b>1,491</b>	<b>1,370</b>	<b>121</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(1,730)</b>	<b>(1,670)</b>	<b>(60)</b>	
<b>2025 Revenue Deficiency / (Sufficiency)</b>	<b>1,963</b>	<b>1,974</b>	<b>(11)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>8.68%</b>	<b>8.67%</b>	<b>0.01%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>8.81%</b>	<b>8.81%</b>	<b>0.00%</b>	

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John / Dawson Creek Division)

**TEST YEAR 2026 - PROVISIONAL DECISION vs APPLICATION**  
**COST OF SERVICE COMPARISON**  
((\$000))

EXPENSES (\$000's)	Provisional Decision 2026	Application 2026	Difference Total	Subtotal
<b>Operating</b>				
Labour	3,159	3,159	0	
Other	4,696	4,749	(53)	
Sub-total	<u>7,855</u>	<u>7,908</u>	<u>(53)</u>	
<b>Maintenance</b>				
Labour	160	160	0	
Other	458	458	0	
Sub-total	<u>618</u>	<u>618</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	606	606	0	
Other	3,502	3,538	(36)	
Sub-total	<u>4,107</u>	<u>4,144</u>	<u>(36)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>12,580</b>	<b>12,669</b>	<b>(89)</b>	<b>(89)</b>
Transfers to Capital - Operating	(622)	(642)	20	
Transfers to Capital - Administrative & General	(318)	(333)	15	
<b>Property Taxes</b>	1,670	1,670	0	
<b>Depreciation</b>	3,188	3,206	(18)	
<b>Amortization</b>	1,203	1,206	(3)	
<b>Other Income</b>	(200)	(200)	0	13
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>17,502</b>	<b>17,577</b>	<b>(75)</b>	<b>(75)</b>
<b>Income Taxes</b>	1,474	1,456	18	
<b>Return on Common Equity</b>	4,685	4,775	(91)	
<b>Short Term Debt</b>	22	22	(0)	
<b>Long Term Debt</b>	2,420	2,456	(35)	(108)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>26,103</b>	<b>26,286</b>	<b>(184)</b>	<b>(184)</b>
<b>Company Use Gas Cost</b>	197	245	(48)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>26,300</b>	<b>26,532</b>	<b>(232)</b>	
<b>2025 to 2026 Cost of Service Increase / (Decrease)</b>	<b>(45)</b>	<b>67</b>	<b>(112)</b>	
<b>2025 to 2026 Margin (Increase) / Decrease</b>	<b>218</b>	<b>182</b>	<b>35</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>1,730</b>	<b>1,670</b>	<b>60</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>215</b>	<b>233</b>	<b>(18)</b>	
<b>2026 Revenue Deficiency / (Sufficiency)</b>	<b>2,118</b>	<b>2,152</b>	<b>(34)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>8.63%</b>	<b>8.62%</b>	<b>0.01%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>8.81%</b>	<b>8.81%</b>	<b>0.00%</b>	

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John / Dawson Creek Division)

**TEST YEAR 2027 - PROVISIONAL DECISION vs APPLICATION**  
**COST OF SERVICE COMPARISON**  
((\$000))

EXPENSES (\$000's)	Provisional Decision 2027	Application 2027	Difference Total	Subtotal
<b>Operating</b>				
Labour	3,263	3,263	0	
Other	4,972	4,989	(17)	
Sub-total	<u>8,235</u>	<u>8,252</u>	<u>(17)</u>	
<b>Maintenance</b>				
Labour	165	165	0	
Other	471	471	0	
Sub-total	<u>636</u>	<u>636</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	650	650	0	
Other	3,624	3,662	(38)	
Sub-total	<u>4,274</u>	<u>4,312</u>	<u>(38)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>13,145</b>	<b>13,201</b>	<b>(56)</b>	<b>(56)</b>
Transfers to Capital - Operating	(924)	(895)	(29)	
Transfers to Capital - Administrative & General	(452)	(451)	(1)	
<b>Property Taxes</b>	1,699	1,699	0	
<b>Depreciation</b>	3,380	3,416	(36)	
<b>Amortization</b>	1,193	1,198	(5)	
<b>Other Income</b>	(200)	(200)	0	(71)
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>17,843</b>	<b>17,969</b>	<b>(127)</b>	<b>(127)</b>
<b>Income Taxes</b>	1,534	1,398	136	
<b>Return on Common Equity</b>	4,852	5,135	(283)	
<b>Short Term Debt</b>	23	25	(2)	
<b>Long Term Debt</b>	2,538	2,641	(104)	(253)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>26,789</b>	<b>27,168</b>	<b>(380)</b>	<b>(380)</b>
<b>Company Use Gas Cost</b>	207	254	(47)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>26,996</b>	<b>27,422</b>	<b>(427)</b>	
<b>2026 to 2027 Cost of Service Increase / (Decrease)</b>	<b>686</b>	<b>882</b>	<b>(196)</b>	
<b>2026 to 2027 Margin (Increase) / Decrease</b>	<b>179</b>	<b>108</b>	<b>71</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(215)</b>	<b>(233)</b>	<b>18</b>	
<b>2027 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>1,659</b>	<b>1,575</b>	<b>84</b>	
<b>2027 Revenue Deficiency / (Sufficiency)</b>	<b>2,307</b>	<b>2,332</b>	<b>(24)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>8.64%</b>	<b>8.64%</b>	<b>0.01%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>8.81%</b>	<b>8.81%</b>	<b>0.00%</b>	

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

TEST YEAR 2025 - PROVISIONAL DECISION vs APPLICATION  
COST OF SERVICE COMPARISON  
(\$000)

EXPENSES (\$000's)	Provisional Decision 2025	Application 2025	Difference Total	Subtotal
<b>Operating</b>				
Labour	339	339	0	
Other	455	458	(2)	
Sub-total	<u>795</u>	<u>797</u>	<u>(2)</u>	
<b>Maintenance</b>				
Labour	48	48	0	
Other	132	132	0	
Sub-total	<u>180</u>	<u>180</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	34	34	0	
Other	270	276	(6)	
Sub-total	<u>304</u>	<u>310</u>	<u>(6)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>1,278</b>	<b>1,287</b>	<b>(8)</b>	<b>(8)</b>
Transfers to Capital Operating	(114)	(119)	5	
Transfers to Capital - Administrative & General	(52)	(54)	2	
<b>Property Taxes</b>	133	133	0	
<b>Depreciation</b>	299	299	0	
<b>Amortization</b>	50	50	0	
<b>Other Income</b>	(29)	(29)	0	6
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>1,565</b>	<b>1,567</b>	<b>(2)</b>	<b>(2)</b>
<b>Income Taxes</b>	194	192	2	
<b>Return on Common Equity</b>	432	438	(6)	
<b>Short Term Debt</b>	3	3	(0)	
<b>Long Term Debt</b>	184	186	(2)	(6)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>2,378</b>	<b>2,386</b>	<b>(8)</b>	<b>(8)</b>
<b>Company Use Gas Cost</b>	58	104	(46)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>2,436</b>	<b>2,490</b>	<b>(54)</b>	
<b>2024 to 2025 Cost of Service Increase / (Decrease)</b>	<b>(123)</b>	<b>(115)</b>	<b>(8)</b>	
<b>2024 to 2025 Margin (Increase) / Decrease</b>	<b>(745)</b>	<b>(745)</b>	<b>0</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>809</b>	<b>800</b>	<b>9</b>	
<b>2025 Revenue Deficiency / (Sufficiency)</b>	<b>(59)</b>	<b>(60)</b>	<b>1</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>-1.77%</b>	<b>-1.78%</b>	<b>0.00%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>-2.00%</b>	<b>-2.00%</b>	<b>0.00%</b>	

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

TEST YEAR 2026 - PROVISIONAL DECISION vs APPLICATION  
COST OF SERVICE COMPARISON  
(\$000)

EXPENSES (\$000's)	Provisional Decision 2026	Application 2026	Difference Total	Subtotal
<b>Operating</b>				
Labour	417	417	0	
Other	455	459	(4)	
Sub-total	<u>872</u>	<u>876</u>	<u>(4)</u>	
<b>Maintenance</b>				
Labour	50	50	0	
Other	136	136	0	
Sub-total	<u>187</u>	<u>187</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	37	37	0	
Other	273	278	(5)	
Sub-total	<u>310</u>	<u>315</u>	<u>(5)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>1,369</b>	<b>1,378</b>	<b>(9)</b>	<b>(9)</b>
Transfers to Capital - Operating	(87)	(91)	4	
Transfers to Capital - Administrative & General	(33)	(40)	7	
<b>Property Taxes</b>	135	135	0	
<b>Depreciation</b>	338	341	(3)	
<b>Amortization</b>	534	535	(1)	
<b>Other Income</b>	(29)	(29)	0	6
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>2,227</b>	<b>2,230</b>	<b>(3)</b>	<b>(3)</b>
<b>Income Taxes</b>	217	217	1	
<b>Return on Common Equity</b>	468	487	(19)	
<b>Short Term Debt</b>	3	3	(0)	
<b>Long Term Debt</b>	184	190	(6)	(24)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>3,099</b>	<b>3,126</b>	<b>(27)</b>	<b>(27)</b>
<b>Company Use Gas Cost</b>	3	7	(3)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>3,102</b>	<b>3,132</b>	<b>(30)</b>	
<b>2025 to 2026 Cost of Service Increase / (Decrease)</b>	<b>721</b>	<b>739</b>	<b>(18)</b>	
<b>2025 to 2026 Margin (Increase) / Decrease</b>	<b>(2)</b>	<b>(0)</b>	<b>(2)</b>	
<b>2025 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(809)</b>	<b>(800)</b>	<b>(9)</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>34</b>	<b>5</b>	<b>29</b>	
<b>2026 Revenue Deficiency / (Sufficiency)</b>	<b>(56)</b>	<b>(56)</b>	<b>0</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>-1.76%</b>	<b>-1.76%</b>	<b>0.00%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>-2.00%</b>	<b>-2.00%</b>	<b>0.00%</b>	

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

TEST YEAR 2027 - PROVISIONAL DECISION vs APPLICATION  
COST OF SERVICE COMPARISON  
(\$000)

EXPENSES (\$000's)	Provisional	Application	Difference	
	Decision 2027	2027	Total	Subtotal
<b>Operating</b>				
Labour	430	430	0	
Other	478	479	(1)	
Sub-total	<u>908</u>	<u>909</u>	<u>(1)</u>	
<b>Maintenance</b>				
Labour	52	52	0	
Other	140	140	0	
Sub-total	<u>192</u>	<u>192</u>	<u>0</u>	
<b>Administrative and General</b>				
Total Company Benefits	42	42	0	
Other	281	286	(5)	
Sub-total	<u>324</u>	<u>329</u>	<u>(5)</u>	
<b>Total (O, M, A &amp; G) Excluding Company Use Gas Cost</b>	<b>1,424</b>	<b>1,430</b>	<b>(6)</b>	<b>(6)</b>
Transfers to Capital - Operating	(112)	(84)	(28)	
Transfers to Capital - Administrative & General	(44)	(37)	(7)	
<b>Property Taxes</b>	137	137	0	
<b>Depreciation</b>	369	376	(7)	
<b>Amortization</b>	249	250	(1)	
<b>Other Income</b>	(29)	(29)	0	(43)
<b>Total Expenses Excluding Company Use Gas Cost</b>	<b>1,994</b>	<b>2,043</b>	<b>(49)</b>	<b>(49)</b>
<b>Income Taxes</b>	223	216	7	
<b>Return on Common Equity</b>	482	513	(31)	
<b>Short Term Debt</b>	3	3	(0)	
<b>Long Term Debt</b>	194	202	(9)	(33)
<b>Total Cost of Service Excluding Company Use Gas Cost</b>	<b>2,896</b>	<b>2,978</b>	<b>(82)</b>	<b>(82)</b>
<b>Company Use Gas Cost</b>	3	7	(3)	
<b>Total Cost of Service Including Company Use Gas Cost</b>	<b>2,899</b>	<b>2,985</b>	<b>(86)</b>	
<b>2026 to 2027 Cost of Service Increase / (Decrease)</b>	<b>(203)</b>	<b>(148)</b>	<b>(55)</b>	
<b>2026 to 2027 Margin (Increase) / Decrease</b>	<b>(2)</b>	<b>(2)</b>	<b>(0)</b>	
<b>2026 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>(34)</b>	<b>(5)</b>	<b>(29)</b>	
<b>2027 Rate Smoothing Deferral Increase / (Decrease)</b>	<b>184</b>	<b>99</b>	<b>84</b>	
<b>2027 Revenue Deficiency / (Sufficiency)</b>	<b>(55)</b>	<b>(55)</b>	<b>(0)</b>	
<b>Average Rate Increase / (Decrease)</b>	<b>-1.76%</b>	<b>-1.76%</b>	<b>0.00%</b>	
<b>Residential Rate Increase / (Decrease)</b>	<b>-2.00%</b>	<b>-2.00%</b>	<b>0.00%</b>	

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit B – Allocation of Revenue Deficiency/Sufficiency**

Pacific Northern Gas Ltd.  
 (PNG-West Division)

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2025**

Customer Classification	2025	2025	2025	2025	Allocation of Revenue Deficiency (\$)	Proposed Rate Changes for Rev. Def. (\$/GJ)	Allocation of Proposed Change		
	Test Year Physical Deliveries (GJ)	Test Year Marginable Deliveries (GJ)	Gross Margin (\$)	Normalized Gross Margin (\$)			Delivery Charge (\$/GJ)	Basic Charge (\$/GJ)	Basic Charge (\$/Month)
<b>Residential (RS 1)</b>	1,186,456	1,186,456	22,126,416	22,126,416	3,799,442	3.202	2.782	0.420	2.30
<b>Granisle (RS 1 - Propane)</b>	5,877	5,877	76,796	76,796	13,187	2.244	1.609	0.635	2.30
<b>Commercial</b>									
Small Commercial Firm (RS 2)	798,181	798,181	11,834,075	11,834,075	2,032,091	2.527	2.341	0.186	5.37
Large Commercial Firm (RS 3)	294,985	294,985	3,259,248	3,259,248	559,662	1.903	1.879	0.024	32.36
Small Comm Transport (RS 22)	107,380	107,380	1,494,332	1,494,332	256,600	2.527	2.341	0.186	5.37
Large Comm Transport (RS 33)	96,300	96,300	1,076,366	1,076,366	184,828	1.903	1.879	0.024	32.36
Commercial Interruptible (RS 5)	56,950	56,950	392,624	392,624	67,420	1.184	1.155	0.029	27.16
<b>Total Commercial</b>	<b>1,353,796</b>	<b>1,353,796</b>	<b>18,056,645</b>	<b>18,056,645</b>					
<b>Seasonal Off-Peak (RS 6)</b>	16,700	16,700	170,438	170,438	29,267	1.753	1.709	0.044	26.97
<b>NGV (RS 7)</b>	0	0	0	0	0	n.a.	0.000	0.000	0.00
<b>Small Industrial</b>									
Sales - Firm (RS 4)	190,247	198,897	1,034,976	1,034,976	177,721	0.8725	0.8506	0.0220	89.85
Sales - IT (RS 4)	18,252	18,252	80,698	80,698	13,857	0.7592	0.7592	0.0000	0.00
Transport - Firm (RS 40)	292,000	292,000	1,459,433	1,459,433	250,607	0.8725	0.8506	0.0220	89.85
Interruptible Transport	939,367	939,367	4,153,224	4,153,223	713,172	0.7592	0.7592	0.0000	0.00
<b>Total Small Industrial</b>	<b>1,439,866</b>	<b>1,448,516</b>	<b>6,728,330</b>	<b>6,728,330</b>					
<b>Large Volume Industrial (RS 80)</b>									
Firm Transport	0	0	0	0	0	n.a.	0.0000	0.0000	0.00
Interruptible Transport	0	0	0	0	0	n.a.	0.0000	0.0000	0.00
Sub-total	0	0	0	0	0				
<b>Rio Tinto Alcan</b>									
Firm Transport	1,176,000	1,207,492	4,877,181	4,877,181	837,486	0.6936	0.6936	0.0000	0.00
Interruptible Transport	0	0	0	0	0	0.7592	0.7592	0.0000	0.00
Sub-total	1,176,000	1,207,492	4,877,181	4,877,181					
<b>B.C. Hydro - Interruptible Transport</b>	36,000	36,000	233,123	233,123	40,031	1.1120	0.7592	0.3528	1058.28
<b>Total Large Industrial</b>	<b>1,212,000</b>	<b>1,243,492</b>	<b>5,110,304</b>	<b>5,110,304</b>					
<b>TOTAL</b>	<b>5,214,695</b>	<b>5,254,837</b>	<b>52,268,930</b>	<b>52,268,930</b>	<b>8,975,370</b>				
<b>Summary</b>									
Sales	2,567,648	2,576,298	38,975,271	38,975,271	6,692,647				
Transportation	2,647,047	2,678,539	13,293,659	13,293,659	2,282,723				
<b>Total</b>	<b>5,214,695</b>	<b>5,254,837</b>	<b>52,268,930</b>	<b>52,268,930</b>	<b>8,975,370</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2025**

Customer Classification	2025	2025	2025	Allocation of	Proposed Rate Changes for Rev. Def. (\$/GJ)	Allocation of Proposed Change		
	Test Year	Test Year	Gross	Revenue		Delivery	Basic	Basic
	Gas Deliveries (GJ)	Marginable Deliveries (GJ)	Margin (\$)	Deficiency (\$)		Charge (\$/GJ)	Charge (\$/GJ)	Charge (\$/Month)
<b>Residential (RS 1)</b>	1,721,689	1,721,689	13,041,447	1,142,565	0.664	0.577	0.087	0.70
<b>Commercial</b>								
Small Commercial (RS 2)	1,202,537	1,202,537	6,071,670	531,941	0.442	0.424	0.018	0.70
Large Commercial Firm (RS 3)	310,425	310,425	1,134,210	99,368	0.320	0.306	0.015	15.10
Commercial Transportation (RS 23)	79,050	79,050	374,476	32,808	0.415	0.352	0.063	12.54
<b>Small Industrial Sales (RS 4)</b>	409,300	409,300	1,025,122	89,811	0.219	0.207	0.012	41.54
<b>Industrial Transport</b>								
RS 6	177,725	177,725	487,197	42,684	0.2402	0.2262	0.0140	41.47
RS 7	356,133	980,025	206,502	0	0.0000	0.0000	0.0000	41.54
RS 10	159,000	159,000	278,328	24,384	0.1534	0.1056	0.0478	316.48
<b>Total</b>	<b>4,415,859</b>	<b>5,039,751</b>	<b>22,618,952</b>	<b>1,963,562</b>				
<b>Summary</b>								
Sales	3,643,951	3,643,951	21,272,449	1,863,686				
Transportation	771,908	1,395,800	1,346,503	99,876				
<b>Total</b>	<b>4,415,859</b>	<b>5,039,751</b>	<b>22,618,952</b>	<b>1,963,562</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2025**

Customer Classification	2025	2025	2025	Allocation of	Proposed Rate	Allocation of Proposed Change		
	Test Year	Test Year	Gross	Revenue		Delivery	Basic	Basic
	Gas Deliveries	Marginable Deliveries	Margin	Deficiency	Rev. Def.	Charge	Charge	Charge
	(GJ)	(GJ)	(\$)	(\$)	(\$/GJ)	(\$/GJ)	(\$/GJ)	(\$/Month)
Residential Sales (RS 1)	79,945	79,945	1,181,435	(20,954)	(0.262)	(0.262)	0.000	0.00
Small Commercial Sales (RS 2)	41,650	41,650	445,302	(7,898)	(0.190)	(0.190)	0.000	0.00
Large Commercial Sales (RS 3)	110,052	110,052	945,697	(16,773)	(0.152)	(0.152)	0.000	0.00
<b>Total Sales</b>	<b>231,647</b>	<b>231,647</b>	<b>2,572,433</b>	<b>(45,624)</b>				
Industrial Transport (CNRL)	720,000	720,000	731,559	(12,975)	(0.018)	(0.018)	0.000	0.00
<b>TOTAL</b>	<b>951,647</b>	<b>951,647</b>	<b>3,303,993</b>	<b>(58,599)</b>				
<b>Summary</b>								
Sales	231,647	231,647	2,572,433	(45,624)				
Transportation	720,000	720,000	731,559	(12,975)				
<b>Total</b>	<b>951,647</b>	<b>951,647</b>	<b>3,303,993</b>	<b>(58,599)</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2026**

Customer Classification	2026	2026	2026	2026	Allocation of Revenue Deficiency (\$)	Proposed Rate Changes for Rev. Def. (\$/GJ)	Allocation of Proposed Change		
	Test Year Physical Deliveries (GJ)	Test Year Marginable Deliveries (GJ)	Gross Margin (\$)	Normalized Gross Margin (\$)			Delivery Charge (\$/GJ)	Basic Charge (\$/GJ)	Basic Charge (\$/Month)
<b>Residential (RS 1)</b>	1,161,228	1,161,228	25,440,290	25,440,290	4,368,488	3.762	3.258	0.504	2.70
<b>Granisle (RS 1 - Propane)</b>	5,828	5,828	89,557	89,557	15,378	2.639	1.884	0.755	2.70
<b>Commercial</b>									
Small Commercial Firm (RS 2)	806,506	806,506	13,994,238	13,994,238	2,403,025	2.958	2.741	0.217	6.29
Large Commercial Firm (RS 3)	219,725	219,725	2,853,429	2,853,429	489,978	2.233	2.199	0.035	37.86
Small Comm Transport (RS 22)	107,335	107,335	1,748,793	1,748,793	300,295	2.958	2.741	0.217	6.29
Large Comm Transport (RS 33)	96,300	96,300	1,256,479	1,256,479	215,757	2.233	2.199	0.035	37.86
Commercial Interruptible (RS 5)	56,950	56,950	459,347	459,347	78,877	1.385	1.352	0.033	31.77
<b>Total Commercial</b>	<b>1,286,816</b>	<b>1,286,816</b>	<b>20,312,287</b>	<b>20,312,287</b>					
<b>Seasonal Off-Peak (RS 6)</b>	16,700	16,700	199,490	199,490	34,256	2.051	2.000	0.051	31.57
<b>NGV (RS 7)</b>	0	0	0	0	0	n.a.	0.000	0.000	0.00
<b>Small Industrial</b>									
Sales - Firm (RS 4)	250,886	458,843	2,858,217	2,858,217	490,800	1.0440	1.0259	0.0180	108.36
Sales - IT (RS 4)	29,346	29,346	151,675	151,675	26,045	0.8875	0.8875	0.0000	0.00
Transport - Firm (RS 40)	292,000	292,000	1,706,578	1,706,578	293,046	1.0440	1.0259	0.0180	108.36
Interruptible Transport	936,364	936,364	4,839,598	4,839,598	831,033	0.8875	0.8875	0.0000	0.00
<b>Total Small Industrial</b>	<b>1,508,596</b>	<b>1,716,553</b>	<b>9,556,068</b>	<b>9,556,068</b>					
<b>Large Volume Industrial (RS 80)</b>									
Firm Transport	0	0	0	0	0	n.a.	0.0000	0.0000	0.00
Interruptible Transport	0	0	0	0	0	n.a.	0.0000	0.0000	0.00
Sub-total	0	0	0	0					
<b>Rio Tinto Alcan</b>									
Firm Transport	1,176,000	1,207,492	5,700,207	5,700,207	978,813	0.8106	0.8106	0.0000	0.00
Interruptible Transport	0	0	0	0	0	0.8875	0.8875	0.0000	0.00
Sub-total	1,176,000	1,207,492	5,700,207	5,700,207					
<b>B.C. Hydro - Interruptible Transport</b>	36,000	36,000	272,725	272,725	46,831	1.3009	0.8875	0.4134	1254.58
<b>Total Large Industrial</b>	<b>1,212,000</b>	<b>1,243,492</b>	<b>5,972,932</b>	<b>5,972,932</b>					
<b>TOTAL</b>	<b>5,191,168</b>	<b>5,430,617</b>	<b>61,570,624</b>	<b>61,570,624</b>	<b>10,572,620</b>				
<b>Summary</b>									
Sales	2,547,169	2,755,126	46,046,243	46,046,243	7,906,846				
Transportation	2,643,999	2,675,491	15,524,381	15,524,381	2,665,774				
<b>Total</b>	<b>5,191,168</b>	<b>5,430,617</b>	<b>61,570,624</b>	<b>61,570,624</b>	<b>10,572,620</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2026**

Customer Classification	2026	2026	2026	Allocation of	Proposed Rate	Allocation of Proposed Change		
	Test Year	Test Year	Gross	Revenue		Delivery	Basic	Basic
	Gas Deliveries	Marginable Deliveries	Margin	Deficiency	Changes for	Charge	Charge	Charge
	(GJ)	(GJ)	(\$)	(\$)	Rev. Def.	(\$/GJ)	(\$/GJ)	(\$/Month)
<b>Residential (RS 1)</b>	1,693,475	1,693,475	14,002,144	1,226,141	0.7240	0.627	0.097	0.76
<b>Commercial</b>								
Small Commercial (RS 2)	1,201,793	1,201,793	6,610,238	578,846	0.482	0.462	0.020	0.76
Large Commercial Firm (RS 3)	302,350	302,350	1,203,448	105,384	0.349	0.332	0.016	16.45
Commercial Transportation (RS 23)	79,050	79,050	407,911	35,720	0.452	0.383	0.068	13.65
<b>Small Industrial Sales (RS 4)</b>	409,300	409,300	1,118,108	97,911	0.239	0.226	0.013	45.29
<b>Industrial Transport</b>								
RS 6	181,930	181,930	543,159	47,563	0.2614	0.2465	0.0149	45.20
RS 7	357,109	980,025	207,000	0	0.0000	(0.0006)	0.0006	45.29
RS 10	160,000	160,000	305,318	26,736	0.1671	0.1153	0.0518	345.50
<b>Total</b>	<b>4,385,007</b>	<b>5,007,923</b>	<b>24,397,327</b>	<b>2,118,300</b>				
<b>Summary</b>								
Sales	3,606,918	3,606,918	22,933,939	2,008,281				
Transportation	778,089	1,401,005	1,463,388	110,019				
<b>Total</b>	<b>4,385,007</b>	<b>5,007,923</b>	<b>24,397,327</b>	<b>2,118,300</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**SUMMARY OF PROPOSED GAS DELIVERY CHARGE AND BASIC CHARGE RATE CHANGES**  
**EFFECTIVE JANUARY 1, 2026**

Customer Classification	2026	2026	2026	Allocation of Revenue Deficiency (\$)	Proposed Rate Changes for Rev. Def. (\$/GJ)	Allocation of Proposed Change		
	Test Year Gas Deliveries (GJ)	Test Year Marginable Deliveries (GJ)	Gross Margin (\$)			Delivery Charge (\$/GJ)	Basic Charge (\$/GJ)	Basic Charge (\$/Month)
Residential Sales (RS 1)	79,193	79,193	1,132,380	(19,968)	(0.252)	(0.252)	0.000	0.00
Small Commercial Sales (RS 2)	42,769	42,769	438,726	(7,736)	(0.181)	(0.181)	0.000	0.00
Large Commercial Sales (RS 3)	110,050	110,050	902,982	(15,923)	(0.145)	(0.145)	0.000	0.00
<b>Total Sales</b>	<b>232,012</b>	<b>232,012</b>	<b>2,474,087</b>	<b>(43,627)</b>				
Industrial Transport (CNRL)	720,000	720,000	718,599	(12,671)	(0.018)	(0.018)	0.000	0.00
<b>TOTAL</b>	<b>952,012</b>	<b>952,012</b>	<b>3,192,686</b>	<b>(56,298)</b>				
<b>Summary</b>								
Sales	232,012	232,012	2,474,087	(43,627)				
Transportation	720,000	720,000	718,599	(12,671)				
<b>Total</b>	<b>952,012</b>	<b>952,012</b>	<b>3,192,686</b>	<b>(56,298)</b>				

Note: Each customer class share of the revenue deficiency is allocated based on the proportion of each customer class normalized gross margin to total normalized gross margin times the revenue deficiency. The allocated revenue deficiency divided by forecast deliveries equals the proposed rate change.

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit C – Illustrative Summary of Provisional/Indicative Rates and Rate Changes**

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b>Residential (RS 1)</b>					
Monthly Basic Charge	\$13.34	\$2.30		\$15.64	\$2.30
<b>Natural Gas</b>					
Delivery Charge	16.116	2.782		18.898	2.782
Company Use	0.128		(0.028)	0.100	(0.028)
GCV A Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	0.165		1.051	1.216	1.051
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	16.341	2.782	1.050	20.173	3.832
Gas Supply Demand	0.402		0.076	0.478	0.076
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCV A Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.597		(0.416)	2.181	(0.416)
<b>Total</b>	<b>18.938</b>	<b>2.782</b>	<b>0.634</b>	<b>22.354</b>	<b>3.416</b>
<b>Propane</b>					
Delivery Charge	9.290	1.609		10.899	1.609
Company Use	0.128		(0.028)	0.100	(0.028)
GCV A Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	9.350	1.609	(0.001)	10.958	1.608
Gas Supply Demand	0.402		0.076	0.478	0.076
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCV A Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.597		(0.416)	2.181	(0.416)
<b>Total</b>	<b>11.947</b>	<b>1.609</b>	<b>(0.417)</b>	<b>13.139</b>	<b>1.192</b>

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b><u>Small Commercial Sales (RS 2)</u></b>					
Monthly Basic Charge	\$31.07	\$5.37		\$36.44	\$5.37
Delivery Charge	13.542	2.341		15.883	2.341
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	0.165		1.051	1.216	1.051
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	13.767	2.341	1.050	17.158	3.391
Gas Supply Demand	0.387		0.072	0.459	0.072
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.582		(0.420)	2.162	(0.420)
Total	16.349	2.341	0.630	19.320	2.971
<b><u>Propane</u></b>					
Monthly Basic Charge	\$13.34	\$2.30		\$15.64	\$2.30
Delivery Charge	9.290	1.609		10.899	1.609
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	9.350	1.609	(0.001)	10.958	1.608
Gas Supply Demand	0.387		0.072	0.459	0.072
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.582		(0.420)	2.162	(0.420)
Total	11.932	1.609	(0.421)	13.120	1.188
<b><u>Large Commercial Sales (RS 3)</u></b>					
Monthly Basic Charge	\$186.59	\$32.36		\$218.95	\$32.36
Delivery Charge	10.835	1.879		12.714	1.879
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	10.895	1.879	(0.001)	12.773	1.883
Gas Supply Demand	0.390		0.075	0.465	0.075
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.585		(0.417)	2.168	(0.417)
Total	13.480	1.879	(0.418)	14.941	1.466

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b><u>Commercial Transport (RS 22)</u></b>					
Monthly Basic Charge	\$31.07	\$5.37		\$36.44	\$5.37
Delivery Charge	13.542	2.341		15.883	2.341
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	0.165		1.051	1.216	1.051
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Total	13.767	2.341	1.050	17.158	3.391
<b><u>Commercial Transport (RS 33)</u></b>					
Monthly Basic Charge	\$186.59	\$32.36		\$218.95	\$32.36
Delivery Charge	10.835	1.879		12.714	1.879
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Total	10.895	1.879	(0.001)	12.773	1.878
<b><u>Small Industrial Sales (RS 4)</u></b>					
Monthly Basic Charge	\$512.94	\$89.85		\$602.79	\$89.85
Delivery Charge	4.856	0.851		5.707	0.851
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	4.916	0.851	(0.001)	5.766	0.850
Gas Supply Demand	0.160		0.029	0.189	0.029
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.355		(0.463)	1.892	(0.463)
Total	7.271	0.851	(0.464)	7.658	0.387
<b><u>Commercial Interruptible Sales (RS 5)</u></b>					
Monthly Basic Charge	\$155.85	\$27.16		\$183.01	\$27.16
Delivery Charge	6.630	1.155		7.785	1.155
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	6.690	1.155	(0.001)	7.844	1.154
Gas Supply Demand	-		-	-	-
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.195		(0.492)	1.703	(0.492)
Total	8.885	1.155	(0.493)	9.547	0.662

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b><u>Seasonal Off-Peak (RS 6)</u></b>					
<b><u>Off Peak (Mar - Nov)</u></b>					
Monthly Basic Charge	\$155.54	\$26.97		\$182.51	\$26.97
Delivery Charge	9.664	1.709		11.373	1.709
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	9.724	1.709	(0.001)	11.432	1.708
Gas Supply Demand	0.204		0.043	0.247	0.043
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.399		(0.449)	1.950	(0.449)
Total	12.123	1.709	(0.450)	13.382	1.259
<b><u>Peak (Dec - Feb)</u></b>					
Monthly Basic Charge	\$0.00	\$0.00		\$0.00	\$0.00
Delivery Charge	17.616	1.709		19.325	1.709
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	17.676	1.709	(0.001)	19.384	1.708
Gas Supply Demand	0.204		0.043	0.247	0.043
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.399		(0.449)	1.950	(0.449)
Total	20.075	1.709	(0.450)	21.334	1.259
<b><u>NGV (RS 7)</u></b>					
Monthly Basic Charge	\$10.75	\$0.00		\$10.75	\$0.00
Delivery Charge	3.350	-		3.350	-
Company Use	0.128		(0.028)	0.100	(0.028)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	3.410	-	(0.001)	3.409	(0.001)
Gas Supply Demand	0.096		0.018	0.114	0.018
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.291		(0.474)	1.817	(0.474)
Total	5.701	-	(0.475)	5.226	(0.475)

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Proposed / Indicative Rates Effective January 1, 2025  
(\$/GJ unless otherwise specified)

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b><u>Rio Tinto Alcan- Supp No. 7, 7A</u></b>					
Firm	3.9391	0.6936		4.6327	0.6936
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
GCV A Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
	3.9991	0.6936	(0.0010)	4.6917	0.6926
<b><u>B.C. Hydro- Supp No. 10</u></b>					
Monthly Demand Charge	\$6,162.91	\$1,058.28		\$7,221.19	\$1,058.28
Interim Demand Charge Rider	-			-	-
Interruptible Sales/Service	4.3213	0.7592		5.0805	0.7592
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
GCV A Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<b><u>Interruptible Sales/Service</u></b>					
All Industrial T-Service Customers	4.3213	0.7592		5.0805	0.7592
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
GCV A Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<b><u>Industrial Firm Transport (RS 40)</u></b>					
Monthly Basic Charge	\$512.94	\$89.85		\$602.79	\$89.85
Firm	4.8559	0.8510		5.7069	0.8510
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
GCV A Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
	4.9159	0.8510	(0.0010)	5.7659	0.8500
Interruptible	4.3213	0.7592		5.0805	0.7592
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
GCV A Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<b><u>Large Volume Industrial (RS 80)</u></b>					
Firm	1.0000	-		1.0000	-
Company Use	-			-	-
GCV A Co. Use Rider	-			-	-
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
	1.0070	-	(0.0050)	1.0020	(0.0050)
Interruptible	1.0000	-		1.0000	-
Company Use	-			-	-
GCV A Co. Use Rider	-			-	-
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
	1.0070	-	(0.0050)	1.0020	(0.0050)

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b>Residential (RS 1)</b>					
Monthly Basic Charge	\$7.94	\$0.70		\$8.64	\$0.70
Delivery Charge	6.614	0.577		7.191	0.577
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.050)		1.011	0.961	1.011
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	6.549	0.577	1.026	8.152	1.603
Gas Supply Demand	0.402		0.076	0.478	0.076
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.597		(0.416)	2.181	(0.416)
<b>Total</b>	<b>9.146</b>	<b>0.577</b>	<b>0.610</b>	<b>10.333</b>	<b>1.187</b>
<b>Small Commercial (RS 2)</b>					
Monthly Basic Charge	\$7.95	\$0.70		\$8.65	\$0.70
Delivery Charge	4.991	0.424		5.415	0.424
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.050)		1.011	0.961	1.011
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	4.926	0.424	1.026	6.376	1.450
Gas Supply Demand	0.387		0.072	0.459	0.072
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.582		(0.420)	2.162	(0.420)
<b>Total</b>	<b>7.508</b>	<b>0.424</b>	<b>0.606</b>	<b>8.538</b>	<b>1.030</b>
<b>Large Commercial (RS 3)</b>					
Monthly Basic Charge	\$170.40	\$15.10		\$185.50	\$15.10
Delivery Charge	3.701	0.306		4.007	0.306
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	3.686	0.306	0.015	4.007	0.321
Gas Supply Demand	0.390		0.075	0.465	0.075
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.585		(0.417)	2.168	(0.417)
<b>Total</b>	<b>6.271</b>	<b>0.306</b>	<b>(0.402)</b>	<b>6.175</b>	<b>(0.096)</b>

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b>Commercial Transportation (RS 23)</b>					
Monthly Basic Charge	\$141.91	\$12.54		\$154.45	\$12.54
Delivery Charge	4.088	0.352		4.440	0.352
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	4.073	0.352	0.015	4.440	0.367
<b>Small Industrial (RS 4)</b>					
Monthly Basic Charge	\$466.38	\$41.54		\$507.92	\$41.54
Delivery Charge	2.261	0.207		2.468	0.207
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	2.246	0.207	0.015	2.468	0.222
Gas Supply Demand	0.160		0.029	0.189	0.029
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.355		(0.463)	1.892	(0.463)
Total	4.601	0.207	(0.448)	4.360	(0.241)
<b>Small Industrial Service (RS 6)</b>					
Monthly Basic Charge	\$466.23	\$41.47		\$507.70	\$41.47
Delivery Charge	2.5429	0.2262		2.7691	0.2262
Company Use	0.0530		(0.0120)	0.0410	(0.0120)
GCVA Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	2.5209	0.2262	0.0200	2.7691	0.2412
<b>Small Industrial Service (RS 10)</b>					
Monthly Basic Charge	\$3,527.76	\$316.48		\$3,844.24	\$316.48
Delivery Charge	1.1770	0.1056		1.2826	0.1056
Company Use	0.0530		(0.0120)	0.0410	(0.0120)
GCVA Co. Use Rider	(0.0750)		0.0320	(0.0430)	0.0320
LCCR Rider	0.0070		(0.0050)	0.0020	(0.0050)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	1.1620	0.1056	0.0200	1.2826	0.1206

**Pacific Northern Gas (N.E.) Ltd.**  
**(Dawson Creek Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b>Residential (RS 1)</b>					
Monthly Basic Charge	\$7.94	\$0.70		\$8.64	\$0.70
Delivery Charge	6.416	0.577		6.993	0.577
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.050)		1.011	0.961	1.011
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	6.351	0.577	1.026	7.954	1.603
Gas Supply Demand	0.402		0.076	0.478	0.076
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.597		(0.416)	2.181	(0.416)
<b>Total</b>	<b>8.948</b>	<b>0.577</b>	<b>0.610</b>	<b>10.135</b>	<b>1.187</b>
<b>Small Commercial (RS 2)</b>					
Monthly Basic Charge	\$7.95	\$0.70		\$8.65	\$0.70
Delivery Charge	4.454	0.424		4.878	0.424
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.050)		1.011	0.961	1.011
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	4.389	0.424	1.026	5.839	1.450
Gas Supply Demand	0.387		0.072	0.459	0.072
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.582		(0.420)	2.162	(0.420)
<b>Total</b>	<b>6.971</b>	<b>0.424</b>	<b>0.606</b>	<b>8.001</b>	<b>1.030</b>
<b>Large Commercial (RS 3)</b>					
Monthly Basic Charge	\$170.40	\$15.10		\$185.50	\$15.10
Delivery Charge	3.153	0.306		3.459	0.306
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	3.138	0.306	0.015	3.459	0.321
Gas Supply Demand	0.390		0.075	0.465	0.075
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.585		(0.417)	2.168	(0.417)
<b>Total</b>	<b>5.723</b>	<b>0.306</b>	<b>(0.402)</b>	<b>5.627</b>	<b>(0.096)</b>
<b>Commercial Transportation (RS 23)</b>					
Monthly Basic Charge	\$141.91	\$12.54		\$154.45	\$12.54
Delivery Charge	3.540	0.352		3.892	0.352
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	3.525	0.352	0.015	3.892	0.367

**Pacific Northern Gas (N.E.) Ltd.**  
**(Dawson Creek Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b><u>Small Industrial (RS 4)</u></b>					
Monthly Basic Charge	\$466.38	\$41.54		\$507.92	\$41.54
Delivery Charge	2.529	0.207		2.736	0.207
Company Use	0.053		(0.012)	0.041	(0.012)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	2.514	0.207	0.015	2.736	0.222
Gas Supply Demand	0.160		0.029	0.189	0.029
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.355	-	(0.463)	1.892	(0.463)
<b>Total</b>	<b>4.869</b>	<b>0.207</b>	<b>(0.448)</b>	<b>4.628</b>	<b>(0.241)</b>
<b><u>Small Industrial Service (RS 7)</u></b>					
Monthly Basic Charge	\$466.38	\$41.54		\$507.92	\$41.54
Delivery Charge	0.2050	-		0.2050	-
Company Use	-			-	-
GCVA Co. Use Rider	-			-	-
Subtotal Delivery	0.2050			0.2050	-

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**Summary of Proposed / Indicative Rates Effective January 1, 2025**  
**(\$/GJ unless otherwise specified)**

Customer Class	Decision 2024	Proposed 2025 Revenue Requirement	Indicative 2025 Gas Supply Cost Change	Proposed / Indicative Rates January 1, 2025	Rate Changes
<b>Residential (RS 1)</b>					
Monthly Basic Charge	\$9.96	\$0.00		\$9.96	\$0.00
Delivery Charge	12.855	(0.262)		12.593	(0.262)
Company Use	0.421		(0.171)	0.250	(0.171)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.219)		1.457	1.238	1.457
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	12.989	(0.262)	1.313	14.040	1.051
Gas Supply Demand	0.402		0.076	0.478	0.076
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.597		(0.416)	2.181	(0.416)
<b>Total</b>	<b>15.586</b>	<b>(0.262)</b>	<b>0.897</b>	<b>16.221</b>	<b>0.635</b>
<b>Small Commercial (RS 2)</b>					
Monthly Basic Charge	\$9.98	\$0.00		\$9.98	\$0.00
Delivery Charge	10.154	(0.190)		9.964	(0.190)
Company Use	0.421		(0.171)	0.250	(0.171)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
RSAM	(0.219)		1.457	1.238	1.457
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	10.288	(0.190)	1.313	11.411	1.123
Gas Supply Demand	0.387		0.072	0.459	0.072
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.582		(0.420)	2.162	(0.420)
<b>Total</b>	<b>12.870</b>	<b>(0.190)</b>	<b>0.893</b>	<b>13.573</b>	<b>0.703</b>
<b>Large Commercial (RS 3)</b>					
Monthly Basic Charge	\$10.01	\$0.00		\$10.01	\$0.00
Delivery Charge	8.341	(0.152)		8.189	(0.152)
Company Use	0.421		(0.171)	0.250	(0.171)
GCVA Co. Use Rider	(0.075)		0.032	(0.043)	0.032
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
Subtotal Delivery	8.694	(0.152)	(0.144)	8.398	(0.296)
Gas Supply Demand	0.390		0.075	0.465	0.075
Gas Supply Commodity	2.489		(0.368)	2.121	(0.368)
GCVA Commodity Rider	(0.294)		(0.124)	(0.418)	(0.124)
Subtotal Commodity	2.585		(0.417)	2.168	(0.417)
<b>Total</b>	<b>11.279</b>	<b>(0.152)</b>	<b>(0.561)</b>	<b>10.566</b>	<b>(0.713)</b>
<b>Industrial Transport (CNRL)</b>					
Monthly Basic Charge	\$11,643.26	\$0.00		\$11,643.26	\$0.00
Delivery Charge	0.822	(0.018)		0.804	(0.018)
LCCR Rider	0.007		(0.005)	0.002	(0.005)
Interim Rate Refund Rider	-			-	-
<b>Total</b>	<b>0.829</b>	<b>(0.018)</b>		<b>0.806</b>	<b>(0.023)</b>

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	H = G/F
<b>Residential (RS 1)</b>								
Monthly Basic Charge	\$15.64	\$2.70		<b>\$18.34</b>	\$2.70	\$17.05	<b>\$1.29</b>	7.6%
<b>Natural Gas</b>								
Delivery Charge	18.898	3.258		<b>22.156</b>	3.258	20.592	<b>1.564</b>	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	1.216	(0.817)		0.399	(0.817)	(0.133)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-			-	-			
Subtotal Delivery	20.173	2.441	(0.012)	22.602	2.429	20.487		
Gas Supply Demand	0.478		0.008	0.486	0.008	0.402		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.181		0.909	3.090	0.909	2.597		
<b>Total</b>	<b>22.354</b>	<b>2.441</b>	<b>0.897</b>	<b>25.692</b>	<b>3.338</b>	<b>23.084</b>		
<b>Propane</b>								
Delivery Charge	10.899	1.884		<b>12.783</b>	1.884	11.882	<b>0.901</b>	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002			0.002	-	0.008		
Interim Rate Refund Rider	-			-	-			
Subtotal Delivery	10.958	1.884	(0.012)	12.830	1.872	11.910		
Gas Supply Demand	0.478		0.008	0.486		0.402		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.181		0.909	3.090		2.597		
<b>Total</b>	<b>13.139</b>	<b>1.884</b>	<b>0.897</b>	<b>15.920</b>	<b>4.645</b>	<b>14.507</b>		

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	H = G/F
<b>Small Commercial Sales (RS 2)</b>								
Monthly Basic Charge	\$36.44	\$6.29		<b>\$42.73</b>	\$6.29	\$39.72	<b>\$3.01</b>	7.6%
Delivery Charge	15.883	2.741		<b>18.624</b>	2.741	17.311	<b>1.313</b>	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	1.216	(0.817)		0.399	(0.817)	(0.133)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-			-	-	-		
Subtotal Delivery	17.158	1.924	(0.012)	19.070	1.912	17.206		
Gas Supply Demand	0.459		0.007	0.466	0.007	0.387		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.162		0.908	3.070	0.908	2.582		
<b>Total</b>	<b>19.320</b>	<b>1.924</b>	<b>0.896</b>	<b>22.140</b>	<b>2.820</b>	<b>19.788</b>		
<b>Propane</b>								
Monthly Basic Charge	\$15.64	\$2.70		<b>\$18.34</b>	\$2.70	\$17.05	<b>\$1.29</b>	7.6%
Delivery Charge	10.899	1.884		<b>12.783</b>	1.884	11.882	<b>0.901</b>	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		0.000	0.002	-	0.008		
Interim Rate Refund Rider	-			-	-	-		
Subtotal Delivery	10.958	1.884	(0.012)	12.830	1.872	11.910		
Gas Supply Demand	0.459		0.007	0.466	0.007	0.387		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.162		0.908	3.070	0.908	2.582		
<b>Total</b>	<b>13.120</b>	<b>1.884</b>	<b>0.896</b>	<b>15.900</b>	<b>2.780</b>	<b>14.492</b>		
<b>Large Commercial Sales (RS 3)</b>								
Monthly Basic Charge	\$218.95	\$37.86		<b>\$256.81</b>	\$37.86	\$238.72	<b>\$18.09</b>	7.6%
Delivery Charge	12.714	2.199		<b>14.913</b>	2.199	13.862	<b>1.051</b>	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-			-	-	-		
Subtotal Delivery	12.773	2.199	(0.012)	14.960	2.187	13.890		
Gas Supply Demand	0.465		0.007	0.472	0.007	0.390		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.168		0.908	3.076	0.908	2.585		
<b>Total</b>	<b>14.941</b>	<b>2.199</b>	<b>0.896</b>	<b>18.036</b>	<b>3.095</b>	<b>16.475</b>		

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	H = G/F
<b>Commercial Transport (RS 22)</b>								
Monthly Basic Charge	\$36.44	\$6.29		\$42.73	\$6.29	\$39.72	\$3.01	7.6%
Delivery Charge	15.883	2.741		18.624	2.741	17.311	1.313	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	1.216	(0.817)		0.399	(0.817)	(0.133)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
<b>Total</b>	<b>17.158</b>	<b>1.924</b>	<b>(0.012)</b>	<b>19.070</b>	<b>1.912</b>	<b>17.206</b>		
<b>Commercial Transport (RS 33)</b>								
Monthly Basic Charge	\$218.95	\$37.86		\$256.81	\$37.86	\$238.72	\$18.09	7.6%
Delivery Charge	12.714	2.199		14.913	2.199	13.862	1.051	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
<b>Total</b>	<b>12.773</b>	<b>2.199</b>	<b>(0.012)</b>	<b>14.960</b>	<b>2.187</b>	<b>13.890</b>		
<b>Small Industrial Sales (RS 4)</b>								
Monthly Basic Charge	\$602.79	\$108.36		\$711.15	\$108.36	\$658.32	\$52.83	8.0%
Delivery Charge	5.707	1.026		6.733	1.026	6.232	0.501	8.0%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	5.766	1.026	(0.012)	6.780	1.014	6.260		
Gas Supply Demand	0.189		0.023	0.212	0.023	0.160		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.892		0.924	2.816	0.924	2.355		
<b>Total</b>	<b>7.658</b>	<b>1.026</b>	<b>0.912</b>	<b>9.596</b>	<b>1.938</b>	<b>8.615</b>		
<b>Commercial Interruptible Sales (RS 5)</b>								
Monthly Basic Charge	\$183.01	\$31.77		\$214.78	\$31.77	\$199.70	\$15.08	7.6%
Delivery Charge	7.785	1.352		9.137	1.352	8.495	0.642	7.6%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	7.844	1.352	(0.012)	9.184	1.340	8.523		
Gas Supply Demand	-		-	-	-	-		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.703		0.901	2.604	0.901	2.195		
<b>Total</b>	<b>9.547</b>	<b>1.352</b>	<b>0.889</b>	<b>11.788</b>	<b>2.241</b>	<b>10.718</b>		

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	H = G/F
<b>Seasonal Off-Peak (RS 6)</b>								
<b>Off Peak (Mar - Nov)</b>								
Monthly Basic Charge	\$182.51	\$31.57		\$214.08	\$31.57	\$199.01	\$15.07	7.6%
Delivery Charge	11.373	2.000		13.373	2.000	12.418	0.955	7.7%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	11.432	2.000	(0.012)	13.420	1.988	12.446		
Gas Supply Demand	0.247		0.002	0.249	0.002	0.204		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.950		0.903	2.853	0.903	2.399		
Total	13.382	2.000	0.891	16.273	2.891	14.845		
<b>Peak (Dec - Feb)</b>								
Monthly Basic Charge	\$0.00	\$0.00		\$0.00	\$0.00	\$0.00	\$0.00	
Delivery Charge	19.325	2.000		21.325	2.000	20.370	0.955	4.7%
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	19.384	2.000	(0.012)	21.372	1.988	20.398		
Gas Supply Demand	0.247		0.002	0.249	0.002	0.204		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.950		0.903	2.853	0.903	2.399		
Total	21.334	2.000	0.891	24.225	2.891	22.797		
<b>NGV (RS 7)</b>								
Monthly Basic Charge	\$10.75	\$0.00		\$10.75	\$0.00	\$10.75	\$0.00	
Delivery Charge	3.350	-		3.350	-	3.350		
Company Use	0.100		(0.012)	0.088	(0.012)	0.095		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	3.409		(0.012)	3.397	(0.012)	3.378		
Gas Supply Demand	0.114		0.001	0.115	0.001	0.096		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.817		0.902	2.719	0.902	2.291		
Total	5.226	-	0.890	6.116	0.890	5.669		

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b><u>Rio Tinto Alcan- Supp No. 7, 7A</u></b>								
Firm	4.6327	0.8106		5.4433	0.8106	5.0636	0.3797	7.5%
Company Use	0.1000		(0.0120)	0.0880	(0.0120)	0.0950		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
	4.6917	0.8106	(0.0120)	5.4903	0.7986	5.0916		
<b><u>B.C. Hvdro- Supp No. 10</u></b>								
Monthly Demand Charge	\$7,221.19	\$1,254.58		\$8,475.77	\$1,254.58	\$7,861.94	\$613.83	7.8%
Interruptible Sales/Service								
Interim Demand Charge Rider	-				-	-	-	
Interruptible	5.0805	0.8875		5.9680	0.8875	5.5512	0.4168	7.5%
Company Use	0.1000		(0.0120)	0.0880	(0.0120)	0.0950		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
	5.1395	0.8875	(0.0120)	6.0150	0.8755	5.5792		
<b><u>Interruptible Sales/Service</u></b>								
All Industrial T-Service Customers except West Fraser-Kitimat								
Interruptible	5.0805	0.8875		5.9680	0.8875	5.5512	0.4168	7.5%
Company Use	0.1000		(0.0120)	0.0880	(0.0120)	0.0950		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
	5.1395	0.8875	(0.0120)	6.0150	0.8755	5.5792		
<b><u>Industrial Firm Transport (RS 40)</u></b>								
Monthly Basic Charge	\$602.79	\$108.36		\$711.15	\$108.36	\$658.32	\$52.83	8.0%
Firm	5.7069	1.0259		6.7328	1.0259	6.2319	0.5009	8.0%
Company Use	0.1000		(0.0120)	0.0880	(0.0120)	0.0950		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
	5.7659		(0.0120)	6.7798	1.0139	6.2599		
Interruptible	5.0805	0.8875		5.9680	0.8875	5.5512	0.4168	7.5%
Company Use	0.1000		(0.0120)	0.0880	(0.0120)	0.0950		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
	5.1395	0.8875	(0.0120)	6.0150	0.8755	5.5792		
<b><u>RS80 Large Volume Industrials</u></b>								
Firm	1.0000	-		1.0000	-	1.0000		
Company Use	-			-	-	-		
GCV A Co. Use Rider	-			-	-	-		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
	1.0020		-	1.0020		1.0080		
Interruptible	1.0000	-		1.0000	-	1.0000		
Company Use	-			-	-	-		
GCV A Co. Use Rider	-			-	-	-		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
	1.0020		-	1.0020		1.0080		

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b>Residential (RS 1)</b>								
Monthly Basic Charge	\$8.64	\$0.76		<b>\$9.40</b>	\$0.76	\$8.64	<b>\$0.76</b>	8.8%
Delivery Charge	7.191	0.623		<b>7.814</b>	0.623	7.190	<b>0.624</b>	8.7%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	0.961	(0.806)		0.155	(0.806)	(0.198)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	8.152	(0.183)	0.008	7.977	(0.175)	6.978		
Gas Supply Demand	0.478		0.008	0.486	0.008	0.402		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.181		0.909	3.090	0.909	2.597		
<b>Total</b>	<b>10.333</b>	<b>(0.183)</b>	<b>0.917</b>	<b>11.067</b>	<b>0.734</b>	<b>9.575</b>		
<b>Small Commercial (RS 2)</b>								
Monthly Basic Charge	\$8.65	\$0.76		<b>\$9.41</b>	\$0.76	\$8.65	<b>\$0.76</b>	8.8%
Delivery Charge	5.415	0.471		<b>5.886</b>	0.471	5.415	<b>0.471</b>	8.7%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	0.961	(0.806)		0.155	(0.806)	(0.198)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	6.376	(0.335)	0.008	6.049	(0.327)	5.203		
Gas Supply Demand	0.459		0.007	0.466	0.007	0.387		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.162		0.908	3.070	0.908	2.582		
<b>Total</b>	<b>8.538</b>	<b>(0.335)</b>	<b>0.916</b>	<b>9.119</b>	<b>0.581</b>	<b>7.785</b>		
<b>Large Commercial (RS 3)</b>								
Monthly Basic Charge	\$185.50	\$16.45		<b>\$201.95</b>	\$16.45	\$185.51	<b>\$16.44</b>	8.9%
Delivery Charge	4.007	0.350		<b>4.357</b>	0.350	4.009	<b>0.348</b>	8.7%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	4.007	0.350	0.008	4.365	0.358	3.995		
Gas Supply Demand	0.465		0.002	0.467	0.002	0.390		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.168		0.903	3.071	0.903	2.585		
<b>Total</b>	<b>6.175</b>	<b>0.350</b>	<b>0.911</b>	<b>7.436</b>	<b>1.261</b>	<b>6.580</b>		

**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b>Commercial Transportation (RS 23)</b>								
Monthly Basic Charge	\$154.45	\$13.65		\$168.10	\$13.65	\$154.45	\$13.65	8.8%
Delivery Charge	4.440	0.386		4.826	0.386	4.440	0.386	8.7%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCV A Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	4.440	0.386	0.008	4.834	0.394	4.426		
<b>Small Industrial (RS 4)</b>								
Monthly Basic Charge	\$507.92	\$45.29		\$553.21	\$45.29	\$507.97	\$45.24	8.9%
Delivery Charge	2.468	0.217		2.685	0.217	2.468	0.217	8.8%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCV A Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	2.468	0.217	0.008	2.693	0.225	2.454		
Gas Supply Demand	0.189		0.023	0.212	0.023	0.160		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCV A Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.892		0.924	2.816	0.924	2.355		
Total	4.360	0.217	0.932	5.509	1.149	4.809		
<b>Small Industrial Service (RS 6)</b>								
Monthly Basic Charge	\$507.70	\$45.20		\$552.90	\$45.20	\$507.74	\$45.16	8.9%
Delivery Charge	2.7691	0.2429		3.0120	0.2429	2.7693	0.2427	8.8%
Company Use	0.0410		0.0080	0.0490	0.0080	0.0530		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	2.7691	0.2429	0.0080	3.0200	0.2509	2.7553		
<b>Small Industrial Service (RS 10)</b>								
Monthly Basic Charge	\$3,844.24	\$345.50		\$4,189.74	\$345.50	\$3,844.95	\$344.79	9.0%
Delivery Charge	1.2826	0.1129		1.3955	0.1129	1.2828	0.1127	8.8%
Company Use	0.0410		0.0080	0.0490	0.0080	0.0530		
GCV A Co. Use Rider	(0.0430)		-	(0.0430)	-	(0.0750)		
LCCR Rider	0.0020		-	0.0020	-	0.0080		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	1.2826	0.1129	0.0080	1.4035	0.1209	1.2688		

**Pacific Northern Gas (N.E.) Ltd.**  
**(Dawson Creek Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b>Residential (RS 1)</b>								
Monthly Basic Charge	\$8.64	\$0.76		<b>\$9.40</b>	\$0.76	\$8.64	<b>\$0.76</b>	8.8%
Delivery Charge	6.993	0.637		<b>7.630</b>	0.637	6.992	<b>0.638</b>	9.1%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	0.961	(0.806)	-	0.155	(0.806)	(0.198)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	7.954	(0.169)	0.008	7.793	(0.161)	6.780		
Gas Supply Demand	0.478		0.008	0.486	0.008	0.402		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.181		0.909	3.090	0.909	2.597		
<b>Total</b>	<b>10.135</b>	<b>(0.169)</b>	<b>0.917</b>	<b>10.883</b>	<b>0.748</b>	<b>9.377</b>		
<b>Small Commercial (RS 2)</b>								
Monthly Basic Charge	\$8.65	\$0.76		<b>\$9.41</b>	\$0.76	\$8.65	<b>\$0.76</b>	8.8%
Delivery Charge	4.878	0.444		<b>5.322</b>	0.444	4.878	<b>0.444</b>	9.1%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	0.961	(0.806)	-	0.155	(0.806)	(0.198)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	5.839	(0.362)	0.008	5.485	(0.354)	4.666		
Gas Supply Demand	0.459		0.007	0.466	0.007	0.387		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.162		0.908	3.070	0.908	2.582		
<b>Total</b>	<b>8.001</b>	<b>(0.362)</b>	<b>0.916</b>	<b>8.555</b>	<b>0.554</b>	<b>7.248</b>		
<b>Large Commercial (RS 3)</b>								
Monthly Basic Charge	\$185.50	\$16.45		<b>\$201.95</b>	\$16.45	\$185.51	<b>\$16.44</b>	8.9%
Delivery Charge	3.459	0.316		<b>3.775</b>	0.316	3.461	<b>0.314</b>	9.1%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	3.459	0.316	0.008	3.783	0.324	3.447		
Gas Supply Demand	0.465		0.002	0.467	0.002	0.390		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.168		0.903	3.071	0.903	2.585		
<b>Total</b>	<b>5.627</b>	<b>0.316</b>	<b>0.911</b>	<b>6.854</b>	<b>1.227</b>	<b>6.032</b>		

**Pacific Northern Gas (N.E.) Ltd.**  
**(Dawson Creek Division)**

**Summary of Provisional / Indicative Rates Effective January 1, 2026**  
**(\$/GJ unless otherwise specified)**

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b>Commercial Transportation (RS 23)</b>								
Monthly Basic Charge	\$154.45	\$13.65		\$168.10	\$13.65	\$154.45	\$13.65	8.8%
Delivery Charge	3.892	0.356		4.248	0.356	3.892	0.356	9.1%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	3.892	0.356	0.008	4.256	0.364	3.878		
<b>Small Industrial (RS 4)</b>								
Monthly Basic Charge	\$507.92	\$45.29		\$553.21	\$45.29	\$507.97	\$45.24	8.9%
Delivery Charge	2.736	0.251		2.987	0.251	2.736	0.251	9.2%
Company Use	0.041		0.008	0.049	0.008	0.053		
GCVA Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	2.736	0.251	0.008	2.995	0.259	2.722		
Gas Supply Demand	0.189		0.023	0.212	0.023	0.160		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVA Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	1.892		0.924	2.816	0.924	2.355		
Total	4.628	0.251	0.932	5.811	1.183	5.077		
<b>Small Industrial Service (RS 7)</b>								
Monthly Basic Charge	\$507.92	\$45.29		\$553.21	\$45.29	\$507.97	\$45.24	8.9%
Delivery Charge	0.2050	-		0.2050	-	0.2050	-	
Company Use	-			-	-	-		
GCVA Co. Use Rider	-			-	-	-		
Subtotal Delivery	0.2050	-	-	0.2050	-	0.2050		

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

Summary of Provisional / Indicative Rates Effective January 1, 2026  
(\$/GJ unless otherwise specified)

Customer Class	Provisional Decision Rates Applicable January 1, 2025	Provisional Decision 2026 Revenue Requirement	Indicative 2026 Gas Supply Cost Change	Provisional Decision Revised Interim Rates Applicable January 1, 2026	Provisional 2026 Rate Changes	Adjusted Interim Rates Currently in Effect (May 1, 2025 and January 1, 2026)	Proposed Revised Interim Rate Changes	Illustrative Rate Change (%)
	A	B	C	D = A+B / A+C	E = B+C	F	G = D-F	G = D-F
<b>Residential (RS 1)</b>								
Monthly Basic Charge	\$9.96	\$0.00		\$9.96	\$0.00	\$9.96	\$0.00	
Delivery Charge	12.593	(0.252)		12.341	(0.252)	12.589	(0.248)	-2.0%
Company Use	0.250		(0.236)	0.014	(0.236)	0.015		
GCVa Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	1.238	(1.185)		0.053	(1.185)	(0.229)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	14.040	(1.437)	(0.236)	12.367	(1.673)	12.308		
Gas Supply Demand	0.478		0.008	0.486	0.008	0.402		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVa Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.181		0.909	3.090	0.909	2.597		
<b>Total</b>	<b>16.221</b>	<b>(1.437)</b>	<b>0.673</b>	<b>15.457</b>	<b>(0.764)</b>	<b>14.905</b>		
<b>Small Commercial (RS 2)</b>								
Monthly Basic Charge	\$9.98	\$0.00		\$9.98	\$0.00	\$9.98	\$0.00	
Delivery Charge	9.964	(0.181)		9.783	(0.181)	9.961	(0.178)	-1.8%
Company Use	0.250		(0.236)	0.014	(0.236)	0.015		
GCVa Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
RSAM	1.238	(1.185)		0.053	(1.185)	(0.229)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	11.411	(1.366)	(0.236)	9.809	(1.602)	9.680		
Gas Supply Demand	0.459		0.007	0.466	0.007	0.387		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVa Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.162		0.908	3.070	0.901	2.582		
<b>Total</b>	<b>13.573</b>	<b>(1.366)</b>	<b>0.672</b>	<b>12.879</b>	<b>(0.701)</b>	<b>12.262</b>		
<b>Large Commercial (RS 3)</b>								
Monthly Basic Charge	\$10.01	\$0.00		\$10.01	\$0.00	\$10.01	\$0.00	
Delivery Charge	8.189	(0.145)		8.044	(0.145)	8.185	(0.141)	-1.7%
Company Use	0.250		(0.236)	0.014	(0.236)	0.015		
GCVa Co. Use Rider	(0.043)		-	(0.043)	-	(0.075)		
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	8.398	(0.145)	(0.236)	8.017	(0.381)	8.133		
Gas Supply Demand	0.465		0.002	0.467		0.390		
Gas Supply Commodity	2.121		0.901	3.022	0.901	2.489		
GCVa Commodity Rider	(0.418)		-	(0.418)	-	(0.294)		
Subtotal Commodity	2.168		0.903	3.071	0.901	2.585		
<b>Total</b>	<b>10.566</b>	<b>(0.145)</b>	<b>0.667</b>	<b>11.088</b>	<b>0.520</b>	<b>10.718</b>		
<b>Industrial Transport (CNRL)</b>								
Monthly Basic Charge	\$11,643.26	\$0.00		\$11,643.26	\$0.00	\$11,643.26	\$0.00	
Delivery Charge	0.804	(0.018)		0.786	(0.018)	0.804	(0.018)	-2.2%
LCCR Rider	0.002		-	0.002	-	0.008		
Interim Rate Refund Rider	-		-	-	-	-		
Subtotal Delivery	0.806	(0.018)		0.788	(0.018)	0.812		

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit D – Rate Summaries – January 1, 2025 to March 1, 2026**

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Residential (RS1)</b>							
Monthly Basic Charge	\$ 14.24	\$ 2.81	\$ 17.05	\$ -	\$ 17.05	\$ 1.29	\$ 18.34
Delivery Charge	17.213	3.379	20.592	-	20.592	1.564	22.156
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	17.360	3.379	20.739	(0.052)	20.687	1.564	22.251
Interim Rate Adjustment Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	-	-	-	-	-	-	-
LCCR Rider	0.966	0.250	1.216	(1.349)	(0.133)	-	(0.133)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	18.253	3.629	21.882	(1.395)	20.487	1.564	22.051
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.891	-	2.891	-	2.891	-	2.891
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.597	-	2.597	-	2.597	-	2.597
<b>Total</b>	<b>20.850</b>	<b>3.629</b>	<b>24.479</b>	<b>(1.395)</b>	<b>23.084</b>	<b>1.564</b>	<b>24.648</b>
<b>Residential (RS1P Propane)</b>							
Monthly Basic Charge	\$ 14.24	\$ 2.81	\$ 17.05	\$ -	\$ 17.05	\$ 1.29	\$ 18.34
Delivery Charge	9.916	1.966	11.882	-	11.882	0.901	12.783
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	10.063	1.966	12.029	(0.052)	11.977	0.901	12.878
Interim Rate Adj. Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	-	-	-	-	-	-	-
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	9.990	1.966	11.956	(0.046)	11.910	0.901	12.811
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.891	-	2.891	-	2.891	-	2.891
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.597	-	2.597	-	2.597	-	2.597
<b>Total</b>	<b>12.587</b>	<b>1.966</b>	<b>14.553</b>	<b>(0.046)</b>	<b>14.507</b>	<b>0.901</b>	<b>15.408</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Small Commercial Sales (RS2)</b>							
Monthly Basic Charge	\$ 33.19	\$ 6.53	\$ 39.72	\$ -	\$ 39.72	\$ 3.01	\$ 42.73
Delivery Charge	14.465	2.846	17.311	-	17.311	1.313	18.624
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	14.612	2.846	17.458	(0.052)	17.406	1.313	18.719
Interim Rate Adjustment Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	-	-	-	-	-	-	-
LCCR Rider	0.966	0.250	1.216	(1.349)	(0.133)	-	(0.133)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	15.505	3.096	18.601	(1.395)	17.206	1.313	18.519
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.876	-	2.876	-	2.876	-	2.876
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.582	-	2.582	-	2.582	-	2.582
<b>Total</b>	<b>18.087</b>	<b>3.096</b>	<b>21.183</b>	<b>(1.395)</b>	<b>19.788</b>	<b>1.313</b>	<b>21.101</b>
<b>Small Commercial (RS2P Propane)</b>							
Monthly Basic Charge	\$ 14.24	\$ 2.81	\$ 17.05	\$ -	\$ 17.05	\$ 1.29	\$ 18.34
Delivery Charge	9.916	1.966	11.882	-	11.882	0.901	12.783
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	10.063	1.966	12.029	(0.052)	11.977	0.901	12.878
Interim Rate Adj. Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	-	-	-	-	-	-	-
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	9.990	1.966	11.956	(0.046)	11.910	0.901	12.811
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.876	-	2.876	-	2.876	-	2.876
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.582	-	2.582	-	2.582	-	2.582
<b>Total</b>	<b>12.572</b>	<b>1.966</b>	<b>14.538</b>	<b>(0.046)</b>	<b>14.492</b>	<b>0.901</b>	<b>15.393</b>
<b>Large Commercial Sales (RS3)</b>							
Monthly Basic Charge	\$199.36	\$39.36	\$238.72	\$ -	\$238.72	\$18.09	\$256.81
Delivery Charge	11.576	2.286	13.862	-	13.862	1.051	14.913
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	11.723	2.286	14.009	(0.052)	13.957	1.051	15.008
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	11.650	2.286	13.936	(0.046)	13.890	1.051	14.941
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.879	-	2.879	-	2.879	-	2.879
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.585	-	2.585	-	2.585	-	2.585
<b>Total</b>	<b>14.235</b>	<b>2.286</b>	<b>16.521</b>	<b>(0.046)</b>	<b>16.475</b>	<b>1.051</b>	<b>17.526</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Small Industrial (RS4)</b>							
Monthly Basic Charge	\$ 548.69	\$ 109.63	\$ 658.32	\$ -	\$ 658.32	\$ 52.83	\$ 711.15
Delivery Charge	5.194	1.038	6.232	-	6.232	0.501	6.733
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	5.341	1.038	6.379	(0.052)	6.327	0.501	6.828
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	5.268	1.038	6.306	(0.046)	6.260	0.501	6.761
Gas Supply Commodity	0.160	-	0.160	-	0.160	-	0.160
GCVA Commodity Rider	2.489	-	2.489	-	2.489	-	2.489
Subtotal Commodity	2.649	-	2.649	-	2.649	-	2.649
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.355	-	2.355	-	2.355	-	2.355
<b>Total</b>	<b>7.623</b>	<b>1.038</b>	<b>8.661</b>	<b>(0.046)</b>	<b>8.615</b>	<b>0.501</b>	<b>9.116</b>
<b>Commercial Interruptible (RS5)</b>							
Monthly Basic Charge	\$ 166.62	\$ 33.08	\$ 199.70	\$ -	\$ 199.70	\$ 15.08	\$ 214.78
Delivery Charge	7.087	1.408	8.495	-	8.495	0.642	9.137
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	7.234	1.408	8.642	(0.052)	8.590	0.642	9.232
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	7.161	1.408	8.569	(0.046)	8.523	0.642	9.165
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
GCVA Commodity Rider	2.489	-	2.489	-	2.489	-	2.489
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.195	-	2.195	-	2.195	-	2.195
<b>Total</b>	<b>9.356</b>	<b>1.408</b>	<b>10.764</b>	<b>(0.046)</b>	<b>10.718</b>	<b>0.642</b>	<b>11.360</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Seasonal Off-Peak (RS6)</b>							
<b>Off Peak (Mar-Nov)</b>							
Monthly Basic Charge	\$ 166.20	\$ 32.81	\$ 199.01	\$ -	\$ 199.01	\$ 15.07	\$ 214.08
Delivery Charge	10.340	2.078	12.418	-	12.418	0.955	13.373
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
	10.487	2.078	12.565	(0.052)	12.513	0.955	13.468
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	10.414	2.078	12.492	(0.046)	12.446	0.955	13.401
Gas Supply Demand	0.204	-	0.204	-	0.204	-	0.204
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.693	-	2.693	-	2.693	-	2.693
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.399	-	2.399	-	2.399	-	2.399
<b>Total</b>	<b>12.813</b>	<b>2.078</b>	<b>14.891</b>	<b>(0.046)</b>	<b>14.845</b>	<b>0.955</b>	<b>15.800</b>
<b>Peak (Dec-Feb)</b>							
Monthly Basic Charge	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Delivery Charge	18.292	2.078	20.370	-	20.370	0.955	21.325
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
	18.439	2.078	20.517	(0.052)	20.465	0.955	21.420
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	18.366	2.078	20.444	(0.046)	20.398	0.955	21.353
Gas Supply Demand	0.204	-	0.204	-	0.204	-	0.204
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.693	-	2.693	-	2.693	-	2.693
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.399	-	2.399	-	2.399	-	2.399
<b>Total</b>	<b>20.765</b>	<b>2.078</b>	<b>22.843</b>	<b>(0.046)</b>	<b>22.797</b>	<b>0.955</b>	<b>23.752</b>
<b>NGV (RS7)</b>							
Monthly Basic Charge	\$ 10.75	\$ -	\$ 10.75	\$ -	\$ 10.75	\$ -	\$ 10.75
Delivery Charge	3.350	-	3.350	-	3.350	-	3.350
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
	3.497	-	3.497	(0.052)	3.445	-	3.445
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	3.424	-	3.424	(0.046)	3.378	-	3.378
Gas Supply Demand	0.096	-	0.096	-	0.096	-	0.096
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.585	-	2.585	-	2.585	-	2.585
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.291	-	2.291	-	2.291	-	2.291
<b>Total</b>	<b>5.715</b>	<b>-</b>	<b>5.715</b>	<b>(0.046)</b>	<b>5.669</b>	<b>-</b>	<b>5.669</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Small Commercial Transportation (RS22)</b>							
Monthly Basic Charge	\$ 33.19	\$ 6.53	\$ 39.72	\$ -	\$ 39.72	\$ 3.01	\$ 42.73
Delivery Charge	14.465	2.846	17.311	-	17.311	1.313	18.624
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	14.612	2.846	17.458	(0.052)	17.406	1.313	18.719
GCVa Co. Use Rider	-	-	-	-	-	-	-
RSAM	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.966	0.250	1.216	(1.349)	(0.133)	-	(0.133)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
<b>Total Delivery</b>	<b>15.505</b>	<b>3.096</b>	<b>18.601</b>	<b>(1.395)</b>	<b>17.206</b>	<b>1.313</b>	<b>18.519</b>
<b>Large Commercial Transportation (RS33)</b>							
Monthly Basic Charge	\$ 199.36	\$ 39.36	\$ 238.72	\$ -	\$ 238.72	\$ 18.09	\$ 256.81
Delivery Charge	11.576	2.286	13.862	-	13.862	1.051	14.913
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	11.723	2.286	14.009	(0.052)	13.957	1.051	15.008
GCVa Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
<b>Total Delivery</b>	<b>11.650</b>	<b>2.286</b>	<b>13.936</b>	<b>(0.046)</b>	<b>13.890</b>	<b>1.051</b>	<b>14.941</b>
<b>PNG Company Use Rate</b>							
	2.115	-	2.115	1.141	3.256	-	3.256

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Residential (RS1-LCE)</b>							
Monthly Basic Charge	\$ 14.24	\$ 2.81	\$ 17.05	\$ -	\$ 17.05	\$ 1.29	\$ 18.34
Delivery Charge	17.213	3.379	20.592	-	20.592	1.564	22.156
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	17.360	3.379	20.739	(0.052)	20.687	1.564	22.251
Interim Rate Adjustment Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	-	-	-	-	-	-	-
LCCR Rider	0.966	0.250	1.216	(1.349)	(0.133)	-	(0.133)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	18.253	3.629	21.882	(1.395)	20.487	1.564	22.051
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
Low Carbon Commodity Charge	2.891	-	2.891	-	2.891	-	2.891
GCVA Commodity Rider	27.500	-	27.500	-	27.500	-	27.500
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.097	-	30.097	-	30.097	-	30.097
<b>Total</b>	<b>48.350</b>	<b>3.629</b>	<b>51.979</b>	<b>(1.395)</b>	<b>50.584</b>	<b>1.564</b>	<b>52.148</b>
<b>Small Commercial Sales (RS2-LCE)</b>							
Monthly Basic Charge	\$ 33.19	\$ 6.53	\$ 39.72	\$ -	\$ 39.72	\$ 3.01	\$ 42.73
Delivery Charge	14.465	2.846	17.311	-	17.311	1.313	18.624
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
GCVA Co. Use Rider	14.612	2.846	17.458	(0.052)	17.406	1.313	18.719
Interim Rate Adjustment Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	-	-	-	-	-	-	-
LCCR Rider	0.966	0.250	1.216	(1.349)	(0.133)	-	(0.133)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	15.505	3.096	18.601	(1.395)	17.206	1.313	18.519
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
Low Carbon Commodity Charge	2.876	-	2.876	-	2.876	-	2.876
GCVA Commodity Rider	27.500	-	27.500	-	27.500	-	27.500
Subtotal Commodity	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.082	-	30.082	-	30.082	-	30.082
<b>Total</b>	<b>45.587</b>	<b>3.096</b>	<b>48.683</b>	<b>(1.395)</b>	<b>47.288</b>	<b>1.313</b>	<b>48.601</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Large Commercial Sales (RS3-LCE)</b>							
Monthly Basic Charge	\$199.36	39.36	\$238.72	-	\$238.72	18.09	<b>\$256.81</b>
Delivery Charge	11.576	2.286	13.862	-	13.862	1.051	<b>14.913</b>
Company Use	0.147	-	0.147	(0.052)	0.095	-	<b>0.095</b>
	11.723	2.286	14.009	(0.052)	13.957	1.051	<b>15.008</b>
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	<b>(0.075)</b>
LCCR Rider	0.002	-	0.002	0.006	0.008	-	<b>0.008</b>
Subtotal Delivery	11.650	2.286	13.936	(0.046)	13.890	1.051	<b>14.941</b>
Gas Supply Demand	0.390	-	0.390	-	0.390	-	<b>0.390</b>
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	<b>2.489</b>
	2.879	-	2.879	-	2.879	-	<b>2.879</b>
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	<b>27.500</b>
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	<b>(0.294)</b>
Subtotal Commodity	30.085	-	30.085	-	30.085	-	<b>30.085</b>
<b>Total</b>	<b>41.735</b>	<b>2.286</b>	<b>44.021</b>	<b>(0.046)</b>	<b>43.975</b>	<b>1.051</b>	<b>45.026</b>
<b>Small Industrial (RS4-LCE)</b>							
Monthly Basic Charge	\$ 548.69	\$ 109.63	\$ 658.32	\$ -	\$ 658.32	\$ 52.83	<b>\$ 711.15</b>
Delivery Charge	5.194	1.038	6.232	-	6.232	0.501	<b>6.733</b>
Company Use	0.147	-	0.147	(0.052)	0.095	-	<b>0.095</b>
	5.341	1.038	6.379	(0.052)	6.327	0.501	<b>6.828</b>
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	<b>(0.075)</b>
LCCR Rider	0.002	-	0.002	0.006	0.008	-	<b>0.008</b>
Subtotal Delivery	5.268	1.038	6.306	(0.046)	6.260	0.501	<b>6.761</b>
Gas Supply Demand	0.160	-	0.160	-	0.160	-	<b>0.160</b>
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	<b>2.489</b>
	2.649	-	2.649	-	2.649	-	<b>2.649</b>
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	<b>27.500</b>
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	<b>(0.294)</b>
Subtotal Commodity	29.855	-	29.855	-	29.855	-	<b>29.855</b>
<b>Total</b>	<b>35.123</b>	<b>1.038</b>	<b>36.161</b>	<b>(0.046)</b>	<b>36.115</b>	<b>0.501</b>	<b>36.616</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Commercial Interruptible (RS5-LCE)</b>							
Monthly Basic Charge	\$ 166.62	\$ 33.08	\$ 199.70	\$ -	\$ 199.70	\$ 15.08	\$ 214.78
Delivery Charge	7.087	1.408	8.495	-	8.495	0.642	9.137
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	7.234	1.408	8.642	(0.052)	8.590	0.642	9.232
GCUA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	7.161	1.408	8.569	(0.046)	8.523	0.642	9.165
Gas Supply Commodity	-	-	-	-	-	-	-
Low Carbon Commodity Charge	2.489	-	2.489	-	2.489	-	2.489
GCUA Commodity Rider	2.489	-	2.489	-	2.489	-	2.489
Subtotal Commodity	27.500	-	27.500	-	27.500	-	27.500
Total	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	29.695	-	29.695	-	29.695	-	29.695
Total	36.856	1.408	38.264	(0.046)	38.218	0.642	38.860
<b>Seasonal Off-Peak (RS6-LCE)</b>							
<b>Off Peak (Mar-Nov)</b>							
Monthly Basic Charge	\$ 166.20	\$ 32.81	\$ 199.01	\$ -	\$ 199.01	\$ 15.07	\$ 214.08
Delivery Charge	10.340	2.078	12.418	-	12.418	0.955	13.373
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	10.487	2.078	12.565	(0.052)	12.513	0.955	13.468
GCUA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	10.414	2.078	12.492	(0.046)	12.446	0.955	13.401
Gas Supply Commodity	0.204	-	0.204	-	0.204	-	0.204
Low Carbon Commodity Charge	2.489	-	2.489	-	2.489	-	2.489
GCUA Commodity Rider	2.693	-	2.693	-	2.693	-	2.693
Subtotal Commodity	27.500	-	27.500	-	27.500	-	27.500
Total	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	29.899	-	29.899	-	29.899	-	29.899
Total	40.313	2.078	42.391	(0.046)	42.345	0.955	43.300
<b>Peak (Dec-Feb)</b>							
Monthly Basic Charge	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
Delivery Charge	18.292	2.078	20.370	-	20.370	0.955	21.325
Company Use	0.147	-	0.147	(0.052)	0.095	-	0.095
Interim Rate Adjustment Rider	18.439	2.078	20.517	(0.052)	20.465	0.955	21.420
GCUA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	18.366	2.078	20.444	(0.046)	20.398	0.955	21.353
Gas Supply Commodity	0.204	-	0.204	-	0.204	-	0.204
Low Carbon Commodity Charge	2.489	-	2.489	-	2.489	-	2.489
GCUA Commodity Rider	2.693	-	2.693	-	2.693	-	2.693
Subtotal Commodity	27.500	-	27.500	-	27.500	-	27.500
Total	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	29.899	-	29.899	-	29.899	-	29.899
Total	48.265	2.078	50.343	(0.046)	50.297	0.955	51.252

Pacific Northern Gas Ltd.  
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Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b><u>Rio Tinto Alcan- Supp No. 7, 7A</u></b>							
Firm Delivery	4.2160	0.8476	5.0636	-	5.0636	0.3797	5.4433
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
Interim Rate Adjustment Rider	4.3630	0.8476	5.2106	(0.0520)	5.1586	0.3797	5.5383
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>4.2900</b>	<b>0.8476</b>	<b>5.1376</b>	<b>(0.0460)</b>	<b>5.0916</b>	<b>0.3797</b>	<b>5.4713</b>
<b><u>Rio Tinto Alcan- Supp No. 7, 7A - Interruptible</u></b>							
Interruptible Delivery	4.6239	0.9273	5.5512	-	5.5512	0.4168	5.9680
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
Interim Rate Adjustment Rider	4.7709	0.9273	5.6982	(0.0520)	5.6462	0.4168	6.0630
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>4.6979</b>	<b>0.9273</b>	<b>5.6252</b>	<b>(0.0460)</b>	<b>5.5792</b>	<b>0.4168</b>	<b>5.9960</b>
<b><u>B.C. Hydro- Supp No. 10</u></b>							
Monthly Demand Charge	\$ 6,590.17	\$ 1,271.77	\$ 7,861.94	\$ -	\$ 7,861.94	\$ 613.83	\$ 8,475.77
Interim Monthly Rate Adjustment Rider	0.00	-	0.00	-	0.00	-	0.00
	\$ 6,590.17	\$ 1,271.77	\$ 7,861.94	\$ -	\$ 7,861.94	\$ 613.83	\$ 8,475.77
Interruptible Delivery	4.6239	0.9273	5.5512	-	5.5512	0.4168	5.9680
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
Interim Rate Adjustment Rider	4.7709	0.9273	5.6982	(0.0520)	5.6462	0.4168	6.0630
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>4.6979</b>	<b>0.9273</b>	<b>5.6252</b>	<b>(0.0460)</b>	<b>5.5792</b>	<b>0.4168</b>	<b>5.9960</b>
<b><u>Industrial Interruptible Transportation Service</u></b>							
Interruptible Delivery	4.6239	0.9273	5.5512	-	5.5512	0.4168	5.9680
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
Interim Rate Adjustment Rider	4.7709	0.9273	5.6982	(0.0520)	5.6462	0.4168	6.0630
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>4.6979</b>	<b>0.9273</b>	<b>5.6252</b>	<b>(0.0460)</b>	<b>5.5792</b>	<b>0.4168</b>	<b>5.9960</b>

Pacific Northern Gas Ltd.  
(PNG-West Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>RS40 - Firm Transportation</b>							
Monthly Fixed Charge	\$ 548.69	\$ 109.63	\$ 658.32	\$ -	\$ 658.32	\$ 52.83	\$ 711.15
Delivery Charge	5.1943	1.0376	6.2319	-	6.2319	0.5009	6.7328
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
	5.3413	1.0376	6.3789	(0.0520)	6.3269	0.5009	6.8278
Interim Rate Adjustment Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
GCVA Co. Use Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>5.2683</b>	<b>1.0376</b>	<b>6.3059</b>	<b>(0.0460)</b>	<b>6.2599</b>	<b>0.5009</b>	<b>6.7608</b>
<b>RS40 - Interruptible Transportation Service</b>							
Delivery Charge	4.6239	0.9273	5.5512	-	5.5512	0.4168	5.9680
Company Use	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
	4.7709	0.9273	5.6982	(0.0520)	5.6462	0.4168	6.0630
Interim Rate Adjustment Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
GCVA Co. Use Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>4.6979</b>	<b>0.9273</b>	<b>5.6252</b>	<b>(0.0460)</b>	<b>5.5792</b>	<b>0.4168</b>	<b>5.9960</b>
<b>RS80 - Large Volume Industrial Transportation Service</b>							
Delivery Charge Firm	1.0000	-	1.0000	-	1.0000	-	1.0000
Company Use	0.0000	-	0.0000	-	0.0000	-	0.0000
	1.0000	-	1.0000	-	1.0000	-	1.0000
Interim Rate Adjustment Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>1.0020</b>	<b>-</b>	<b>1.0020</b>	<b>0.0060</b>	<b>1.0080</b>	<b>-</b>	<b>1.0080</b>
<b>RS80 - Interruptible Transportation Service</b>							
Interruptible Delivery	1.0000	-	1.0000	-	1.0000	-	1.0000
Company Use	0.0000	-	0.0000	-	0.0000	-	0.0000
	1.0000	-	1.0000	-	1.0000	-	1.0000
Interim Rate Adjustment Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
GCVA Co. Use Rider	0.0000	-	0.0000	-	0.0000	-	0.0000
LCCR Rider	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>1.0020</b>	<b>-</b>	<b>1.0020</b>	<b>0.0060</b>	<b>1.0080</b>	<b>-</b>	<b>1.0080</b>

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Residential (RS1)</b>							
Monthly Basic Charge	\$ 8.28	\$ 0.36	\$ 8.64	\$ -	\$ 8.64	\$ 0.76	\$ 9.40
Delivery Charge	6.893	0.297	7.190	-	7.190	0.624	7.814
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	6.942	0.297	7.239	0.004	7.243	0.624	7.867
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	7.796	0.331	8.127	(1.149)	6.978	0.624	7.602
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.597	-	2.597	-	2.597	-	2.597
<b>Total</b>	<b>10.393</b>	<b>0.331</b>	<b>10.724</b>	<b>(1.149)</b>	<b>9.575</b>	<b>0.624</b>	<b>10.199</b>
<b>Small Commercial (RS2)</b>							
Monthly Basic Charge	\$ 8.29	\$ 0.36	\$ 8.65	\$ -	\$ 8.65	\$ 0.76	\$ 9.41
Delivery Charge	5.197	0.218	5.415	-	5.415	0.471	5.886
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	5.246	0.218	5.464	0.004	5.468	0.471	5.939
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	6.100	0.252	6.352	(1.149)	5.203	0.471	5.674
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.582	-	2.582	-	2.582	-	2.582
<b>Total</b>	<b>8.682</b>	<b>0.252</b>	<b>8.934</b>	<b>(1.149)</b>	<b>7.785</b>	<b>0.471</b>	<b>8.256</b>
<b>Large Commercial (RS3)</b>							
Monthly Basic Charge	\$ 177.73	\$ 7.78	\$ 185.51	\$ -	\$ 185.51	\$ 16.44	\$ 201.95
Delivery Charge	3.852	0.157	4.009	-	4.009	0.348	4.357
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	3.901	0.157	4.058	0.004	4.062	0.348	4.410
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	3.828	0.157	3.985	0.010	3.995	0.348	4.343
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.585	-	2.585	-	2.585	-	2.585
<b>Total</b>	<b>6.413</b>	<b>0.157</b>	<b>6.570</b>	<b>0.010</b>	<b>6.580</b>	<b>0.348</b>	<b>6.928</b>

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Small Industrial (RS4)</b>							
Monthly Basic Charge	\$ 486.65	\$ 21.32	\$ 507.97	\$ -	\$ 507.97	\$ 45.24	\$ 553.21
Delivery Charge	2.362	0.106	2.468	-	2.468	0.217	2.685
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
Interim Rate Adjustment Rider	2.411	0.106	2.517	0.004	2.521	0.217	2.738
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
Gas Supply Demand	2.338	0.106	2.444	0.010	2.454	0.217	2.671
Gas Supply Commodity	0.160	-	0.160	-	0.160	-	0.160
GCVA Commodity Rider	2.489	-	2.489	-	2.489	-	2.489
Subtotal Commodity	2.649	-	2.649	-	2.649	-	2.649
	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
<b>Total</b>	<b>4.693</b>	<b>0.106</b>	<b>4.799</b>	<b>0.010</b>	<b>4.809</b>	<b>0.217</b>	<b>5.026</b>
<b>Small Industrial Transportation &gt;15,000 GJ (RS6)</b>							
Monthly Basic Charge	\$ 486.46	\$ 21.28	\$ 507.74	\$ -	\$ 507.74	\$ 45.16	\$ 552.90
Delivery Charge	2.6532	0.1161	2.7693	-	2.7693	0.2427	3.0120
Company Use	0.0490	-	0.0490	0.0040	0.0530	-	0.0530
Interim Rate Adjustment Rider	2.7022	0.1161	2.8183	0.0040	2.8223	0.2427	3.0650
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
Subtotal Delivery	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>2.6292</b>	<b>0.1161</b>	<b>2.7453</b>	<b>0.0100</b>	<b>2.7553</b>	<b>0.2427</b>	<b>2.9980</b>
<b>Small Industrial Transportation (RS10)</b>							
Monthly Basic Charge	\$ 3,683.35	\$ 161.60	\$ 3,844.95	\$ -	\$ 3,844.95	\$ 344.79	\$ 4,189.74
Delivery Charge	1.2289	0.0539	1.2828	-	1.2828	0.1127	1.3955
Company Use	0.0490	-	0.0490	0.0040	0.0530	-	0.0530
Interim Rate Adjustment Rider	1.2779	0.0539	1.3318	0.0040	1.3358	0.1127	1.4485
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.0750)	-	(0.0750)	-	(0.0750)	-	(0.0750)
Subtotal Delivery	0.0020	-	0.0020	0.0060	0.0080	-	0.0080
<b>Total Delivery</b>	<b>1.2049</b>	<b>0.0539</b>	<b>1.2588</b>	<b>0.0100</b>	<b>1.2688</b>	<b>0.1127</b>	<b>1.3815</b>
<b>Commercial Transportation (RS23)</b>							
Monthly Basic Charge	\$ 147.99	\$ 6.46	\$ 154.45	\$ -	\$ 154.45	\$ 13.65	\$ 168.10
Delivery Charge	4.259	0.181	4.440	-	4.440	0.386	4.826
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
Interim Rate Adjustment Rider	4.308	0.181	4.489	0.004	4.493	0.386	4.879
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
Subtotal Delivery	0.002	-	0.002	0.006	0.008	-	0.008
<b>Total Delivery</b>	<b>4.235</b>	<b>0.181</b>	<b>4.416</b>	<b>0.010</b>	<b>4.426</b>	<b>0.386</b>	<b>4.812</b>
<b>PNG Company Use Rate</b>							
	2.115	-	2.115	1.141	3.256	-	3.256

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Residential (RS1-LCE)</b>							
Monthly Basic Charge	\$ 8.28	\$ 0.36	\$ 8.64	\$ -	\$ 8.64	\$ 0.76	\$ 9.40
Delivery Charge	6.893	0.297	7.190	-	7.190	0.624	7.814
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	6.942	0.297	7.239	0.004	7.243	0.624	7.867
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	7.796	0.331	8.127	(1.149)	6.978	0.624	7.602
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.097	-	30.097	-	30.097	-	30.097
<b>Total</b>	<b>37.893</b>	<b>0.331</b>	<b>38.224</b>	<b>(1.149)</b>	<b>37.075</b>	<b>0.624</b>	<b>37.699</b>
<b>Small Commercial (RS2-LCE)</b>							
Monthly Basic Charge	\$ 8.29	\$ 0.36	\$ 8.65	\$ -	\$ 8.65	\$ 0.76	\$ 9.41
Delivery Charge	5.197	0.218	5.415	-	5.415	0.471	5.886
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	5.246	0.218	5.464	0.004	5.468	0.471	5.939
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	6.100	0.252	6.352	(1.149)	5.203	0.471	5.674
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.082	-	30.082	-	30.082	-	30.082
<b>Total</b>	<b>36.182</b>	<b>0.252</b>	<b>36.434</b>	<b>(1.149)</b>	<b>35.285</b>	<b>0.471</b>	<b>35.756</b>

Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Large Commercial (RS3-LCE)</b>							
Monthly Basic Charge	\$ 177.73	\$ 7.78	\$ 185.51	\$ -	\$ 185.51	\$ 16.44	\$ 201.95
Delivery Charge	3.852	0.157	4.009	-	4.009	0.348	4.357
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	3.901	0.157	4.058	0.004	4.062	0.348	4.410
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCV A Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	3.828	0.157	3.985	0.010	3.995	0.348	4.343
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCV A Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.085	-	30.085	-	30.085	-	30.085
<b>Total</b>	<b>33.913</b>	<b>0.157</b>	<b>34.070</b>	<b>0.010</b>	<b>34.080</b>	<b>0.348</b>	<b>34.428</b>
<b>Small Industrial (RS4-LCE)</b>							
Monthly Basic Charge	\$ 486.65	\$ 21.32	\$ 507.97	\$ -	\$ 507.97	\$ 45.24	\$ 553.21
Delivery Charge	2.362	0.106	2.468	-	2.468	0.217	2.685
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	2.411	0.106	2.517	0.004	2.521	0.217	2.738
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCV A Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	2.338	0.106	2.444	0.010	2.454	0.217	2.671
Gas Supply Demand	0.160	-	0.160	-	0.160	-	0.160
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.649	-	2.649	-	2.649	-	2.649
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCV A Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	29.855	-	29.855	-	29.855	-	29.855
<b>Total</b>	<b>32.193</b>	<b>0.106</b>	<b>32.299</b>	<b>0.010</b>	<b>32.309</b>	<b>0.217</b>	<b>32.526</b>

**Pacific Northern Gas (N.E.) Ltd.**  
**(Dawson Creek Division)**

**Summary of Effective and Proposed Rates**  
**(\$/GJ unless otherwise specified)**

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Residential (RS1)</b>							
Monthly Basic Charge	\$ 8.28	\$ 0.36	\$ 8.64	\$ -	\$ 8.64	\$ 0.76	\$ 9.40
Delivery Charge	6.695	0.297	6.992	-	6.992	0.638	7.630
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	6.744	0.297	7.041	0.004	7.045	0.638	7.683
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	7.598	0.331	7.929	(1.149)	6.780	0.638	7.418
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.597	-	2.597	-	2.597	-	2.597
<b>Total</b>	<b>10.195</b>	<b>0.331</b>	<b>10.526</b>	<b>(1.149)</b>	<b>9.377</b>	<b>0.638</b>	<b>10.015</b>
<b>Small Commercial (RS2)</b>							
Monthly Basic Charge	\$ 8.29	\$ 0.36	\$ 8.65	\$ -	\$ 8.65	\$ 0.76	\$ 9.41
Delivery Charge	4.660	0.218	4.878	-	4.878	0.444	5.322
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	4.709	0.218	4.927	0.004	4.931	0.444	5.375
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	5.563	0.252	5.815	(1.149)	4.666	0.444	5.110
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.582	-	2.582	-	2.582	-	2.582
<b>Total</b>	<b>8.145</b>	<b>0.252</b>	<b>8.397</b>	<b>(1.149)</b>	<b>7.248</b>	<b>0.444</b>	<b>7.692</b>
<b>Large Commercial (RS3)</b>							
Monthly Basic Charge	\$ 177.73	\$ 7.78	\$ 185.51	\$ -	\$ 185.51	\$ 16.44	\$ 201.95
Delivery Charge	3.304	0.157	3.461	-	3.461	0.314	3.775
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	3.353	0.157	3.510	0.004	3.514	0.314	3.828
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	3.280	0.157	3.437	0.010	3.447	0.314	3.761
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.585	-	2.585	-	2.585	-	2.585
<b>Total</b>	<b>5.865</b>	<b>0.157</b>	<b>6.022</b>	<b>0.010</b>	<b>6.032</b>	<b>0.314</b>	<b>6.346</b>

Pacific Northern Gas (N.E.) Ltd.  
(Dawson Creek Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Small Industrial (RS4)</b>							
Monthly Basic Charge	\$ 486.65	\$ 21.32	\$ 507.97	\$ -	\$ 507.97	\$ 45.24	\$ 553.21
Delivery Charge	2.630	0.106	2.736	-	2.736	0.251	2.987
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
Interim Rate Adjustment Rider	2.679	0.106	2.785	0.004	2.789	0.251	3.040
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
	0.002	-	0.002	0.006	0.008	-	0.008
<b>Subtotal Delivery</b>	<b>2.606</b>	<b>0.106</b>	<b>2.712</b>	<b>0.010</b>	<b>2.722</b>	<b>0.251</b>	<b>2.973</b>
Gas Supply Demand	0.160	-	0.160	-	0.160	-	0.160
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.649	-	2.649	-	2.649	-	2.649
GCVA Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
<b>Subtotal Commodity</b>	<b>2.355</b>	<b>-</b>	<b>2.355</b>	<b>-</b>	<b>2.355</b>	<b>-</b>	<b>2.355</b>
<b>Total</b>	<b>4.961</b>	<b>0.106</b>	<b>5.067</b>	<b>0.010</b>	<b>5.077</b>	<b>0.251</b>	<b>5.328</b>
<b>Small Industrial Transportation Service (RS7) (Bypass Rate)</b>							
Monthly Basic Charge	\$ 486.65	\$ 21.32	\$ 507.97	\$ -	\$ 507.97	\$ 45.24	\$ 553.21
Delivery Charge	0.2050	-	0.2050	-	0.2050	-	0.2050
Company Use	-	-	-	-	-	-	-
<b>Total Delivery</b>	<b>0.2050</b>	<b>-</b>	<b>0.2050</b>	<b>-</b>	<b>0.2050</b>	<b>-</b>	<b>0.2050</b>
<b>Commercial Transportation (RS23)</b>							
Monthly Basic Charge	\$ 147.99	\$ 6.46	\$ 154.45	\$ -	\$ 154.45	\$ 13.65	\$ 168.10
Delivery Charge	3.711	0.181	3.892	-	3.892	0.356	4.248
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
Interim Rate Adjustment Rider	3.760	0.181	3.941	0.004	3.945	0.356	4.301
GCVA Co. Use Rider	-	-	-	-	-	-	-
LCCR Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
	0.002	-	0.002	0.006	0.008	-	0.008
<b>Total Delivery</b>	<b>3.687</b>	<b>0.181</b>	<b>3.868</b>	<b>0.010</b>	<b>3.878</b>	<b>0.356</b>	<b>4.234</b>
<b>PNG Company Use Rate</b>	<b>2.115</b>	<b>-</b>	<b>2.115</b>	<b>1.141</b>	<b>3.256</b>	<b>-</b>	<b>3.256</b>

Pacific Northern Gas (N.E.) Ltd.  
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Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Residential (RS1-LCE)</b>							
Monthly Basic Charge	\$ 8.28	\$ 0.36	\$ 8.64	\$ -	\$ 8.64	\$ 0.76	\$ 9.40
Delivery Charge	6.695	0.297	6.992	-	6.992	0.638	7.630
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	6.744	0.297	7.041	0.004	7.045	0.638	7.683
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVA Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	7.598	0.331	7.929	(1.149)	6.780	0.638	7.418
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVA Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.097	-	30.097	-	30.097	-	30.097
<b>Total</b>	<b>37.695</b>	<b>0.331</b>	<b>38.026</b>	<b>(1.149)</b>	<b>36.877</b>	<b>0.638</b>	<b>37.515</b>
<b>Small Commercial (RS2-LCE)</b>							
Monthly Basic Charge	\$ 8.29	\$ 0.36	\$ 8.65	\$ -	\$ 8.65	\$ 0.76	\$ 9.41
Delivery Charge	4.660	0.218	4.878	-	4.878	0.444	5.322
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	4.709	0.218	4.927	0.004	4.931	0.444	5.375
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVA Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	0.927	0.034	0.961	(1.159)	(0.198)	-	(0.198)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	5.563	0.252	5.815	(1.149)	4.666	0.444	5.110
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVA Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.082	-	30.082	-	30.082	-	30.082
<b>Total</b>	<b>35.645</b>	<b>0.252</b>	<b>35.897</b>	<b>(1.149)</b>	<b>34.748</b>	<b>0.444</b>	<b>35.192</b>

Pacific Northern Gas (N.E.) Ltd.  
(Dawson Creek Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	<b>Interim Jan. 1'25</b>	<b>Variance Jan. 1'25 to May 1'25</b>	<b>Adjusted Interim May 1'25</b>	<b>Variance May 1'25 to Jan. 1'26</b>	<b>Adjusted Interim Jan. 1'26</b>	<b>Variance Jan. 1'26 to Mar. 1'26</b>	<b>Proposed Revised Interim Mar. 1'26</b>
<b>Large Commercial (RS3-LCE)</b>							
Monthly Basic Charge	\$ 177.73	\$ 7.78	\$ 185.51	\$ -	\$ 185.51	\$ 16.44	\$ 201.95
Delivery Charge	3.304	0.157	3.461	-	3.461	0.314	3.775
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	3.353	0.157	3.510	0.004	3.514	0.314	3.828
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	3.280	0.157	3.437	0.010	3.447	0.314	3.761
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.085	-	30.085	-	30.085	-	30.085
<b>Total</b>	<b>33.365</b>	<b>0.157</b>	<b>33.522</b>	<b>0.010</b>	<b>33.532</b>	<b>0.314</b>	<b>33.846</b>
<b>Small Industrial (RS4-LCE)</b>							
Monthly Basic Charge	\$ 486.65	\$ 21.32	\$ 507.97	\$ -	\$ 507.97	\$ 45.24	\$ 553.21
Delivery Charge	2.630	0.106	2.736	-	2.736	0.251	2.987
Company Use	0.049	-	0.049	0.004	0.053	-	0.053
	2.679	0.106	2.785	0.004	2.789	0.251	3.040
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	2.606	0.106	2.712	0.010	2.722	0.251	2.973
Gas Supply Demand	0.160	-	0.160	-	0.160	-	0.160
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.649	-	2.649	-	2.649	-	2.649
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	29.855	-	29.855	-	29.855	-	29.855
<b>Total</b>	<b>32.461</b>	<b>0.106</b>	<b>32.567</b>	<b>0.010</b>	<b>32.577</b>	<b>0.251</b>	<b>32.828</b>

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

Customer Class	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Residential (RS1)</b>							
Monthly Basic Charge	\$ 10.24	\$ (0.28)	\$ 9.96	\$ -	\$ 9.96	\$ -	\$ 9.96
Delivery Charge	13.216	(0.627)	12.589	-	12.589	(0.248)	12.341
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	13.665	(0.627)	13.038	(0.434)	12.604	(0.248)	12.356
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	1.248	(0.010)	1.238	(1.467)	(0.229)	-	(0.229)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	14.840	(0.637)	14.203	(1.895)	12.308	(0.248)	12.060
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.597	-	2.597	-	2.597	-	2.597
<b>Total</b>	<b>17.437</b>	<b>(0.637)</b>	<b>16.800</b>	<b>(1.895)</b>	<b>14.905</b>	<b>(0.248)</b>	<b>14.657</b>
<b>Small Commercial (RS2)</b>							
Monthly Basic Charge	\$ 10.27	\$ (0.29)	\$ 9.98	\$ -	\$ 9.98	\$ -	\$ 9.98
Delivery Charge	10.443	(0.482)	9.961	-	9.961	(0.178)	9.783
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	10.892	(0.482)	10.410	(0.434)	9.976	(0.178)	9.798
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	1.248	(0.010)	1.238	(1.467)	(0.229)	-	(0.229)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	12.067	(0.492)	11.575	(1.895)	9.680	(0.178)	9.502
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.582	-	2.582	-	2.582	-	2.582
<b>Total</b>	<b>14.649</b>	<b>(0.492)</b>	<b>14.157</b>	<b>(1.895)</b>	<b>12.262</b>	<b>(0.178)</b>	<b>12.084</b>
<b>Large Commercial (RS3)</b>							
Monthly Basic Charge	\$ 10.29	\$ (0.28)	\$ 10.01	\$ -	\$ 10.01	\$ -	\$ 10.01
Delivery Charge	8.581	(0.396)	8.185	-	8.185	(0.141)	8.044
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	9.030	(0.396)	8.634	(0.434)	8.200	(0.141)	8.059
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCVa Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	8.957	(0.396)	8.561	(0.428)	8.133	(0.141)	7.992
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
GCVa Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.585	-	2.585	-	2.585	-	2.585
<b>Total</b>	<b>11.542</b>	<b>(0.396)</b>	<b>11.146</b>	<b>(0.428)</b>	<b>10.718</b>	<b>(0.141)</b>	<b>10.577</b>
<b>Industrial Transport (RS5 - CNRL)</b>							
Monthly Basic Charge	\$ 11,957.07	\$ (313.81)	\$ 11,643.26	\$ -	\$ 11,643.26	\$ -	\$ 11,643.26
Delivery Charge	0.844	(0.040)	0.804	-	0.804	(0.018)	0.786
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
<b>Total Delivery</b>	<b>0.846</b>	<b>(0.040)</b>	<b>0.806</b>	<b>0.0060</b>	<b>0.812</b>	<b>(0.0180)</b>	<b>0.794</b>
<b>PNG Company Use Rate</b>							
	2.115	-	2.115	1.141	3.256	-	3.256

Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)

Summary of Effective and Proposed Rates  
(\$/GJ unless otherwise specified)

<b>LOW CARBON ENERGY RATES</b>	Interim Jan. 1'25	Variance Jan. 1'25 to May 1'25	Adjusted Interim May 1'25	Variance May 1'25 to Jan. 1'26	Adjusted Interim Jan. 1'26	Variance Jan. 1'26 to Mar. 1'26	Proposed Revised Interim Mar. 1'26
<b>Residential (RS1-LCE)</b>							
Monthly Basic Charge	\$ 10.24	\$ (0.28)	\$ 9.96	\$ -	\$ 9.96	\$ -	\$ 9.96
Delivery Charge	13.216	(0.627)	12.589	-	12.589	(0.248)	12.341
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	13.665	(0.627)	13.038	(0.434)	12.604	(0.248)	12.356
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCV A Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	1.248	(0.010)	1.238	(1.467)	(0.229)	-	(0.229)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	14.840	(0.637)	14.203	(1.895)	12.308	(0.248)	12.060
Gas Supply Demand	0.402	-	0.402	-	0.402	-	0.402
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.891	-	2.891	-	2.891	-	2.891
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
	30.391	-	30.391	-	30.391	-	30.391
GCV A Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.097	-	30.097	-	30.097	-	30.097
<b>Total</b>	<b>44.937</b>	<b>(0.637)</b>	<b>44.300</b>	<b>(1.895)</b>	<b>42.405</b>	<b>(0.248)</b>	<b>42.157</b>
<b>Small Commercial (RS2-LCE)</b>							
Monthly Basic Charge	\$ 10.27	\$ (0.29)	\$ 9.98	\$ -	\$ 9.98	\$ -	\$ 9.98
Delivery Charge	10.443	(0.482)	9.961	-	9.961	(0.178)	9.783
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	10.892	(0.482)	10.410	(0.434)	9.976	(0.178)	9.798
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCV A Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
RSAM	1.248	(0.010)	1.238	(1.467)	(0.229)	-	(0.229)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	12.067	(0.492)	11.575	(1.895)	9.680	(0.178)	9.502
Gas Supply Demand	0.387	-	0.387	-	0.387	-	0.387
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.876	-	2.876	-	2.876	-	2.876
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
	30.376	-	30.376	-	30.376	-	30.376
GCV A Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.082	-	30.082	-	30.082	-	30.082
<b>Total</b>	<b>42.149</b>	<b>(0.492)</b>	<b>41.657</b>	<b>(1.895)</b>	<b>39.762</b>	<b>(0.178)</b>	<b>39.584</b>
<b>Large Commercial (RS3-LCE)</b>							
Monthly Basic Charge	\$ 10.29	\$ (0.28)	\$ 10.01	\$ -	\$ 10.01	\$ -	\$ 10.01
Delivery Charge	8.581	(0.396)	8.185	-	8.185	(0.141)	8.044
Company Use	0.449	-	0.449	(0.434)	0.015	-	0.015
	9.030	(0.396)	8.634	(0.434)	8.200	(0.141)	8.059
Interim Rate Adjustment Rider	-	-	-	-	-	-	-
GCV A Co. Use Rider	(0.075)	-	(0.075)	-	(0.075)	-	(0.075)
LCCR Rider	0.002	-	0.002	0.006	0.008	-	0.008
Subtotal Delivery	8.957	(0.396)	8.561	(0.428)	8.133	(0.141)	7.992
Gas Supply Demand	0.390	-	0.390	-	0.390	-	0.390
Gas Supply Commodity	2.489	-	2.489	-	2.489	-	2.489
	2.879	-	2.879	-	2.879	-	2.879
Low Carbon Commodity Charge	27.500	-	27.500	-	27.500	-	27.500
	30.379	-	30.379	-	30.379	-	30.379
GCV A Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	30.085	-	30.085	-	30.085	-	30.085
<b>Total</b>	<b>39.042</b>	<b>(0.396)</b>	<b>38.646</b>	<b>(0.428)</b>	<b>38.218</b>	<b>(0.141)</b>	<b>38.077</b>

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit E – Other Regulatory Schedules**

**Provisional Decision**  
**Tab 1**  
**PNG-West**  
**2025-2027 Rate App.**  
**Test Years 2025-2027**  
**Page 1**

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020
1	Energy sales (TJ)	3,115	2,755	2,576	3,657	2,400	2,628	3,065	3,162	2,751
2	Average rate per GJ	\$24.94	\$22.78	\$20.27	\$17.34	\$21.66	\$19.54	\$18.23	\$14.39	\$13.91
3	Transportation service (TJ)	2,635	2,675	2,679	2,433	2,624	2,149	1,908	1,982	2,370
4	Average rate per GJ	\$7.99	\$6.80	\$5.82	\$5.07	\$4.60	\$7.03	\$5.38	\$4.60	\$4.35
5	Total deliveries (TJ)	5,751	5,431	5,255	6,090	5,024	4,777	4,973	5,144	5,121
6	Utility revenue									
7	Energy sales	\$67,953	\$54,855	\$45,538	\$58,725	\$51,988	\$51,367	\$55,867	\$45,487	\$38,266
8	Interim rates - sales	9,727	7,907	6,693	4,694	-	-	-	-	-
9	Transportation service	17,973	15,524	13,294	11,078	12,079	15,100	10,264	9,119	10,300
10	Interim rates - transportation	3,086	2,666	2,283	1,257	-	-	-	-	-
11	Total Utility Revenue	98,739	80,952	67,807	75,754	64,066	66,467	66,132	54,605	48,566
12	Cost of sales	11,305	8,809	6,563	17,371	5,951	10,806	17,765	12,266	7,216
13	Gross margin	87,434	72,143	61,244	58,382	58,115	55,661	48,366	42,339	41,350
14	Operating expenses	15,029	13,983	13,551	14,020	14,290	14,131	13,838	13,431	11,814
15	Maintenance expenses	941	734	871	787	516	460	333	484	492
16	Admin. & general expenses	10,595	11,278	11,121	10,752	11,480	11,285	10,847	9,112	8,807
17	Property taxes	5,111	5,022	4,935	4,645	4,645	4,447	4,275	4,120	4,047
18	Depreciation	13,182	12,183	10,716	10,592	10,335	8,702	6,630	5,488	4,756
19	Amortization on gross deferrals	(3,693)	3,425	13,435	(10,303)	(10,302)	(131)	(1,524)	(412)	(467)
20	Investment income, other revenue & credits	(251)	(251)	(251)	(209)	(4,136)	(2,552)	(174)	(247)	(277)
21	Rate smoothing deferral	7,516	(11,311)	(25,085)	-	-	-	-	(1,298)	1,269
22	LVIDA additions	-	-	-	-	-	-	873	-	-
23	Integrity cost of service deferral additions	-	-	-	(2,000)	(2,000)	(1,000)	-	-	-
24		48,430	35,062	29,293	28,283	24,828	35,341	35,098	30,679	30,441
25	Earned return before income taxes	39,004	37,081	31,951	30,099	33,287	20,320	13,267	11,660	10,908
26	Future Income taxes on Deferrals	(310)	(87)	(3,093)	3,680	3,679	411	748	505	384
27	Income taxes	6,778	5,759	4,987	(1,025)	76	(3,248)	(2,967)	781	(65)
28	Earned return	\$32,536	\$31,409	\$30,057	\$27,444	\$29,532	\$23,157	\$15,486	\$10,374	\$10,589
29	Utility rate base	\$418,213	\$401,243	\$375,114	\$368,855	\$350,814	\$310,967	\$239,795	\$171,954	\$150,654
30	Return on rate base	7.78%	7.83%	8.01%	7.44%	8.42%	7.45%	6.46%	6.03%	7.03%

**Provisional Decision**  
**Tab 2**  
**PNG-West**  
**2025-2027 Rate App.**  
**Test Years 2025-2027**  
**Page 1**

**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020
1	Plant in service beginning of year	\$648,693	\$611,310	\$565,064	\$547,393	\$541,724	\$473,535	\$380,295	\$326,969	\$312,320
2	Additions	14,149	37,609	46,554	47,974	26,708	69,055	93,738	58,524	15,812
3	Disposals (at cost)	-	(227)	(308)	(637)	(3,368)	(866)	(498)	(5,198)	(1,163)
4	Plant in service end of year	662,841	648,693	611,310	594,730	565,064	541,724	473,535	380,295	326,969
5	Accumulated depreciation	231,062	217,305	204,685	196,507	193,620	185,773	177,086	170,410	167,300
6	Net plant in service end of year	431,779	431,387	406,625	398,223	371,444	355,950	296,450	209,885	159,669
7	Net plant beginning of year	431,476	406,625	371,444	361,423	355,950	296,450	209,885	159,668	149,285
8	Net plant in service midyear	431,627	419,006	389,034	379,823	363,697	326,200	253,167	184,777	154,477
9	Adjustment - expenditure/disposal timing	(723)	(5,398)	(2,140)	(3,304)	(3,304)	(7,303)	(11,016)	(11,922)	(3,065)
10	Contributions in aid of construction	(15,195)	(15,580)	(15,964)	(14,065)	(15,692)	(12,881)	(12,634)	(11,066)	(10,942)
11	Pension funding in excess of expense	7,117	6,235	5,366	5,020	4,653	4,031	3,703	4,008	4,282
12	Non-pension post retirement credit	-	-	-	-	-	-	-	-	-
13	Deferred income taxes	-	-	-	-	-	-	-	-	-
14	Work in progress, no AFUDC	100	100	100	100	100	100	100	100	100
15	Unamortized deferred charges	(11,281)	(9,106)	(6,744)	(4,326)	(4,418)	(2,359)	(188)	663	790
16	Cash working capital	2,721	2,591	2,551	2,477	1,401	1,298	2,143	2,646	2,223
17	Other working capital	3,846	3,395	2,911	3,130	4,377	1,880	4,520	2,748	2,789
18	Utility rate base, midyear	<u>\$418,212</u>	<u>\$401,243</u>	<u>\$375,114</u>	<u>\$368,855</u>	<u>\$350,814</u>	<u>\$310,967</u>	<u>\$239,795</u>	<u>\$171,954</u>	<u>\$150,654</u>



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**Pacific Northern Gas Ltd.  
(PNG-West Division)**

**COMMON EQUITY**

**SCHEDULE 4  
(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020
1	Opening balance									
2	Share capital	\$117,465	\$117,465	\$109,465	\$78,465	\$79,465	\$68,465	\$33,465	\$13,465	\$13,465
3	Contributed surplus	3,555	3,555	3,555	3,555	3,555	3,555	3,555	3,555	3,555
4	Retained earnings	174,281	158,168	136,635	121,620	120,459	109,109	101,600	96,082	91,508
5		295,302	279,189	249,656	203,641	203,479	181,130	138,620	113,103	108,528
6	Net income	29,796	28,113	26,306	19,408	22,404	17,325	13,534	11,518	10,515
7	Shares issued (redeemed), contributed surplus	-	-	8,000	9,000	30,000	11,000	35,000	20,000	-
8	Preferred dividends	-	-	-	-	-	-	-	-	-
9	Common dividends	(28,000)	(12,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)
10	Closing balance	\$297,098	\$295,302	\$277,961	\$226,049	\$249,883	\$203,455	\$181,155	\$138,620	\$113,043
11	Midyear common equity	\$296,200	\$287,245	\$263,809	\$214,845	\$226,681	\$192,292	\$159,888	\$125,862	\$110,786
12	Investment in Non Utility	-	-	-	-	-	-	-	-	-
13	less: acquisition premiums	(184)	(184)	(184)	(184)	(184)	(206)	(217)	(228)	(315)
14	less: investment in subsidiary utility	(25,643)	(24,771)	(23,272)	(20,490)	(22,992)	(19,633)	(20,549)	(18,260)	(16,956)
15		\$270,372	\$262,289	\$240,352	\$194,170	\$203,505	\$172,453	\$139,122	\$107,373	\$93,515
16	Deemed utility common equity	\$217,470	\$208,647	\$195,059	\$171,517	\$203,505	\$172,453	\$139,122	\$107,373	\$93,516
17	Unused equity	\$52,901	\$53,643	\$45,293	\$22,653	\$0	\$0	\$0	\$0	(\$1)

**Provisional Decision**  
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**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020
1	Short Term Debt	\$4,195	\$4,000	\$3,763	\$3,405	(\$35,061)	(\$27,111)	(\$15,061)	(\$17,595)	(\$2,917)
2	proportion	1.00%	1.00%	1.00%	0.92%	(9.99%)	(8.72%)	(6.28%)	(10.23%)	(1.94%)
3	rate of return	3.92%	3.89%	4.23%	5.06%	(1.07%)	1.57%	2.18%	2.42%	(0.14%)
4	return component	0.04%	0.04%	0.04%	0.05%	0.11%	(0.14%)	(0.14%)	(0.25%)	0.00%
5	Long term debt	\$196,548	\$188,597	\$176,292	\$193,932	\$182,370	\$165,625	\$115,735	\$82,175	\$60,056
6	proportion	47.00%	47.00%	47.00%	52.58%	51.98%	53.26%	48.26%	47.79%	39.86%
7	rate of return	4.96%	5.07%	5.45%	5.66%	6.04%	6.00%	4.73%	4.35%	5.40%
8	return component	2.33%	2.38%	2.56%	2.98%	3.14%	3.19%	2.28%	2.08%	2.15%
9	Common equity	\$217,471	\$208,647	\$195,059	\$171,517	\$203,505	\$172,453	\$139,122	\$107,373	\$93,516
10	proportion	52.00%	52.00%	52.00%	46.50%	58.01%	55.46%	58.02%	62.44%	62.07%
11	rate of return	10.40%	10.40%	10.40%	9.50%	8.91%	7.92%	7.43%	6.73%	7.85%
12	return component	5.41%	5.41%	5.41%	4.42%	5.17%	4.39%	4.31%	4.20%	4.87%
13	Total capitalization	<u>\$418,213</u>	<u>\$401,243</u>	<u>\$375,114</u>	<u>\$368,855</u>	<u>\$350,814</u>	<u>\$310,967</u>	<u>\$239,795</u>	<u>\$171,954</u>	<u>\$150,654</u>
14	Return on rate base	<u>7.78%</u>	<u>7.83%</u>	<u>8.01%</u>	<u>7.44%</u>	<u>8.42%</u>	<u>7.45%</u>	<u>6.46%</u>	<u>6.03%</u>	<u>7.03%</u>
15	Utility rate base	<u>\$418,212</u>	<u>\$401,243</u>	<u>\$375,114</u>	<u>\$368,855</u>	<u>\$350,814</u>	<u>\$310,967</u>	<u>\$239,795</u>	<u>\$171,954</u>	<u>\$150,654</u>

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**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Energy sales (TJ)	3,242	2,888	2,631	3,657	2,400	2,628	3,065	3,162	2,751	Tab 6, page 8, 25, 42
2	Average rate per GJ	\$26.16	\$26.26	\$21.78	\$17.34	\$21.66	\$19.54	\$18.23	\$14.39	\$13.91	
3	Transportation service (TJ)	2,635	2,675	2,679	2,433	2,624	2,149	1,908	1,982	2,370	Tab 6, page 8, 25, 42
4	Average rate per GJ	\$8.58	\$8.15	\$6.38	\$5.07	\$4.60	\$7.03	\$5.38	\$4.60	\$4.35	
5	Total deliveries (TJ)	5,878	5,564	5,309	6,090	5,024	4,777	4,973	5,144	5,121	Tab 6, page 8, 25, 42
6	Utility revenue										
7	Energy sales	\$81,338	\$61,435	\$46,360	\$58,725	\$51,988	\$51,367	\$55,867	\$45,487	\$38,266	Tab 6, page 8, 25, 42
8	Interim rates - sales	3,466	14,414	10,938	4,694	-	-	-	-	-	Tab 6, page 7, 24, 41
9	Transportation service	21,551	17,097	13,401	11,078	12,079	15,100	10,264	9,119	10,300	Tab 6, page 7, 24, 41
10	Interim rates - transportation	1,073	4,720	3,694	1,257	-	-	-	-	-	Tab 6, page 7, 24, 41
11	Total Utility Revenue	107,428	97,666	74,392	75,754	64,066	66,467	66,132	54,605	48,566	
12	Cost of sales	11,696	9,221	6,685	17,371	5,951	10,806	17,765	12,266	7,216	Tab 6, page 11, 28, 45
13	Gross margin	95,731	88,444	67,707	58,382	58,115	55,661	48,366	42,339	41,350	
14	Operating expenses	15,370	14,471	13,959	14,020	14,290	14,131	13,838	13,431	11,814	Tab 1, page 2, line 7
15	Maintenance expenses	941	913	871	787	516	460	333	484	492	Tab 1, page 2, line 11
16	Admin. & general expenses	12,359	11,580	11,278	10,752	11,480	11,285	10,847	9,112	8,807	Tab 1, page 2, line 18
17	Property taxes	5,111	5,022	4,935	4,645	4,645	4,447	4,275	4,120	4,047	Tab 1, page 8, line 4
18	Depreciation	13,920	12,287	10,716	10,592	10,335	8,702	6,630	5,488	4,756	Tab 2, page 9, 10 & 11, line 40
19	Amortization on gross deferrals	3,097	3,425	7,654	(10,303)	(10,302)	(131)	(1,524)	(412)	(467)	Tab 2, page 21, 22 & 23, lines 41, 42
20	Investment income, other revenue & credits	(251)	(251)	(251)	(209)	(4,136)	(2,552)	(174)	(247)	(277)	Tab 1, page 9, line 6
21	Rate smoothing deferral	6,859	5,985	(12,036)	-	-	-	-	(1,298)	1,269	Tab 2, page 21, 22 & 23, lines 15, 16
22	LVIDA additons	-	-	-	-	-	-	873	-	-	
23	Integrity cost of service deferral additions	-	-	-	(2,000)	(2,000)	(1,000)	-	-	-	Tab 2, page 19 & 20, lines 33, 35
24		57,405	53,431	37,125	28,283	24,828	35,341	35,098	30,679	30,441	
25	Earned return before income taxes	38,326	35,013	30,582	30,099	33,287	20,320	13,267	11,660	10,908	
26	Future Income taxes on Deferrals	(1,961)	(1,703)	(1,532)	3,680	3,679	411	748	505	384	Tab 2, page 21, 22 & 23, lines 42, 43
27	Income taxes	6,129	4,960	2,069	(1,025)	76	(3,248)	(2,967)	781	(65)	Tab 3, page 1, line 11
28	Earned return	\$34,158	\$31,756	\$30,045	\$27,444	\$29,532	\$23,157	\$15,486	\$10,374	\$10,589	
29	Utility rate base	\$441,943	\$406,598	\$375,376	\$368,855	\$350,814	\$310,967	\$239,795	\$171,954	\$150,654	Tab 2, page 1, line 18
30	Return on rate base	7.73%	7.81%	8.00%	7.44%	8.42%	7.45%	6.46%	6.03%	7.03%	Tab 5, page 1, line 14

**2025-2027 RRA**  
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**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Plant in service beginning of year	\$663,100	\$612,451	\$565,064	\$547,393	\$541,724	\$473,535	\$380,295	\$326,969	\$312,320	Tab 2, page 4, 5 & 6, line 46
2	Additions	38,502	50,875	47,695	47,974	26,708	69,055	93,738	58,524	15,812	Tab 2, page 4, 5 & 6, line 46
3	Disposals (at cost)	-	(227)	(308)	(637)	(3,368)	(866)	(498)	(5,198)	(1,163)	Tab 2, page 4, 5 & 6, line 46
4	Plant in service end of year	701,602	663,100	612,451	594,730	565,064	541,724	473,535	380,295	326,969	
5	Accumulated depreciation	232,004	217,412	204,685	196,507	193,620	185,773	177,086	170,410	167,300	Tab 2, page 13, line 17
6	Net plant in service end of year	469,598	445,688	407,766	398,223	371,444	355,950	296,450	209,885	159,669	
7	Net plant beginning of year	445,688	407,766	371,444	361,423	355,950	296,450	209,885	159,668	149,285	Tab 2, page 12 & 13, net of lines 1 & 1
8	Net plant in service midyear	457,643	426,727	389,605	379,823	363,697	326,200	253,167	184,777	154,477	
9	Adjustment - expenditure/disposal timing	(3,194)	(7,606)	(2,106)	(3,304)	(3,304)	(7,303)	(11,016)	(11,922)	(3,065)	Tab 2, page 14, line 17
10	Contributions in aid of construction	(15,188)	(15,579)	(15,964)	(14,065)	(15,692)	(12,881)	(12,634)	(11,066)	(10,942)	Tab 2, page 16, line 11
11	Pension funding in excess of expense	7,117	6,235	5,366	5,020	4,653	4,031	3,703	4,008	4,282	Tab 2, page 17, line 16
12	Non-pension post retirement credit	-	-	-	-	-	-	-	-	-	Tab 2, page 18, line 7
13	Deferred income taxes	-	-	-	-	-	-	-	-	-	Tab 2, page 15, line 5
14	Work in progress, no AFUDC	100	100	100	100	100	100	100	100	100	Tab 2, page 21, 22 & 23, line 10
15	Unamortized deferred charges	(11,291)	(9,107)	(6,744)	(4,326)	(4,418)	(2,359)	(188)	663	790	Tab 2, page 24, 31 & 38, line 11
16	Cash working capital	2,895	2,426	2,208	2,477	1,401	1,298	2,143	2,646	2,223	Tab 2, page 30 & 37 & 44, line 15
17	Other working capital	3,861	3,402	2,912	3,130	4,377	1,880	4,520	2,748	2,789	
18	Utility rate base, midyear	\$441,943	\$406,598	\$375,376	\$368,855	\$350,814	\$310,967	\$239,795	\$171,954	\$150,654	



**2025-2027 RRA**  
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**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Opening balance										
2	Share capital	\$113,465	\$113,465	\$109,465	\$78,465	\$79,465	\$68,465	\$33,465	\$13,465	\$13,465	
3	Contributed surplus	3,555	3,555	3,555	3,555	3,555	3,555	3,555	3,555	3,555	
4	Retained earnings	173,627	157,967	136,635	121,620	120,459	109,109	101,600	96,082	91,508	
5		290,647	274,987	249,656	203,641	203,479	181,130	138,620	113,103	108,528	
6	Net income	29,810	27,653	26,104	19,408	22,404	17,325	13,534	11,518	10,515	
7	Shares issued (redeemed), contributed surplus	-	-	4,000	9,000	30,000	11,000	35,000	20,000	-	
8	Preferred dividends	-	-	-	-	-	-	-	-	-	
9	Common dividends	(16,000)	(12,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	(6,000)	
10	Closing balance	\$304,458	\$290,641	\$273,760	\$226,049	\$249,883	\$203,455	\$181,155	\$138,620	\$113,043	
11	Midyear common equity	\$297,552	\$282,814	\$261,708	\$214,845	\$226,681	\$192,292	\$159,888	\$125,862	\$110,786	
12	Investment in Non Utility	-	-	-	-	-	-	-	-	-	
13	less: acquisition premiums	(184)	(184)	(184)	(184)	(184)	(206)	(217)	(228)	(315)	
14	less: investment in subsidiary utility	(27,155)	(25,298)	(23,429)	(20,490)	(22,992)	(19,633)	(20,549)	(18,260)	(16,956)	
15		\$270,213	\$257,331	\$238,094	\$194,170	\$203,505	\$172,453	\$139,122	\$107,373	\$93,515	
16	Deemed utility common equity	\$229,810	\$211,431	\$195,196	\$171,517	\$203,505	\$172,453	\$139,122	\$107,373	\$93,516	Tab 5, page 1, line 9
17	Unused equity	\$40,403	\$45,900	\$42,898	\$22,653	\$0	\$0	\$0	\$0	(\$1)	

**2025-2027 RRA**  
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**PNG-West**  
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**Pacific Northern Gas Ltd.**  
**(PNG-West Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Short Term Debt	\$4,422	\$4,073	\$3,762	\$3,405	(\$35,061)	(\$27,111)	(\$15,061)	(\$17,595)	(\$2,917)	
2	proportion	1.00%	1.00%	1.00%	0.92%	(9.99%)	(8.72%)	(6.28%)	(10.23%)	(1.94%)	
3	rate of return	3.95%	3.91%	4.22%	5.06%	(1.07%)	1.57%	2.18%	2.42%	(0.14%)	Tab 5, page 2, line 10
4	return component	0.04%	0.04%	0.04%	0.05%	0.11%	(0.14%)	(0.14%)	(0.25%)	0.00%	
5	Long term debt	\$207,710	\$191,094	\$176,418	\$193,932	\$182,370	\$165,625	\$115,735	\$82,175	\$60,056	Tab 5, page 4, line 106
6	proportion	47.00%	47.00%	47.00%	52.58%	51.98%	53.26%	48.26%	47.79%	39.86%	
7	rate of return	4.85%	5.03%	5.43%	5.66%	6.04%	6.00%	4.73%	4.35%	5.40%	Tab 5, page 4, line 107
8	return component	2.28%	2.36%	2.55%	2.98%	3.14%	3.19%	2.28%	2.08%	2.15%	
9	Common equity	\$229,810	\$211,431	\$195,196	\$171,517	\$203,505	\$172,453	\$139,122	\$107,373	\$93,516	
10	proportion	52.00%	52.00%	52.00%	46.50%	58.01%	55.46%	58.02%	62.44%	62.07%	
11	rate of return	10.40%	10.40%	10.40%	9.50%	8.91%	7.92%	7.43%	6.73%	7.85%	
12	return component	5.41%	5.41%	5.41%	4.42%	5.17%	4.39%	4.31%	4.20%	4.87%	
13	Total capitalization	\$441,943	\$406,598	\$375,376	\$368,855	\$350,814	\$310,967	\$239,795	\$171,954	\$150,654	
14	Return on rate base	7.73%	7.81%	8.00%	7.44%	8.42%	7.45%	6.46%	6.03%	7.03%	
15	Utility rate base	\$441,943	\$406,598	\$375,376	\$368,855	\$350,814	\$310,967	\$239,795	\$171,954	\$150,654	Tab 2, page 1, line 18

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**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1  
(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Energy sales (TJ)	3,580	3,607	3,644	3,879	3,829	3,359	4,079	3,799	3,930	Tab 6, page 8, 25 & 42
2	Average rate per GJ	\$11.21	\$10.38	\$8.91	\$10.47	\$8.46	\$10.06	\$10.43	\$8.41	\$6.66	
3	Transportation service (TJ)	1,401	1,401	1,396	1,450	591	709	692	508	770	Tab 6, page 8, 25 & 42
4	Average rate per GJ	\$1.22	\$1.12	\$1.04	\$1.02	\$2.20	\$1.72	\$1.88	\$2.13	\$1.34	
5	Total deliveries (TJ)	4,981	5,008	5,040	5,329	4,420	4,068	4,771	4,307	4,700	Tab 6, page 8, 25 & 42
6	Utility revenue										
7	Energy sales	\$37,954	\$35,445	\$30,598	\$39,228	\$32,378	\$33,802	\$42,548	\$31,953	\$26,180	Tab 6, page 9, 26 & 43
8	Interim rates - sales	2,170	2,008	1,864	1,377	-	-	-	-	-	Tab 6, page 8, 25 & 42
9	Transportation service	1,574	1,463	1,347	1,398	1,302	1,220	1,298	1,083	1,034	Tab 6, page 9, 26 & 43
10	Interim rates - transportation	138	110	100	77	-	-	-	-	-	Tab 6, page 8, 25 & 42
11	Total Utility Revenue	41,835	39,027	33,908	42,080	33,680	35,022	43,846	33,036	27,213	
12	Cost of sales	13,181	12,511	9,325	17,801	9,530	12,309	22,283	13,342	8,490	Tab 6, page 12, 29 & 46
13	Gross margin	28,654	26,516	24,583	24,278	24,149	22,712	21,563	19,693	18,723	
14	Operating expenses	7,518	7,431	7,120	6,971	7,211	6,770	7,097	7,027	6,485	Tab 1, page 2, line 6
15	Maintenance expenses	636	618	588	546	668	488	470	379	397	Tab 1, page 2, line 10
16	Admin. & general expenses	3,822	3,789	3,725	3,519	3,545	3,487	3,734	2,995	3,005	Tab 1, page 2, line 16
17	Property taxes	1,699	1,670	1,642	1,534	1,534	1,470	1,473	1,417	1,392	Tab 1, page 7, line 4
18	Depreciation	3,380	3,188	2,897	2,881	2,839	2,816	2,724	2,334	2,079	Tab 2, page 10, 11 & 12, line 41
19	Amortization on gross deferrals	1,193	1,203	2,463	1,323	1,326	1,252	282	927	853	Tab 2, page 16, 17 & 18, line 33
20	Investment income, other revenue	(200)	(200)	(200)	(252)	(1,195)	(62)	(140)	(251)	(248)	Tab 1, page 8, line 5
21	Rate smoothing deferral	1,659	215	(1,730)	562	522	(490)	-	113	(110)	Tab 2, page 16, 17 & 18, line 18
22	Interim to permanent rate adjustment	-	-	-	-	-	-	-	-	474	
23		19,708	17,915	16,506	17,083	16,449	15,732	15,640	14,941	14,327	
24	Earned return before income taxes	8,946	8,601	8,077	7,195	7,700	6,980	5,923	4,752	4,396	
25	Future Income taxes on deferrals	(514)	(121)	(407)	(244)	180	(56)	141	(82)	(139)	Tab 2, page 16, 17 & 18, line 34
26	Income taxes	2,048	1,595	1,742	1,281	1,078	1,138	626	262	234	Tab 3, page 1, line 11
27	Earned return	7,412	7,127	6,741	6,158	6,817	5,898	5,156	4,573	4,301	
28	Utility rate base	\$101,416	\$97,922	\$92,151	\$92,559	\$87,780	\$88,549	\$89,802	\$84,384	\$76,750	Tab 2, page 1, line 18
29	Return on rate base	7.31%	7.28%	7.32%	6.65%	7.77%	6.66%	5.74%	5.42%	5.60%	Tab 5, page 1, line 18

**Provisional Decision  
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**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**UTILITY RATE BASE**

**SCHEDULE 2  
(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Plant in service beginning of year	\$167,841	\$160,696	\$149,939	\$148,886	\$147,249	\$144,247	\$140,568	\$128,739	\$121,892	Tab 2, page 4, 5 & 6, line 42
2	Additions	6,782	7,316	10,831	6,078	3,701	3,388	3,973	12,240	7,258	Tab 2, page 4, 5 & 6, line 42
3	Disposals	(44)	(171)	(74)	(50)	(1,010)	(386)	(294)	(411)	(411)	Tab 2, page 4, 5 & 6, line 42
4	Plant in service end of year	174,579	167,841	160,696	154,913	149,939	147,249	144,247	140,568	128,739	
5	Accumulated depreciation	63,460	59,732	56,322	54,184	53,108	50,775	47,847	44,996	42,633	Tab 2, page 10, 11 & 12 line 38
6	Net plant in service end of year	111,119	108,109	104,374	100,729	96,831	96,474	96,400	95,572	86,107	
7	Net plant beginning of year	108,109	104,374	96,831	97,905	96,474	96,400	95,572	86,107	81,361	Tab 2, pages 7 & 13, net of lines 1 & 1
8	Net plant in service midyear	109,614	106,241	100,602	99,317	96,652	96,437	95,986	90,839	83,734	
9	Contributions for construction	(9,293)	(9,462)	(9,630)	(9,425)	(9,736)	(9,729)	(9,716)	(9,819)	(9,922)	Tab 2, page 40, line 13
10	Tomslake net plant disallowance	(41)	(43)	(44)	(45)	(45)	(46)	(47)	(47)	(48)	Tab 2, page 41, line 5
11	Unamortized deferred charges	(3,877)	(3,112)	(2,378)	(1,691)	(1,738)	(1,220)	(614)	(134)	269	Tab 2, page 16, 17 & 18, line 10
12	Deferred income taxes	-	-	-	-	-	-	-	-	-	Tab 2, page 44, line 8
13	Reserve for damages	-	-	-	-	-	-	-	-	-	
14	Pension funding in excess of expense	2,089	1,906	1,726	1,599	1,529	1,300	1,140	1,096	1,094	Tab 2, page 42, line 11
15	Non-pension post retirement	-	-	-	-	-	-	-	-	-	Tab 2, page 43, line 17
16	Cash working capital	1,269	1,218	1,173	1,336	775	893	1,363	1,448	1,038	Tab 2, page 19, 26 & 33, line 10
17	Other working capital	1,655	1,174	702	1,468	343	914	1,690	1,001	585	Tab 2, page 25, 32 & 39, line 15
18	Utility rate base, midyear	\$101,416	\$97,922	\$92,151	\$92,559	\$87,780	\$88,549	\$89,802	\$84,384	\$76,750	



**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Opening balance										
2	Share capital	\$12,195	\$12,195	\$12,195	\$12,195	\$12,195	\$12,195	\$9,595	\$9,595	\$9,595	
3	Contributed surplus	-	-	-	-	-	-	-	-	-	
4	Retained earnings	37,715	27,983	32,458	28,533	28,312	28,714	25,630	22,669	20,847	
5		49,910	40,178	44,653	40,728	40,508	40,909	35,225	32,264	30,442	
6	Net income	4,851	4,685	4,409	3,511	4,145	3,610	3,085	2,961	2,822	
7	Shares issued	-	-	-	-	-	-	2,600	-	-	
8	Preferred dividends	-	-	-	-	-	-	-	-	-	
9	Common dividends	(11,370)	5,047	(8,935)	(9,068)	-	(4,012)	-	-	(1,000)	
10	Closing balance	\$43,392	\$49,910	\$40,126	\$35,171	\$44,653	\$40,508	\$40,909	\$35,225	\$32,264	
11	Midyear common equity	\$46,651	\$45,044	\$42,389	\$37,949	\$42,580	\$40,708	\$38,067	\$33,744	\$31,353	Tab 5, page 1, line 13

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**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5  
(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Short term borrowings	\$1,011	\$979	\$553	\$400	(\$9,994)	(\$4,753)	\$4,167	\$8,891	\$1,771	
2	proportion	1.00%	1.00%	0.60%	0.43%	(11.39%)	(5.37%)	4.64%	10.54%	2.31%	
3	rate of return	2.27%	2.26%	1.13%	12.57%	(0.46%)	1.64%	3.36%	3.06%	2.57%	Tab 5, page 2, line 10
4	return component	0.02%	0.02%	0.01%	0.05%	0.05%	(0.09%)	0.16%	0.32%	0.06%	
5	Long term debt	\$53,754	\$51,899	\$49,209	\$54,211	\$55,195	\$52,594	\$47,568	\$41,749	\$43,626	Tab 5, page 4, line 78
6	proportion	53.00%	53.00%	53.40%	58.57%	62.88%	59.39%	52.97%	49.48%	56.84%	
7	rate of return	4.72%	4.66%	4.73%	4.79%	4.77%	4.73%	3.90%	3.63%	3.47%	Tab 5, page 4, line 79
8	return component	2.50%	2.47%	2.52%	2.81%	3.00%	2.81%	2.07%	1.79%	1.97%	
9	Preferred shares	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
10	proportion	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	rate of return	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	
12	return component	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Common equity	\$46,651	\$45,044	\$42,389	\$37,949	\$42,580	\$40,708	\$38,067	\$33,744	\$31,353	
14	proportion	46.00%	46.00%	46.00%	41.00%	48.51%	45.97%	42.39%	39.99%	40.85%	
15	rate of return	10.40%	10.40%	10.40%	9.25%	9.71%	9.21%	8.30%	8.26%	8.75%	
16	return component	4.78%	4.78%	4.78%	3.79%	4.71%	4.23%	3.52%	3.30%	3.58%	
17	Total capitalization	<u>\$101,416</u>	<u>\$97,922</u>	<u>\$92,151</u>	<u>\$92,559</u>	<u>\$87,780</u>	<u>\$88,549</u>	<u>\$89,802</u>	<u>\$84,384</u>	<u>\$76,750</u>	
18	Return on rate base	<u>7.31%</u>	<u>7.28%</u>	<u>7.32%</u>	<u>6.65%</u>	<u>7.77%</u>	<u>6.95%</u>	<u>5.74%</u>	<u>5.42%</u>	<u>5.60%</u>	
19	Utility rate base	<u>\$101,416</u>	<u>\$97,922</u>	<u>\$92,151</u>	<u>\$92,559</u>	<u>\$87,780</u>	<u>\$88,549</u>	<u>\$89,802</u>	<u>\$84,384</u>	<u>\$76,750</u>	Tab 2, page 1, line 18

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**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Energy sales (TJ)	3,631	3,650	3,679	3,879	3,829	3,359	4,079	3,799	3,930	Tab 6, page 8, 25 & 42
2	Average rate per GJ	\$11.18	\$10.34	\$8.88	\$10.47	\$8.46	\$10.06	\$10.43	\$8.41	\$6.66	
3	Transportation service (TJ)	1,401	1,401	1,396	1,450	591	709	692	508	770	Tab 6, page 8, 25 & 42
4	Average rate per GJ	\$1.24	\$1.14	\$1.04	\$1.02	\$2.20	\$1.72	\$1.88	\$2.13	\$1.34	
5	Total deliveries (TJ)	5,032	5,051	5,074	5,329	4,420	4,068	4,771	4,307	4,700	Tab 6, page 8, 25 & 42
6	Utility revenue										
7	Energy sales	\$38,406	\$35,734	\$30,808	\$39,228	\$32,378	\$33,802	\$42,548	\$31,953	\$26,180	Tab 6, page 9, 26 & 43
8	Interim rates - sales	2,192	2,024	1,874	1,377	-	-	-	-	-	Tab 6, page 8, 25 & 42
9	Transportation service	1,597	1,468	1,349	1,398	1,302	1,220	1,298	1,083	1,034	Tab 6, page 9, 26 & 43
10	Interim rates - transportation	140	128	100	77	-	-	-	-	-	Tab 6, page 8, 25 & 42
11	Total Utility Revenue	42,334	39,354	34,131	42,080	33,680	35,022	43,846	33,036	27,213	
12	Cost of sales	13,337	12,589	9,389	17,801	9,530	12,309	22,283	13,342	8,490	Tab 6, page 12, 29 & 46
13	Gross margin	28,997	26,765	24,742	24,278	24,149	22,712	21,563	19,693	18,723	
14	Operating expenses	7,611	7,512	7,146	6,971	7,211	6,770	7,097	7,027	6,485	Tab 1, page 2, line 6
15	Maintenance expenses	636	618	588	546	668	488	470	379	397	Tab 1, page 2, line 10
16	Admin. & general expenses	3,861	3,811	3,773	3,519	3,545	3,487	3,734	2,995	3,005	Tab 1, page 2, line 16
17	Property taxes	1,699	1,670	1,642	1,534	1,534	1,470	1,473	1,417	1,392	Tab 1, page 7, line 4
18	Depreciation	3,416	3,206	2,897	2,881	2,839	2,816	2,724	2,334	2,079	Tab 2, page 10, 11 & 12, line 41
19	Amortization on gross deferrals	1,198	1,206	2,466	1,323	1,326	1,252	282	927	853	Tab 2, page 16, 17 & 18, line 33
20	Investment income, other revenue	(200)	(200)	(200)	(252)	(1,195)	(62)	(140)	(251)	(248)	Tab 1, page 8, line 5
21	Rate smoothing deferral	1,575	233	(1,670)	562	522	(490)	-	113	(110)	Tab 2, page 16, 17 & 18, line 18
22	Interim to permanent rate adjustment	-	-	-	-	-	-	-	-	474	
23		19,798	18,056	16,642	17,083	16,449	15,732	15,640	14,941	14,327	
24	Earned return before income taxes	9,199	8,709	8,100	7,195	7,700	6,980	5,923	4,752	4,396	
25	Future Income taxes on deferrals	(492)	(126)	(408)	(244)	180	(56)	141	(82)	(139)	Tab 2, page 16, 17 & 18, line 34
26	Income taxes	1,890	1,581	1,726	1,281	1,078	1,138	626	262	234	Tab 3, page 1, line 11
27	Earned return	7,801	7,253	6,782	6,158	6,817	5,898	5,156	4,573	4,301	
28	Utility rate base	\$107,337	\$99,819	\$92,715	\$92,559	\$87,780	\$88,549	\$89,802	\$84,384	\$76,750	Tab 2, page 1, line 18
29	Return on rate base	7.27%	7.27%	7.31%	6.65%	7.77%	6.66%	5.74%	5.42%	5.60%	Tab 5, page 1, line 18

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**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**UTILITY RATE BASE**

**SCHEDULE 2  
(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Plant in service beginning of year	\$170,142	\$161,920	\$149,939	\$148,886	\$147,249	\$144,247	\$140,568	\$128,739	\$121,892	Tab 2, page 4, 5 & 6, line 42
2	Additions	13,770	8,394	12,054	6,078	3,701	3,388	3,973	12,240	7,258	Tab 2, page 4, 5 & 6, line 42
3	Disposals	(44)	(171)	(74)	(50)	(1,010)	(386)	(294)	(411)	(411)	Tab 2, page 4, 5 & 6, line 42
4	Plant in service end of year	183,869	170,142	161,920	154,913	149,939	147,249	144,247	140,568	128,739	
5	Accumulated depreciation	63,511	59,749	56,322	54,184	53,108	50,775	47,847	44,996	42,633	Tab 2, page 10, 11 & 12 line 38
6	Net plant in service end of year	120,357	110,393	105,597	100,729	96,831	96,474	96,400	95,572	86,107	
7	Net plant beginning of year	110,393	105,597	96,831	97,905	96,474	96,400	95,572	86,107	81,361	Tab 2, pages 7 & 13, net of lines 1 & 1
8	Net plant in service midyear	115,375	107,995	101,214	99,317	96,652	96,437	95,986	90,839	83,734	
9	Contributions for construction	(9,295)	(9,463)	(9,630)	(9,425)	(9,736)	(9,729)	(9,716)	(9,819)	(9,922)	Tab 2, page 40, line 13
10	Tomslake net plant disallowance	(41)	(43)	(44)	(45)	(45)	(46)	(47)	(47)	(48)	Tab 2, page 41, line 5
11	Unamortized deferred charges	(3,881)	(3,113)	(2,378)	(1,691)	(1,738)	(1,220)	(614)	(134)	269	Tab 2, page 16, 17 & 18, line 10
12	Deferred income taxes	-	-	-	-	-	-	-	-	-	Tab 2, page 44, line 8
13	Reserve for damages	-	-	-	-	-	-	-	-	-	
14	Pension funding in excess of expense	2,089	1,906	1,726	1,599	1,529	1,300	1,140	1,096	1,094	Tab 2, page 42, line 11
15	Non-pension post retirement	-	-	-	-	-	-	-	-	-	Tab 2, page 43, line 17
16	Cash working capital	1,435	1,362	1,125	1,336	775	893	1,363	1,448	1,038	Tab 2, page 19, 26 & 33, line 10
17	Other working capital	1,655	1,174	702	1,468	343	914	1,690	1,001	585	Tab 2, page 25, 32 & 39, line 15
18	Utility rate base, midyear	\$107,337	\$99,819	\$92,715	\$92,559	\$87,780	\$88,549	\$89,802	\$84,384	\$76,750	



**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Opening balance										
2	Share capital	\$12,195	\$12,195	\$12,195	\$12,195	\$12,195	\$12,195	\$9,595	\$9,595	\$9,595	
3	Contributed surplus	-	-	-	-	-	-	-	-	-	
4	Retained earnings	38,922	28,521	32,458	28,533	28,312	28,714	25,630	22,669	20,847	
5		51,117	40,716	44,653	40,728	40,508	40,909	35,225	32,264	30,442	
6	Net income	5,134	4,775	4,435	3,511	4,145	3,610	3,085	2,961	2,822	
7	Shares issued	-	-	-	-	-	-	2,600	-	-	
8	Preferred dividends	-	-	-	-	-	-	-	-	-	
9	Common dividends	(8,619)	5,626	(8,442)	(9,068)	-	(4,012)	-	-	(1,000)	
10	Closing balance	\$47,633	\$51,117	\$40,645	\$35,171	\$44,653	\$40,508	\$40,909	\$35,225	\$32,264	
11	Midyear common equity	\$49,375	\$45,917	\$42,649	\$37,949	\$42,580	\$40,708	\$38,067	\$33,744	\$31,353	Tab 5, page 1, line 13

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**Pacific Northern Gas (N.E.) Ltd.**  
**(Fort St. John/Dawson Creek Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Short term borrowings	\$1,075	\$995	\$857	\$400	(\$9,994)	(\$4,753)	\$4,167	\$8,891	\$1,771	
2	proportion	1.00%	1.00%	0.92%	0.43%	(11.39%)	(5.37%)	4.64%	10.54%	2.31%	
3	rate of return	2.32%	2.25%	2.33%	12.57%	(0.46%)	1.64%	3.36%	3.06%	2.57%	Tab 5, page 2, line 10
4	return component	0.02%	0.02%	0.02%	0.05%	0.05%	(0.09%)	0.16%	0.32%	0.06%	
5	Long term debt	\$56,887	\$52,907	\$49,209	\$54,211	\$55,195	\$52,594	\$47,568	\$41,749	\$43,626	Tab 5, page 4, line 78
6	proportion	53.00%	53.00%	53.08%	58.57%	62.88%	59.39%	52.97%	49.48%	56.84%	
7	rate of return	4.64%	4.64%	4.73%	4.79%	4.77%	4.73%	3.90%	3.63%	3.47%	Tab 5, page 4, line 79
8	return component	2.46%	2.46%	2.51%	2.81%	3.00%	2.81%	2.07%	1.79%	1.97%	
9	Preferred shares	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
10	proportion	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
11	rate of return	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	6.48%	
12	return component	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
13	Common equity	\$49,375	\$45,917	\$42,649	\$37,949	\$42,580	\$40,708	\$38,067	\$33,744	\$31,353	
14	proportion	46.00%	46.00%	46.00%	41.00%	48.51%	45.97%	42.39%	39.99%	40.85%	
15	rate of return	10.40%	10.40%	10.40%	9.25%	9.71%	9.21%	8.30%	8.26%	8.75%	
16	return component	4.78%	4.78%	4.78%	3.79%	4.71%	4.23%	3.52%	3.30%	3.58%	
17	Total capitalization	<u>\$107,337</u>	<u>\$99,819</u>	<u>\$92,715</u>	<u>\$92,559</u>	<u>\$87,780</u>	<u>\$88,549</u>	<u>\$89,802</u>	<u>\$84,384</u>	<u>\$76,750</u>	
18	Return on rate base	<u>7.27%</u>	<u>7.27%</u>	<u>7.31%</u>	<u>6.65%</u>	<u>7.77%</u>	<u>6.95%</u>	<u>5.74%</u>	<u>5.42%</u>	<u>5.60%</u>	
19	Utility rate base	<u>\$107,337</u>	<u>\$99,819</u>	<u>\$92,715</u>	<u>\$92,559</u>	<u>\$87,780</u>	<u>\$88,549</u>	<u>\$89,802</u>	<u>\$84,384</u>	<u>\$76,750</u>	Tab 2, page 1, line 18

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Energy sales (TJ)	232	232	232	141	205	138	143	140	145	Tab 6, page 3, 15 & 27
2	Average rate per GJ	\$14.01	\$13.97	\$13.50	\$18.48	\$11.32	\$15.69	\$17.19	\$15.51	\$14.05	
3	Transportation service (TJ)	720	720	720	720	597	690	709	525	744	Tab 6, page 3, 15 & 27
4	Average rate per GJ	\$0.96	\$0.98	\$1.00	\$1.02	\$1.22	\$0.99	\$0.89	\$0.98	\$0.71	
5	Total deliveries (TJ)	952	952	952	861	802	828	852	664	889	Tab 6, page 3, 15 & 27
6	Utility revenue										
7	Energy sales	\$3,294	\$3,285	\$3,172	\$2,471	\$2,320	\$2,161	\$2,453	\$2,167	\$2,036	Tab 6, page 4, 16 & 28
8	Interim rates - sales	(43)	(44)	(46)	136	-	-	-	-	-	Tab 6, page 3, 15 & 27
9	Transportation service	706	719	732	678	731	683	629	515	531	Tab 6, page 4, 16 & 28
10	Interim rates - transportation	(12)	(13)	(13)	54	-	-	-	-	-	Tab 6, page 3, 15 & 27
11	Total Utility Revenue	3,944	3,947	3,845	3,339	3,051	2,844	3,082	2,682	2,567	
12	Cost of sales	861	811	600	755	511	456	846	616	459	Tab 6, pages 7, 19 & 31
13	Gross margin	3,083	3,136	3,245	2,584	2,540	2,388	2,236	2,066	2,108	
14	Operating expenses	800	788	739	826	931	1,005	930	697	725	Tab 1, page 2, line 6
15	Maintenance expenses	192	187	180	146	224	163	155	211	106	Tab 1, page 2, line 10
16	Admin. & general expenses	280	277	251	281	287	291	359	292	273	Tab 1, page 2, line 16
17	Property taxes	137	135	133	97	97	94	91	84	83	Tab 1, page 7, line 4
18	Depreciation	369	338	299	254	257	255	217	201	177	Tab 2, page 10, 11 & 12, line 49
19	Amortization on gross deferrals	249	534	50	247	247	291	134	145	95	Tab 2, page 16, 17 & 18, lines 33, 34
20	Investment income, other revenue	(29)	(29)	(29)	(13)	(108)	(6)	(9)	(12)	(51)	Tab 1, page 8, line 7
21	Rate smoothing deferral	184	34	809	127	128	(120)	-	(97)	95	Tab 2, page 16, 17 & 18, line 20
22	Interim to permanent rate adjustment	-	-	-	-	1	-	-	-	77	
23		2,181	2,264	2,432	1,966	2,063	1,972	1,875	1,521	1,580	
24	Earned return before income taxes	902	872	813	618	468	417	361	545	529	
25	Future Income taxes on deferrals	(3)	(77)	49	(40)	23	(19)	13	(4)	(1)	Tab 2, page 16, 17 & 18, lines 34, 35
26	Income taxes	226	295	144	192	89	133	64	113	108	Tab 3, page 1, line 11
27	Earned return	\$679	\$655	\$619	\$465	\$356	\$303	\$284	\$436	\$422	
28	Utility rate base	\$8,914	\$8,651	\$7,989	\$6,519	\$7,069	\$6,337	\$5,996	\$5,741	\$5,509	Tab 2, page 1, line 17
29	Return on rate base	7.61%	7.57%	7.75%	7.14%	5.04%	4.79%	4.74%	7.59%	7.67%	Tab 5, page 1, line 14

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Plant in service beginning of year	\$18,509	\$17,656	\$16,322	\$14,914	\$14,890	\$14,185	\$13,294	\$12,918	\$12,273	Tab 2, page 4, 5 & 6, line 49
2	Additions	686	854	1,334	394	1,565	745	898	434	670	Tab 2, page 4, 5 & 6, line 49
3	Disposals	(0)	-	-	-	(133)	-	(6)	(58)	(25)	Tab 2, page 4, 5 & 6, line 49
4	Plant in service end of year	19,195	18,509	17,656	15,308	16,322	14,930	14,185	13,294	12,918	
5	Accumulated depreciation	8,479	8,082	7,717	7,517	7,391	7,238	6,955	6,714	6,544	Tab 2, page 10, 11 & 12, line 39
6	Net plant in service end of year	10,717	10,428	9,939	7,791	8,931	7,693	7,231	6,580	6,374	
7	Net plant beginning of year	10,428	9,939	8,931	7,677	7,687	7,231	6,580	6,374	5,909	Tab 2, pages 7 & 13 net of lines 1 & 1
8	Net plant in service midyear	10,572	10,183	9,435	7,734	8,309	7,462	6,905	6,477	6,142	
9	Contributions for construction	(698)	(724)	(750)	(776)	(776)	(801)	(827)	(853)	(879)	Tab 2, page 40, line 13
10	Unamortized deferred charges	(1,229)	(1,058)	(888)	(675)	(691)	(496)	(309)	(163)	(52)	Tab 2, page 16, 17 & 18, line 10
11	Deferred income taxes	-	-	-	-	-	-	-	-	-	Tab 2, page 43, line 8
12	Reserve for damages	-	-	-	-	-	-	-	-	-	
13	Pension funding in excess of expense	119	95	72	94	90	59	88	137	175	Tab 2, page 41, line 11
14	Non-pension post retirement	-	-	-	-	-	-	-	-	-	Tab 2, page 42, line 17
15	Cash working capital	150	155	120	142	137	113	139	143	123	Tab 2, page 19, 26 & 33, line 10
16	Other working capital	-	-	-	-	-	-	-	-	-	Tab 2, page 25, 32 & 39, line 15
17	Utility rate base, midyear	<u>\$8,914</u>	<u>\$8,651</u>	<u>\$7,989</u>	<u>\$6,519</u>	<u>\$7,069</u>	<u>\$6,337</u>	<u>\$5,996</u>	<u>\$5,741</u>	<u>\$5,509</u>	



**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Opening balance										
2	Share capital	\$1,132	\$1,132	\$880	\$286	\$230	\$230	\$230	\$230	\$230	
3	Contributed surplus										
4	Retained earnings	3,369	3,364	2,932	2,473	2,778	2,881	2,721	2,372	2,112	
5		4,501	4,496	3,812	2,759	3,008	3,111	2,951	2,602	2,342	
6	Net income	482	468	432	288	142	197	160	349	360	
7	Shares issued	-	-	252	257	650	-	-	-	-	
8	Preferred dividends	-	-	-	-	-	-	-	-	-	
9	Common dividends	(213)	(463)	-	-	-	(300)	-	-	(129)	
10	Closing balance	\$4,770	\$4,501	\$4,496	\$3,304	\$3,800	\$3,008	\$3,111	\$2,951	\$2,573	
11	Midyear common equity	\$4,636	\$4,499	\$4,154	\$3,031	\$3,404	\$3,060	\$3,031	\$2,777	\$2,458	Tab 5, page 1, line 9

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Short term borrowings	\$89	\$86	\$80	\$64	\$21	\$9	\$65	\$62	\$827	
2	proportion	1.00%	1.00%	1.00%	0.98%	0.30%	0.15%	1.08%	1.07%	15.02%	
3	rate of return	3.36%	3.44%	3.80%	4.98%	141.96%	(401.76%)	16.61%	3.00%	4.02%	Tab 5, page 2, line 10
4	return component	0.03%	0.03%	0.04%	0.05%	0.42%	(0.60%)	0.18%	0.03%	0.60%	
5	Long term debt	\$4,190	\$4,066	\$3,754	\$3,424	\$3,644	\$3,268	\$2,900	\$2,903	\$2,224	Tab 5, page 4, line 78
6	proportion	47.00%	47.00%	47.00%	52.52%	51.54%	51.57%	48.37%	50.56%	40.37%	
7	rate of return	4.62%	4.53%	4.91%	5.09%	5.05%	4.91%	3.59%	2.80%	3.19%	Tab 5, page 4, line 79
8	return component	2.17%	2.13%	2.31%	2.67%	2.60%	2.53%	1.74%	1.42%	1.29%	
9	Common equity	\$4,636	\$4,499	\$4,154	\$3,031	\$3,404	\$3,060	\$3,031	\$2,777	\$2,458	
10	proportion	52.00%	52.00%	52.00%	46.50%	48.16%	48.28%	50.55%	48.37%	44.61%	
11	rate of return	10.40%	10.40%	10.40%	9.50%	4.18%	5.91%	5.58%	12.70%	12.95%	
12	return component	5.41%	5.41%	5.41%	4.42%	2.01%	2.85%	2.82%	6.14%	5.78%	
13	Total capitalization	<u>\$8,914</u>	<u>\$8,651</u>	<u>\$7,989</u>	<u>\$6,519</u>	<u>\$7,069</u>	<u>\$6,337</u>	<u>\$5,996</u>	<u>\$5,741</u>	<u>\$5,509</u>	
14	Return on rate base	<u>7.61%</u>	<u>7.57%</u>	<u>7.75%</u>	<u>7.14%</u>	<u>5.04%</u>	<u>4.79%</u>	<u>4.74%</u>	<u>7.59%</u>	<u>7.67%</u>	
15	Utility rate base	<u>\$8,914</u>	<u>\$8,651</u>	<u>\$7,989</u>	<u>\$6,519</u>	<u>\$7,069</u>	<u>\$6,337</u>	<u>\$5,996</u>	<u>\$5,741</u>	<u>\$5,509</u>	Tab 2, page 1, line 17

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY INCOME & RETURN**

**SCHEDULE 1**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Energy sales (TJ)	232	232	232	141	205	138	143	140	145	Tab 6, page 3, 15 & 27
2	Average rate per GJ	\$14.02	\$13.96	\$13.68	\$18.48	\$11.32	\$15.69	\$17.19	\$15.51	\$14.05	
3	Transportation service (TJ)	720	720	720	720	597	690	709	525	744	Tab 6, page 3, 15 & 27
4	Average rate per GJ	\$0.96	\$0.98	\$1.00	\$1.02	\$1.22	\$0.99	\$0.89	\$0.98	\$0.71	
5	Total deliveries (TJ)	952	952	952	861	802	828	852	664	889	Tab 6, page 3, 15 & 27
6	Utility revenue										
7	Energy sales	\$3,295	\$3,282	\$3,216	\$2,471	\$2,320	\$2,161	\$2,453	\$2,167	\$2,036	Tab 6, page 4, 16 & 28
8	Interim rates - sales	(43)	(44)	(46)	136	-	-	-	-	-	Tab 6, page 3, 15 & 27
9	Transportation service	706	719	732	678	731	683	629	515	531	Tab 6, page 4, 16 & 28
10	Interim rates - transportation	(12)	(13)	(13)	54	-	-	-	-	-	Tab 6, page 3, 15 & 27
11	Total Utility Revenue	3,946	3,944	3,889	3,339	3,051	2,844	3,082	2,682	2,567	
12	Cost of sales	861	807	598	755	511	456	846	616	459	Tab 6, pages 7, 19 & 31
13	Gross margin	3,084	3,138	3,290	2,584	2,540	2,388	2,236	2,066	2,108	
14	Operating expenses	832	792	782	826	931	1,005	930	697	725	Tab 1, page 2, line 6
15	Maintenance expenses	192	187	180	146	224	163	155	211	106	Tab 1, page 2, line 10
16	Admin. & general expenses	292	275	255	281	287	291	359	292	273	Tab 1, page 2, line 16
17	Property taxes	137	135	133	97	97	94	91	84	83	Tab 1, page 7, line 4
18	Depreciation	376	341	299	254	257	255	217	201	177	Tab 2, page 10, 11 & 12, line 49
19	Amortization on gross deferrals	250	535	50	247	247	291	134	145	95	Tab 2, page 16, 17 & 18, lines 33, 34
20	Investment income, other revenue	(29)	(29)	(29)	(13)	(108)	(6)	(9)	(12)	(51)	Tab 1, page 8, line 7
21	Rate smoothing deferral	99	5	800	127	128	(120)	-	(97)	95	Tab 2, page 16, 17 & 18, line 20
22	Interim to permanent rate adjustment	-	-	-	-	1	-	-	-	77	
23		2,149	2,241	2,471	1,966	2,063	1,972	1,875	1,521	1,580	
24	Earned return before income taxes	935	896	819	618	468	417	361	545	529	
25	Future Income taxes on deferrals	(3)	(77)	49	(40)	23	(19)	13	(4)	(1)	Tab 2, page 16, 17 & 18, lines 34, 35
26	Income taxes	220	294	142	192	89	133	64	113	108	Tab 3, page 1, line 11
27	Earned return	\$719	\$680	\$627	\$465	\$356	\$303	\$284	\$436	\$422	
28	Utility rate base	\$9,490	\$8,999	\$8,098	\$6,519	\$7,069	\$6,337	\$5,996	\$5,741	\$5,509	Tab 2, page 1, line 17
29	Return on rate base	7.57%	7.55%	7.75%	7.14%	5.04%	4.79%	4.74%	7.59%	7.67%	Tab 5, page 1, line 14

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**UTILITY RATE BASE**

**SCHEDULE 2**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Plant in service beginning of year	\$18,976	\$17,874	\$16,322	\$14,914	\$14,890	\$14,185	\$13,294	\$12,918	\$12,273	Tab 2, page 4, 5 & 6, line 49
2	Additions	894	1,102	1,552	394	1,565	745	898	434	670	Tab 2, page 4, 5 & 6, line 49
3	Disposals	(0)	-	-	-	(133)	-	(6)	(58)	(25)	Tab 2, page 4, 5 & 6, line 49
4	Plant in service end of year	19,870	18,976	17,874	15,308	16,322	14,930	14,185	13,294	12,918	
5	Accumulated depreciation	8,488	8,085	7,717	7,517	7,391	7,238	6,955	6,714	6,544	Tab 2, page 10, 11 & 12, line 39
6	Net plant in service end of year	11,382	10,891	10,157	7,791	8,931	7,693	7,231	6,580	6,374	
7	Net plant beginning of year	10,891	10,157	8,931	7,677	7,687	7,231	6,580	6,374	5,909	Tab 2, pages 7 & 13 net of lines 1 & 1
8	Net plant in service midyear	11,137	10,524	9,544	7,734	8,309	7,462	6,905	6,477	6,142	
9	Contributions for construction	(698)	(724)	(750)	(776)	(776)	(801)	(827)	(853)	(879)	Tab 2, page 40, line 13
10	Unamortized deferred charges	(1,230)	(1,058)	(888)	(675)	(691)	(496)	(309)	(163)	(52)	Tab 2, page 16, 17 & 18, line 10
11	Deferred income taxes	-	-	-	-	-	-	-	-	-	Tab 2, page 43, line 8
12	Reserve for damages	-	-	-	-	-	-	-	-	-	
13	Pension funding in excess of expense	119	95	72	94	90	59	88	137	175	Tab 2, page 41, line 11
14	Non-pension post retirement	-	-	-	-	-	-	-	-	-	Tab 2, page 42, line 17
15	Cash working capital	163	163	121	142	137	113	139	143	123	Tab 2, page 19, 26 & 33, line 10
16	Other working capital	-	-	-	-	-	-	-	-	-	Tab 2, page 25, 32 & 39, line 15
17	Utility rate base, midyear	\$9,490	\$8,999	\$8,098	\$6,519	\$7,069	\$6,337	\$5,996	\$5,741	\$5,509	



**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**COMMON EQUITY**

**SCHEDULE 4**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Opening balance										
2	Share capital	\$1,240	\$1,240	\$880	\$286	\$230	\$230	\$230	\$230	\$230	
3	Contributed surplus										
4	Retained earnings	3,509	3,370	2,932	2,473	2,778	2,881	2,721	2,372	2,112	
5		4,749	4,610	3,812	2,759	3,008	3,111	2,951	2,602	2,342	
6	Net income	513	487	438	288	142	197	160	349	360	
7	Shares issued	-	-	360	257	650	-	-	-	-	
8	Preferred dividends	-	-	-	-	-	-	-	-	-	
9	Common dividends	(142)	(348)	-	-	-	(300)	-	-	(129)	
10	Closing balance	\$5,120	\$4,749	\$4,610	\$3,304	\$3,800	\$3,008	\$3,111	\$2,951	\$2,573	
11	Midyear common equity	\$4,935	\$4,680	\$4,211	\$3,031	\$3,404	\$3,060	\$3,031	\$2,777	\$2,458	Tab 5, page 1, line 9

**Pacific Northern Gas (N.E.) Ltd.**  
**(Tumbler Ridge Division)**

**RETURN ON CAPITAL**

**SCHEDULE 5**  
**(000's)**

Line No.	Description	Test Year 2027	Test Year 2026	Test Year 2025	Decision 2024	Actual 2024	Actual 2023	Actual 2022	Actual 2021	Actual 2020	Source
1	Short term borrowings	\$95	\$90	\$81	\$64	\$21	\$9	\$65	\$62	\$827	
2	proportion	1.00%	1.00%	1.00%	0.98%	0.30%	0.15%	1.08%	1.07%	15.02%	
3	rate of return	3.34%	3.42%	3.83%	4.98%	141.96%	(401.76%)	16.61%	3.00%	4.02%	Tab 5, page 2, line 10
4	return component	0.03%	0.03%	0.04%	0.05%	0.42%	(0.60%)	0.18%	0.03%	0.60%	
5	Long term debt	\$4,460	\$4,230	\$3,806	\$3,424	\$3,644	\$3,268	\$2,900	\$2,903	\$2,224	Tab 5, page 4, line 78
6	proportion	47.00%	47.00%	47.00%	52.52%	51.54%	51.57%	48.37%	50.56%	40.37%	
7	rate of return	4.54%	4.49%	4.90%	5.09%	5.05%	4.91%	3.59%	2.80%	3.19%	Tab 5, page 4, line 79
8	return component	2.13%	2.11%	2.30%	2.67%	2.60%	2.53%	1.74%	1.42%	1.29%	
9	Common equity	\$4,935	\$4,680	\$4,211	\$3,031	\$3,404	\$3,060	\$3,031	\$2,777	\$2,458	
10	proportion	52.00%	52.00%	52.00%	46.50%	48.16%	48.28%	50.55%	48.37%	44.61%	
11	rate of return	10.40%	10.40%	10.40%	9.50%	4.18%	5.91%	5.58%	12.70%	12.95%	
12	return component	5.41%	5.41%	5.41%	4.42%	2.01%	2.85%	2.82%	6.14%	5.78%	
13	Total capitalization	<u>\$9,490</u>	<u>\$8,999</u>	<u>\$8,098</u>	<u>\$6,519</u>	<u>\$7,069</u>	<u>\$6,337</u>	<u>\$5,996</u>	<u>\$5,741</u>	<u>\$5,509</u>	
14	Return on rate base	<u>7.57%</u>	<u>7.55%</u>	<u>7.75%</u>	<u>7.14%</u>	<u>5.04%</u>	<u>4.79%</u>	<u>4.74%</u>	<u>7.59%</u>	<u>7.67%</u>	
15	Utility rate base	<u>\$9,490</u>	<u>\$8,999</u>	<u>\$8,098</u>	<u>\$6,519</u>	<u>\$7,069</u>	<u>\$6,337</u>	<u>\$5,996</u>	<u>\$5,741</u>	<u>\$5,509</u>	Tab 2, page 1, line 17

**Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd.  
Reconsideration of Orders G-270-25 and G-284-25 and Accompanying Decisions on the PNG-West  
and PNG(NE) 2025-2027 Revenue Requirements Applications  
Request for Change to 2026 Interim Rates**

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**Exhibit F – Residential and Small Commercial Bill Impacts of Proposed Rate Changes**

**Pacific Northern Gas Ltd.  
(PNG-West Division)**

**Bill Comparison  
January 2026 Interim Rates to Proposed 2026 Revised Interim Rates**

Customer Classification	Annual Use	Interim Rates Jan. 1, 2026 \$/GJ	Annual Bill Estimate \$	Revised Interim Mar. 1, 2026 \$/GJ	Annual Bill			
					Estimate \$	Difference \$ %		
<b>Residential:</b>	64.1 GJ							
Monthly Basic Charge		3.192	204.60	3.433	220.08	15.48	7.6%	
Delivery Charge		20.592	1,319.95	22.156	1,420.20	100.25	7.6%	
Company Use Charge		0.095	6.09	0.095	6.09	-	-	
GCV A Co. Use Rider		(0.075)	(4.81)	(0.075)	(4.81)	-	-	
RSAM Rider		(0.133)	(8.53)	(0.133)	(8.53)	-	-	
LCCR Rider		0.008	0.51	0.008	0.51	-	-	
Interim Rate Refund Rider		0.000	-	0.000	-	-	-	
				1,517.82		1,633.55	115.73	7.6%
Gas Supply Charge		2.891	185.31	2.891	185.31	-	-	
GCV A Rider		(0.294)	(18.85)	(0.294)	(18.85)	-	-	
				166.47		166.47	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-	
			\$26.276 /GJ	\$1,684.28	\$28.081 /GJ	\$1,800.02	\$115.73	6.9%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	316.4 GJ							
Monthly Basic Charge		1.506	476.64	1.621	512.76	36.12	7.6%	
Delivery Charge		17.311	5,477.20	18.624	5,892.63	415.43	7.6%	
Company Use Charge		0.095	30.06	0.095	30.06	-	-	
GCV A Co. Use Rider		(0.075)	(23.73)	(0.075)	(23.73)	-	-	
RSAM Rider		(0.133)	(42.08)	(0.133)	(42.08)	-	-	
LCCR Rider		0.008	2.53	0.008	2.53	-	-	
Interim Rate Refund Rider		0.000	-	0.000	-	-	-	
				5,920.62		6,372.17	451.55	7.6%
Gas Supply Charge		2.876	909.97	2.876	909.97	-	-	
GCV A Rider		(0.294)	(93.02)	(0.294)	(93.02)	-	-	
				816.95		816.95	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-	
			\$21.294 /GJ	\$6,737.56	\$22.722 /GJ	\$7,189.12	\$451.55	6.7%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

**Granisle Propane**

Customer Classification	Annual Use	Interim Rates Jan. 1, 2026 \$/GJ	Annual Bill Estimate \$	Proposed Rates Mar. 1, 2026 \$/GJ	Annual Bill			
					Estimate \$	Difference \$ %		
<b>Residential:</b>	35.1 GJ							
Delivery Charge		5.829	204.60	6.270	220.08	15.48	7.6%	
		11.882	417.06	12.783	448.68	31.62	7.6%	
Company Use Charge		0.095	3.33	0.095	3.33	-	-	
GCV A Co. Use Rider		(0.075)	(2.63)	(0.075)	(2.63)	-	-	
LCCR Rider		0.008	0.28	0.008	0.28	-	-	
Interim Rate Refund Rider		0.000	-	0.000	-	-	-	
				622.64		669.75	47.10	7.6%
Gas Supply Charge		2.891	101.47	2.891	101.47	-	-	
GCV A Rider		(0.294)	(10.32)	(0.294)	(10.32)	-	-	
				91.15		91.15	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-	
			\$20.336 /GJ	\$713.79	\$21.678 /GJ	\$760.90	\$47.10	6.6%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	152.0 GJ							
Monthly Basic Charge		1.346	204.60	1.448	220.07	15.47	7.6%	
Delivery Charge		11.882	1,806.06	12.783	1,943.02	136.96	7.6%	
Company Use Charge		0.095	14.44	0.095	14.44	-	-	
GCV A Co. Use Rider		(0.075)	(11.40)	(0.075)	(11.40)	-	-	
LCCR Rider		0.008	1.22	0.008	1.22	-	-	
Interim Rate Refund Rider		0.000	-	0.000	-	-	-	
				2,014.92		2,167.34	152.42	7.6%
Gas Supply Charge		2.876	437.15	2.876	437.15	-	-	
GCV A Rider		(0.294)	(44.69)	(0.294)	(44.69)	-	-	
				392.46		392.46	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-	
			\$15.838 /GJ	\$2,407.38	\$16.841 /GJ	\$2,559.81	\$152.42	6.3%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**Bill Comparison  
January 2026 Interim Rates to Proposed 2026 Revised Interim Rates**

**FORT ST. JOHN AREA**

Customer Classification	Annual Use	Interim Rates Jan 1, 2026 \$/ GJ	Annual Bill Estimate \$	Revised Interim Mar. 1, 2026 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
<b>Residential:</b>	96.8 GJ						
Monthly Basic Charge		1.071	103.68	1.165	112.80	9.12	8.8%
Delivery Charge		7.190	695.99	7.814	756.40	60.40	8.7%
Company Use Charge		0.053	5.13	0.053	5.13	-	-
GCVA Co. Use Rider		(0.075)	(7.26)	(0.075)	(7.26)	-	-
RSAM Rider		(0.198)	(19.17)	(0.198)	(19.17)	-	-
LCCR Rider		0.008	0.77	0.008	0.77	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			779.15		848.67	69.52	8.9%
Gas Supply Charge		2.891	279.85	2.891	279.85	-	-
GCVA Rider		(0.294)	(28.46)	(0.294)	(28.46)	-	-
			251.39		251.39	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$10.646 /GJ	\$1,030.54	\$11.364 /GJ	\$1,100.06	\$69.52	6.7%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	445.7 GJ						
Monthly Basic Charge		0.233	103.80	0.253	112.92	9.12	8.8%
Delivery Charge		5.415	2,413.47	5.886	2,623.39	209.92	8.7%
Company Use Charge		0.053	23.62	0.053	23.62	-	-
GCVA Co. Use Rider		(0.075)	(33.43)	(0.075)	(33.43)	-	-
RSAM Rider		(0.198)	(88.25)	(0.198)	(88.25)	-	-
LCCR Rider		0.008	3.57	0.008	3.57	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			2,422.78		2,641.82	219.04	9.0%
Gas Supply Charge		2.876	1,281.83	2.876	1,281.83	-	-
GCVA Rider		(0.294)	(131.04)	(0.294)	(131.04)	-	-
			1,150.80		1,150.80	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$8.018 /GJ	\$3,573.58	\$8.509 /GJ	\$3,792.62	\$219.04	6.1%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**Bill Comparison  
January 2026 Interim Rates to Proposed 2026 Revised Interim Rates**

**DAWSON CREEK AREA**

Customer Classification	Annual Use	Interim Rates Jan 1, 2026 \$/GJ	Annual Bill Estimate \$	Revised Interim Mar. 1, 2026 \$/GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
<b>Residential:</b>	90.2 GJ						
Monthly Basic Charge		1.149	103.68	1.251	112.80	9.12	8.8%
Delivery Charge		6.992	630.68	7.630	688.23	57.55	9.1%
Company Use Charge		0.053	4.78	0.053	4.78	-	-
GCVA Co. Use Rider		(0.075)	(6.77)	(0.075)	(6.77)	-	-
RSAM Rider		(0.198)	(17.86)	(0.198)	(17.86)	-	-
LCCR Rider		0.008	0.72	0.008	0.72	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			715.24		781.90	66.67	9.3%
Gas Supply Charge		2.891	260.77	2.891	260.77	-	-
GCVA Rider		(0.294)	(26.52)	(0.294)	(26.52)	-	-
			234.25		234.25	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$10.526 /GJ	\$949.49	\$11.266 /GJ	\$1,016.15	\$66.67	7.0%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	476.3 GJ						
Monthly Basic Charge		0.218	103.80	0.237	112.92	9.12	8.8%
Delivery Charge		4.878	2,323.39	5.322	2,534.87	211.48	9.1%
Company Use Charge		0.053	25.24	0.053	25.24	-	-
GCVA Co. Use Rider		(0.075)	(35.72)	(0.075)	(35.72)	-	-
RSAM Rider		(0.198)	(94.31)	(0.198)	(94.31)	-	-
LCCR Rider		0.008	3.81	0.008	3.81	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			2,326.22		2,546.81	220.60	9.5%
Gas Supply Charge		2.876	1,369.84	2.876	1,369.84	-	-
GCVA Rider		(0.294)	(140.03)	(0.294)	(140.03)	-	-
			1,229.81		1,229.81	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$7.466 /GJ	\$3,556.02	\$7.929 /GJ	\$3,776.62	\$220.60	6.2%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

**Pacific Northern Gas (N.E.) Ltd.  
(Fort St. John/Dawson Creek Division)**

**Bill Comparison  
January 2026 Interim Rates to Proposed 2026 Revised Interim Rates**

**Average of Fort St. John and Dawson Creek**

Customer Classification	Annual Use	Interim Rates Jan 1, 2026 \$/ GJ	Annual Bill Estimate \$	Revised Interim Mar. 1, 2026 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
<b>Residential:</b>	93.5 GJ						
Monthly Basic Charge		1.109	103.68	1.206	112.80	9.12	8.8%
Delivery Charge		7.091	663.01	7.722	722.01	59.00	8.9%
Company Use Charge		0.053	4.96	0.053	4.96	-	-
GCVA Co. Use Rider		(0.075)	(7.01)	(0.075)	(7.01)	-	-
RSAM Rider		(0.198)	(18.51)	(0.198)	(18.51)	-	-
LCCR Rider		0.008	0.75	0.008	0.75	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			746.87		814.99	68.12	9.1%
Gas Supply Charge		2.891	270.31	2.891	270.31	-	-
GCVA Rider		(0.294)	(27.49)	(0.294)	(27.49)	-	-
			242.82		242.82	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$10.585 /GJ	\$989.69	\$11.313 /GJ	\$1,057.80	\$68.12	6.9%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	461.0 GJ						
Monthly Basic Charge		0.225	103.80	0.245	112.92	9.12	8.8%
Delivery Charge		5.147	2,372.54	5.604	2,583.44	210.90	8.9%
Company Use Charge		0.053	24.43	0.053	24.43	-	-
GCVA Co. Use Rider		(0.075)	(34.58)	(0.075)	(34.58)	-	-
RSAM Rider		(0.198)	(91.28)	(0.198)	(91.28)	-	-
LCCR Rider		0.008	3.69	0.008	3.69	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			2,378.61		2,598.63	220.02	9.3%
Gas Supply Charge		2.876	1,325.84	2.876	1,325.84	-	-
GCVA Rider		(0.294)	(135.53)	(0.294)	(135.53)	-	-
			1,190.30		1,190.30	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$7.742 /GJ	\$3,568.91	\$8.219 /GJ	\$3,788.93	\$220.02	6.2%

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

Note: This bill comparison is the average of the uses per account and rates that apply to each of the Fort St. John and Dawson Creek delivery areas.

**Pacific Northern Gas (N.E.) Ltd.  
(Tumbler Ridge Division)**

**Bill Comparison  
January 2026 Interim Rates to Proposed 2026 Revised Interim Rates**

Customer Classification	Annual Use	Interim Rates Jan 1, 2026 \$/ GJ	Annual Bill Estimate \$	Revised Interim Mar. 1, 2026 \$/ GJ	Annual Bill Estimate \$	Annual Bill Difference	
						\$	%
<b>Residential:</b>	70.7 GJ						
Monthly Basic Charge		1.691	119.52	1.691	119.52	-	-
Delivery Charge		12.589	890.04	12.341	872.51	(17.53)	(2.0%)
Company Use Charge		0.015	1.06	0.015	1.06	-	-
GCVA Co. Use Rider		(0.075)	(5.30)	(0.075)	(5.30)	-	-
RSAM Rider		(0.229)	(16.19)	(0.229)	(16.19)	-	-
LCCR Rider		0.008	0.57	0.008	0.57	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			989.70		972.17	(17.53)	(1.8%)
Gas Supply Charge		2.891	204.39	2.891	204.39	-	-
GCVA Rider		(0.294)	(20.79)	(0.294)	(20.79)	-	-
			183.61		183.60	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$16.596 /GJ	\$1,173.31	\$16.348 /GJ	\$1,155.77	(\$17.53)	(1.5%)

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

<b>Small Commercial:</b>	427.7 GJ						
Monthly Basic Charge		0.280	119.76	0.280	119.76	-	-
Delivery Charge		9.961	4,260.32	9.783	4,184.19	(76.13)	(1.8%)
Company Use Charge		0.015	6.42	0.015	6.42	-	-
GCVA Co. Use Rider		(0.075)	(32.08)	(0.075)	(32.08)	-	-
RSAM Rider		(0.229)	(97.94)	(0.229)	(97.94)	-	-
LCCR Rider		0.008	3.42	0.008	3.42	-	-
Interim Rate Refund Rider		0.000	-	0.000	-	-	-
			4,259.90		4,183.77	(76.13)	(1.8%)
Gas Supply Charge		2.876	1,230.07	2.876	1,230.07	-	-
GCVA Rider		(0.294)	(125.74)	(0.294)	(125.74)	-	-
			1,104.32		1,104.32	-	-
Carbon Tax*		0.0000	-	0.0000	-	-	-
		\$12.542 /GJ	\$5,364.22	\$12.364 /GJ	\$5,288.09	(\$76.13)	(1.4%)

\* BC Carbon Tax was eliminated by the BC government effective April 1, 2025.

# BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the *Utilities Commission Act*, RSBC 1996 c 473

and

Pacific Northern Gas Ltd. Application for Reconsideration and Variance  
of British Columbia Utilities Commission Order G-270-25  
on the Pacific Northern Gas Ltd. PNG-West 2025 to 2027 Revenue Requirements  
and Stay of Proceedings

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## BOOK OF AUTHORITIES

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1. *Pipeline Regulation*, BC Reg 210/2010
2. *Utilities Commission Act*, RSBC 1996, c 473
3. *Bell Canada v. Canada (Attorney General)*, 2011 FC 1120
4. *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106
5. *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1993), 66 BCLR (2d) 1 (CA)

B.C. Reg. 281/2010  
British Columbia Energy Regulator

Deposited September 24, 2010  
effective October 4, 2010, except  
section 7 (1) (b) and (d) effective October 4, 2011

This consolidation is current to January 20, 2026.

[Link to consolidated regulation \(PDF\)](#)

[Link to Point in Time](#)

## ***Energy Resource Activities Act***

### **PIPELINE REGULATION**

[Last amended April 1, 2025 by B.C. Reg. 26/2025]

#### ***Contents***

- 1 Definitions
- 2 Applications for a pipeline permit
- 3 Standards
- 4 Notices and other submissions
- 5 Requirements after construction of pipeline
- 6 Pipeline crossings
- 7 Integrity management and damage prevention programs
- 7.1 Venting of natural gas during operation to depressure pipeline
- 8 Repealed
- 9 Deactivation
- 10 Reactivation
- 11 Obligations on cancellation or cessation of operations
- 12 Spillage, damage and malfunction records
- 12.1 Invasive plant compliance record
- 13 Record retention
- 13.1 Records
- 14 Exemptions

#### **Definitions**

**1** (1) In this regulation:

**"abandon"**, in respect of a pipeline or piping, means permanently to remove from service;

**"Act"** means the *Energy Resource Activities Act*;

**"CSA Z662"** means the standard published by the CSA Group as CSA Z662, Oil and Gas Pipeline Systems, as amended from time to time;

**"professional engineer"** means a person who is registered under the *Professional Governance Act* as a professional engineer.

[am. B.C. Regs. 147/2014, Sch. 2, s. 2; 202/2023, Sch. 10, s. 1; 26/2025, Sch. 7, s. 1.]

## **Applications for a pipeline permit**

2 The following information and records must be submitted on application for a pipeline permit:

- (a) if a fluid containing hydrogen sulphide gas is to be transported in the pipeline,
  - (i) the chemical analysis of the gas or fluid to be transported, and
  - (ii) the expected release volume, expressed at standard conditions of 15°C and 101.3 kPa, of hydrogen sulphide from the pipeline;
- (b) a map clearly showing
  - (i) the proposed route of the pipeline,
  - (ii) if the pipeline is to be constructed on private lands, the boundaries of the land of each land owner,
  - (iii) surface and environmental features and structures, including stream crossings and lakes, and
  - (iv) the right of way of a highway, road, railway, underground communication or power line or other pipeline to be crossed or within 500 metres of the proposed pipeline;
- (c) if CSA Z662 and Annex A of CSA Z662 are not applicable to the substance to be transported in the pipeline,
  - (i) an engineering assessment demonstrating that the requirements in CSA Z662 and Annex A of CSA Z662 are appropriate for the substance to be transported in the pipeline, or
  - (ii) alternative codes or standards that
    - (A) are appropriate for the substance to be transported in the pipeline, and
    - (B) provide for a level of safety and protection in the design, construction, operation, maintenance, deactivation, reactivation and abandonment of the pipeline that is equivalent to, or greater than, the level provided by CSA Z662 and Annex A of CSA Z662 in relation to other substances;
- (d) if alternative codes or standards referred to in paragraph (c) (ii) are submitted, an engineering assessment demonstrating that the

alternative codes or standards meet the requirements under paragraph (c) (ii) (A) and (B).

[am. B.C. Reg. 26/2025, Sch. 7, s. 2.]

## Standards

- 3** (1) Subject to subsection (2), a pipeline permit holder must not design, construct, operate, maintain, deactivate, reactivate or abandon the pipeline that is the subject of the permit except in accordance with
- (a) CSA Z662 and Annex A of CSA Z662, if
    - (i) they are applicable to the substance transported or to be transported in the pipeline, or
    - (ii) the engineering assessment referred to in section 2 (c) (i) demonstrates that the requirements in CSA Z662 and Annex A of CSA Z662 are appropriate for the substance transported or to be transported in the pipeline, or
  - (b) if paragraph (a) (i) or (ii) does not apply, the alternative codes or standards referred to in section 2 (c) (ii).
- (2) A pipeline permit holder who constructs a pipeline under agricultural land must ensure the pipeline has a minimum cover of 0.8 metres.
- (3) Repealed. [B.C. Reg. 147/2014, Sch. 2, s. 3.]

[am. B.C. Regs. 147/2014, Sch. 2, s. 3; 54/2020, s. 1; 26/2025, Sch. 7, s. 3.]

## Notices and other submissions

- 4** (1) A pipeline permit holder must notify the regulator
- (a) at least 2 days before beginning construction of a pipeline of its intention to begin construction,
  - (b) at least 2 days before beginning a pressure test of a pipeline of its intention to begin testing, and
  - (c) before beginning operation of a pipeline of its intention to begin operation.
- (2) Within 60 days after a pipeline permit holder completes construction of the pipeline and all associated activities, the holder must prepare and submit to the regulator post-construction plot plans showing the location of the pipeline and all associated energy resource activities.
- (3) Within 90 days after a pipeline permit holder completes construction of or any permitted modifications to the pipeline, the holder must
- (a) prepare record drawings,
  - (b) have the record drawings signed and sealed by a professional engineer, and
  - (c) submit to the regulator

- (i) the record drawings, and
- (ii) the pipe and component specifications.

[am. B.C. Regs. 147/2014, Sch. 2, s. 4; 54/2020, s. 2; 202/2023, Sch. 10, ss. 2 and 3; 26/2025, Sch. 7, s. 4.]

### **Requirements after construction of pipeline**

- 5** (1) Before beginning operation of a pipeline, a pipeline permit holder must do all of the following:
- (a) test the pipeline in accordance with CSA Z662, or the codes or standards referred to in section 2 (c), as applicable;
  - (b) inspect and test all control and safety devices to ensure that the devices are in good working order;
  - (c) take any other steps reasonably necessary to ensure that the pipeline is safe for use.
- (2) A pipeline permit holder must restore, in accordance with subsection (3), the surface of the land disturbed by the construction of a pipeline by
- (a) removing all structures installed to facilitate construction and not required for the operation of the pipeline, and
  - (b) stabilizing, contouring, conditioning or reconstructing the surface of the land to the extent reasonable in the circumstances.
- (3) Restoration work under subsection (2) must be carried out
- (a) as soon as practicable, considering, without limitation, weather and ground conditions, while construction of the pipeline is underway, and,
  - (b) with respect to any restoration work not completed when construction of the pipeline is completed, as soon as practicable after construction of the pipeline is completed.
- (4) A pipeline permit holder must ensure that, after the pipeline is constructed, the right of way is kept free of garbage, debris and derelict equipment.

[am. B.C. Regs. 54/2020, s. 3; 26/2025, Sch. 7, s. 5.]

### **Pipeline crossings**

- 6** (1) If a pipeline is being or has been constructed across, along, over or under a public place or the right of way of a highway, road, railway, underground communication or power line or other pipeline, the pipeline permit holder must
- (a) take all reasonable steps so as not to endanger public safety or the environment, and
  - (b) restore, to the extent reasonable in the circumstances, any infrastructure damaged or removed during the construction of the pipeline.

- (2) A pipeline permit holder must give notice in accordance with subsection (3) before beginning any work of construction, maintenance or repair of a pipeline along, over or under a public place or the right of way of a highway, road, railway, underground communication or power line or other pipeline.
- (3) A notice under subsection (2) must
  - (a) be given to the owner of or authority responsible for the public place, highway, road, railway, underground communication line, power line or pipeline, and
  - (b) subject to subsection (4), be given at least 5 days before beginning the work, unless the pipeline permit holder and the owner or authority have agreed that the notice is to be provided by another time, in which case the notice must be provided by that other time.
- (4) In the case of emergency, work referred to in subsection (1) may be begun immediately after giving notice under subsection (2).

### **Integrity management and damage prevention programs**

**7** (1) In this section:

**"damage prevention program"** means a program for the purpose of anticipating and preventing damage to a permit holder's pipeline;

**"pipeline integrity management program"** means a program for the purpose of managing the integrity of a permit holder's pipeline.

- (1.1) A pipeline permit holder must ensure that the pipeline integrity management program for the pipeline complies with
  - (a) CSA Z662, or the codes or standards referred to in section 2 (c), as applicable, and
  - (b) Annex N of CSA Z662.
- (2) A pipeline permit holder must not operate a pipeline approved by the permit unless
  - (a) the holder has first prepared a damage prevention program, and
  - (b) the pipeline is operated in accordance with the damage prevention program.
- (3) A pipeline permit holder must not construct or operate a pipeline approved by the permit unless the holder has first prepared a pipeline integrity management program.
- (4) A pipeline permit holder must not construct, operate, maintain, repair, deactivate or abandon a pipeline approved by the permit unless the pipeline is constructed, operated, maintained, repaired, deactivated or abandoned in accordance with the permit holder's pipeline integrity management program.

- (5) A pipeline permit holder must not construct, operate, maintain, repair, deactivate or abandon a pipeline approved by the permit, unless
- (a) the entirety of the pipeline is above ground, or
  - (b) the holder is a member of BC One Call and the holder's records with BC One Call are current.
- (6) On the request of an official, a pipeline permit holder must make the following available to the regulator as requested:
- (a) a copy of the pipeline integrity management program;
  - (b) a description of the damage prevention program.

[en. B.C. Reg. 54/2020, s. 4; am. B.C. Regs. 289/2020, s. 1; 202/2023, Sch. 10, s. 2; 26/2025, Sch. 7, s. 6.]

### **Venting of natural gas during operation to depressure pipeline**

**7.1** (1) A pipeline permit holder must not vent natural gas during an operation to depressure a pipeline unless

- (a) the gas heating value, volume or flow rate are insufficient to support stable combustion,
- (b) the venting is conducted in a manner that does not constitute a safety hazard,
- (c) the venting does not cause off-site odours,
- (d) the quantity of vented gas is minimized, and
- (e) the duration of venting is minimized.

(2) Despite subsection (1) (a) a permit holder may vent natural gas if

- (a) an operation to depressure a pipeline is needed to address an imminent risk to health, safety or the environment,
- (b) natural gas conservation or destruction would result in an interruption of the natural gas supply to the public, or
- (c) natural gas conservation or destruction equipment is not available at the site and it is not feasible to use portable conservation or destruction equipment due to access limitations or the configuration of the pipeline at the site.

[en. B.C. Reg. 256/2024, App. 3, s. 1.]

### **Repealed**

**8** Repealed. [B.C. Reg. 204/2013, s. 5.]

### **Deactivation**

**9** (1) This section applies if, for a period of 18 consecutive calendar months, a pipeline permit holder does not transport fluids through the holder's permitted pipeline or part of the pipeline.

- (2) The period referred to in subsection (1) begins, as applicable,
  - (a) the day after the last day fluid is transported through the permitted pipeline or part of the pipeline, if the pipeline or part has been used to transport fluids, or
  - (b) the day after construction of the permitted pipeline or part of the pipeline is completed, if the pipeline or part has not been used to transport fluids.
- (3) Before the expiry of the period referred to in subsection (1), the pipeline permit holder must do one of the following:
  - (a) deactivate the permitted pipeline or part of the pipeline and notify the regulator on completion of the deactivation;
  - (b) submit to the regulator a plan to deactivate the permitted pipeline or part of the pipeline after the end of that period;
  - (c) submit to the regulator a plan for resuming or beginning, as applicable, the transportation of fluids through the permitted pipeline or part of the pipeline.
- (4) If a plan is submitted to the regulator under subsection (3) (b) or (c),
  - (a) the plan must be approved by the regulator, and
  - (b) the pipeline permit holder must implement the plan as approved by the regulator.

[en. B.C. Reg. 289/2020, s. 2; am. B.C. Reg. 202/2023, Sch. 10, s. 2.]

## **Reactivation**

- 10** (1) Before reactivating a pipeline, the pipeline permit holder must notify the regulator of the intention to carry out the reactivation.
- (2) For greater certainty, if a permit relating to a deactivated pipeline has been suspended, the pipeline may not be reactivated unless the suspension is rescinded.

[en. B.C. Reg. 54/2020, s. 5; am. B.C. Reg. 202/2023, Sch. 10, s. 2.]

## **Obligations on cancellation or cessation of operations**

- 11** (1) For the purposes of section 40 (e) of the Act, a pipeline permit holder, a former pipeline permit holder, a pipeline authorization holder or a former pipeline authorization holder, as the case may be, must abandon the pipeline.
- (2) A pipeline permit holder who intends to abandon a pipeline on Crown land must do everything referred to in section 19 (1) of the Environmental Protection and Management Regulation.

[en. B.C. Reg. 54/2020, s. 5.]

## **Spillage, damage and malfunction records**

- 12** (1) A pipeline permit holder must maintain records of any spillage and any damage or malfunction likely to cause spillage that could be a risk to public safety or the environment.
- (2) A pipeline permit holder must keep records of an operation to depressure a pipeline under section 7.1 (2), including all of the following:
- (a) the dates on which the operation to depressure a pipeline was carried out;
  - (b) the location of the operation to depressure a pipeline;
  - (c) the measures taken to reduce emissions of natural gas;
  - (d) the volume, in m<sup>3</sup>, of natural gas emitted.

[am. B.C. Regs. 147/2014, Sch. 2, s. 6; 256/2024, App. 3, s. 2.]

### **Invasive plant compliance record**

- 12.1** A person who carries out energy resource activities within an operating area must prepare and maintain an invasive plant compliance record that describes the activities carried out for the purpose of complying with the obligations described in section 15 of the Environmental Protection and Management Regulation, including all of the following:
- (a) the assessment and monitoring activities carried out for the purpose of determining whether invasive plants
    - (i) are present or established, or may become established, or
    - (ii) have spread to adjacent areas;
  - (b) the location, type and distribution of each species of invasive plants found through assessment and monitoring activities;
  - (c) the activities carried out for the purpose of preventing the following:
    - (i) the transportation of seed, plant parts or propagules of invasive plants;
    - (ii) the establishment of invasive plants, including the removal of invasive plants;
  - (d) the revegetation activities carried out, including the plant species used for revegetation;
  - (e) the activities carried out for the purpose of ensuring that revegetated plants are successfully established;
  - (f) with respect to the activities described in this section,
    - (i) the dates on which the activities were carried out, and
    - (ii) the processes and equipment used in carrying out the activities;
  - (g) the qualifications of the persons
    - (i) carrying out assessment and monitoring activities, and
    - (ii) supervising the activities described in this section.

## Record retention

- 13** A pipeline permit holder must comply with the record retention requirements set out in CSA Z662 and Annex N of CSA Z662, and, if applicable, the codes or standards referred to in section 2 (c).

[am. B.C. Regs. 147/2014, Sch. 2, s. 7; 26/2025, Sch. 7, s. 7.]

## Records

- 13.1** The records, reports and plans required under this regulation are prescribed for the purposes of section 38 of the Act.

[en. B.C. Reg. 145/2023, App. 7.]

## Exemptions

- 14** An official may exempt a pipeline permit holder or former pipeline permit holder from complying with one or more provisions of this regulation if the official is satisfied that, in the circumstances,

- (a) compliance with the provision or provisions is not reasonably practicable, or
- (b) the exemption is in the public interest.

[am. B.C. Reg. 147/2014, Sch. 2, s. 8.]

[Provisions relevant to the enactment of this regulation: [Energy Resource Activities Act](#), S.B.C. 2008, c. 36, ss. 111 and 112.]

This Act is current to January 20, 2026

See the [Tables of Legislative Changes](#) for this Act's legislative history, including any changes not in force.

## **UTILITIES COMMISSION ACT**

**[RSBC 1996] CHAPTER 473**

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### **Definitions**

**1** (1) In this Act:

**"appraisal"** means appraisal by the commission;

**"authority"** means the British Columbia Hydro and Power Authority;

**"British Columbia's energy objectives"** has the same meaning as in section 1 (1) of the *Clean Energy Act*;

**"commission"** means the British Columbia Utilities Commission continued under this Act;

**"compensation"** means a rate, remuneration, gain or reward of any kind paid, payable, promised, demanded, received or expected, directly or indirectly, and includes a promise or undertaking by a public utility to provide service as consideration for, or as part of, a proposal or contract to dispose of land or any interest in it;

**"costs"** includes fees, counsel fees and expenses;

**"demand-side measure"** has the same meaning as in section 1 (1) of the *Clean Energy Act*;

**"distribution equipment"** means posts, pipes, wires, transmission mains, distribution mains and other apparatus of a public utility used to supply service to the utility customers;

**"expenses"** includes expenses of the commission;

**"petroleum industry"** includes the carrying on within British Columbia of any of the following industries or businesses:

- (a) the distillation, refining or blending of petroleum;
- (b) the manufacture, refining, preparation or blending of products obtained from petroleum;
- (c) the storage of petroleum or petroleum products;
- (d) the wholesale or retail distribution or sale of petroleum products;
- (e) the wholesale or retail distribution or sale of liquefied or compressed natural gas;

**"petroleum products"** includes gasoline, naphtha, benzene, kerosene, lubricating oils, stove oil, fuel oil, furnace oil, paraffin, aviation fuels, liquid butane, liquid propane and other liquefied petroleum gas and all derivatives of petroleum and all products obtained from petroleum, whether or not blended with or added to other things;

**"public hearing"** means a hearing of which public notice is given, which is open to the public, and at which any person whom the commission determines to have an interest in the matter may be heard;

**"public utility"** means a person, or the person's lessee, trustee, receiver or liquidator, who owns or operates in British Columbia, equipment or facilities for

- (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or any other agent for the production of light, heat, cold or power to or for the public or a corporation for compensation, or
- (b) the conveyance or transmission of information, messages or communications by guided or unguided electromagnetic waves, including systems of cable, microwave, optical fibre or

radiocommunications if that service is offered to the public for compensation,

but does not include

- (c) a municipality or regional district in respect of services provided by the municipality or regional district within its own boundaries,
- (d) a person not otherwise a public utility who provides the service or commodity only to the person or the person's employees or tenants, if the service or commodity is not resold to or used by others,
- (e) a person not otherwise a public utility who is engaged in the petroleum industry or in the wellhead production of oil, natural gas or other natural petroleum substances,
- (f) a person not otherwise a public utility who is engaged in the production of a geothermal resource, as defined in the *Geothermal Resources Act*, or
- (g) a person, other than the authority, who enters into or is created by, under or in furtherance of an agreement designated under section 12 (9) of the *Hydro and Power Authority Act*, in respect of anything done, owned or operated under or in relation to that agreement;

**"rate"** includes

- (a) a general, individual or joint rate, fare, toll, charge, rental or other compensation of a public utility,
- (b) a rule, practice, measurement, classification or contract of a public utility or corporation relating to a rate, and
- (c) a schedule or tariff respecting a rate;

**"service"** includes

- (a) the use and accommodation provided by a public utility,
- (b) a product or commodity provided by a public utility, and
- (c) the plant, equipment, apparatus, appliances, property and facilities employed by or in connection with a public utility in providing service or a product or commodity for the purposes in which the public utility is engaged and for the use and accommodation of the public;

**"tenant"** does not include a lessee for a term of more than 5 years;

**"value"** or **"appraised value"** means the value determined by the commission.

(2) This Act does not apply to Powerex Corp.

## Part 1 — Utilities Commission

## Commission continued

- 2 (1) The British Columbia Utilities Commission is continued consisting of individuals appointed as follows by the Lieutenant Governor in Council after a merit-based process:
  - (a) one commissioner designated as the chair;
  - (b) other commissioners appointed after consultation with the chair.
- (2) The Lieutenant Governor in Council, after consultation with the chair, may designate a commissioner appointed under subsection (1) (b) as a deputy chair.
- (3) The chair may appoint a deputy chair or commissioner to act as chair for any purpose specified in the appointment.
- (4) [Repealed 2015-10-189.]
- (4.1) Section 47 (2) of the *Administrative Tribunals Act* applies to the commission respecting an order for costs under sections 117 and 118 of this Act.
- (5) The chair is the chief executive officer of the commission and has supervision over and direction of the work of the other commissioners and the chief operating officer.

## Application of *Administrative Tribunals Act*

- 2.1 The following provisions of the *Administrative Tribunals Act* apply to the commission, and, for that purpose, a reference in those provisions to a vice chair under that Act must be read as a reference to a deputy chair under this Act:
  - (a) Part 1 [*Interpretation and Application*];
  - (b) Part 2 [*Appointments*];
  - (c) Part 3 [*Clustering*];
  - (d) Part 4 [*Practice and Procedure*], except the following:
    - (i) section 14 [*general power to make orders*];
    - (ii) section 16 [*consent orders*];
    - (iii) section 17 [*withdrawal or settlement of application*];
    - (iv) section 22 [*notice of appeal (inclusive of prescribed fee)*];
    - (v) section 23 [*notice of appeal (exclusive of prescribed fee)*];
    - (vi) section 24 [*time limit for appeals*];
    - (vii) section 25 [*appeal does not operate as stay*];
    - (viii) section 26 [*organization of tribunal*];
    - (ix) section 27 [*staff of tribunal*];
    - (x) section 31 [*summary dismissal*];
    - (xi) section 34 (1) and (2) [*party power to compel witnesses and order disclosure*];
  - (e) section 44 [*tribunal without jurisdiction over constitutional questions*];

- (f) section 46.3 [*tribunal without jurisdiction to apply the Human Rights Code*];
- (g) section 48 [*maintenance of order at hearings*];
- (h) section 49 [*contempt proceeding for uncooperative witness or other person*];
- (i) section 54 [*enforcement of tribunal's final decision*];
- (j) section 56 [*immunity protection for tribunal and members*];
- (k) section 59.1 [*surveys*];
- (l) section 59.2 [*reporting*];
- (m) section 60 (1) (a), (b) and (g) to (i) and (2) [*power to make regulations*];
- (n) section 61 [*application of Freedom of Information and Protection of Privacy Act*].

### **Commission subject to direction**

- 3** (1) Subject to subsection (3), the Lieutenant Governor in Council, by regulation, may issue a direction to the commission with respect to the exercise of the powers and the performance of the duties of the commission, including, without limitation, a direction requiring the commission to exercise a power or perform a duty, or to refrain from doing either, as specified in the regulation.
- (2) The commission must comply with a direction issued under subsection (1), despite
- (a) any other provision of
    - (i) this Act, except subsection (3) of this section, or
    - (ii) the regulations,
  - (a.1) any provision of the *Clean Energy Act* or the regulations under that Act, or
  - (b) any previous decision of the commission.
- (3) The Lieutenant Governor in Council may not under subsection (1) specifically and expressly
- (a) declare an order or decision of the commission to be of no force or effect, or
  - (b) require the commission to rescind an order or a decision.

### **Sittings and divisions**

- 4** (1) The commission
- (a) must sit at the times and conduct its proceedings in a manner it considers convenient for the proper discharge and speedy dispatch of its duties under this Act.

- (b) [Repealed 2004-45-164.]
- (2) The chair may organize the commission into divisions.
- (3) The commissioners must sit
  - (a) as the commission, or
  - (b) as a division of the commission.
- (4) If commissioners sit as a division
  - (a) 2 or more divisions may sit at the same time,
  - (b) the division has all the jurisdiction of and may exercise and perform the powers and duties of the commission, and
  - (c) a decision or action of the division is a decision or action of the commission.
- (5) At a sitting of the commission or of a division of the commission, one commissioner is a quorum.
- (6) The chair may designate a commissioner to serve as chair at any sitting of the commission or a division of it.
- (7) If a proceeding is being held by the commission or by a division and a sitting commissioner is absent or unable to attend,
  - (a) that commissioner is thereafter disqualified from continuing to sit on the proceeding, and
  - (b) despite subsection (5), the commissioner or commissioners remaining present and sitting must exercise and perform all the jurisdiction, powers and duties of the commission.
- (8) and (9) [Repealed 2003-46-2.]
- (10) In the case of a tie vote at a sitting of the commission or a division of the commission, the decision of the chair of the commission or the division governs.
- (11) If a division is comprised of one member and that member is unable for any reason to complete the member's duties, the chair of the commission, with the consent of all parties to the application, may organize a new division to continue to hear and determine the matter on terms agreed to by the parties, and the vacancy does not invalidate the proceeding.

## **Commission's duties**

### **5 (0.1) [Repealed 2010-22-61.]**

- (1) On the request of the Lieutenant Governor in Council, it is the duty of the commission to advise the Lieutenant Governor in Council on any matter, whether or not it is a matter in respect of which the commission otherwise has jurisdiction.

(2) If, under subsection (1), the Lieutenant Governor in Council refers a matter to the commission, the Lieutenant Governor in Council may specify terms of reference requiring and empowering the commission to inquire into the matter.

(3) The commission may carry out a function or perform a duty delegated to it under an enactment of British Columbia or Canada.

(4) to (9) [Repealed 2010-22-61.]

## **Repealed**

6 [Repealed 2004-45-165.]

## **Employees**

7 (1) The commission

- (a) must employ a chief operating officer,
- (b) may employ a secretary and other officers and employees it considers necessary, and
- (c) may, subject to sections 9.1 and 10, determine the duties, the conditions of employment and the remuneration of the persons employed under paragraph (a) or (b) of this subsection.

(2) The *Public Service Act* does not apply to the employment of persons under subsection (1).

## **Technical consultants**

8 The commission may appoint or engage persons having special or technical knowledge necessary to assist the commission in carrying out its functions.

## **Pensions**

9 The Lieutenant Governor in Council may, by order, direct that the Public Service Pension Plan, continued under the *Public Sector Pension Plans Act*, applies to commissioners, officers and other employees of the commission, but the commission may, alone or in cooperation with other corporations, departments, commissions or other agencies of the Crown, establish, support or participate in any one or more of

- (a) a pension or superannuation plan, or
- (b) a group insurance plan

for the benefit of commissioners, officers and other employees of the commission and their dependants.

## **Chief operating officer's duties**

9.1 Subject to section 2 (5), the chief operating officer must

- (a) oversee the operations of the commission, and

- (b) supervise the work of the persons referred to in section 8 and the commission's employees.

### **Secretary's duties**

**10** (1) The secretary must

- (a) keep a record of the proceedings before the commission,
  - (b) ensure that every rule, regulation and order of the commission is filed in the records of the commission,
  - (c) have custody of all rules, regulations and orders made by the commission and all other records and documents of, or filed with, the commission, and
  - (d) carry out the instructions and directions of the commission under this Act respecting the secretary's duties or office.
- (2) On the application of a person who pays a prescribed fee, the secretary must deliver to the person a certified copy of any rule, regulation or order of the commission.
- (3) In the absence of the secretary, the duties of the secretary under this Act may be performed by another person appointed by the commission.
- (4) A rule, regulation and order of the commission must be signed by the chair, a deputy chair or an acting chair, and the original or a copy of it must be delivered to the secretary for filing.

### **Conflict of interest**

**11** (1) A commissioner or employee of the commission must not, directly or indirectly,

- (a) hold, acquire or have a beneficial interest in a share, stock, bond, debenture or other security of a corporation or other person subject to regulation under Part 3 of this Act,
  - (b) have a significant beneficial interest in a device, appliance, machine, article, patent or patented process, or a part of it, that is required or used by a corporation or other person referred to in paragraph (a) for the purpose of its equipment or service, or
  - (c) have a significant beneficial interest in a contract for the construction of works or the provision of a service for or by a corporation or other person referred to in paragraph (a).
- (2) A commissioner or employee of the commission, in whom a beneficial interest referred to in subsection (1) is or becomes vested, must divest the beneficial interest within 3 months after appointment to the commission or acquisition of the property, as the case may be.
- (3) The use or purchase for personal or domestic purposes, of gas, heat, light, power, electricity or petroleum products or service from a corporation or other

person subject to regulation under this Act is not a contravention of this section, and does not disqualify a commissioner or employee from acting in any matter affecting that corporation or other person.

### **Obligation to keep information confidential**

- 12** (1) Every commissioner and every officer and employee of the commission must keep secret all information coming to the person's knowledge during the course of the administration of this Act, except insofar as disclosure is necessary for the administration of this Act or insofar as the commission authorizes the person to release the information.
- (2) A commissioner, officer or employee of the commission must not be required to testify or produce evidence in any proceeding, other than a criminal proceeding, about records or information obtained in the discharge of duties under this Act.
- (3) Despite subsection (2), the Supreme Court may require the commission to produce the record of a proceeding that is the subject of an application for judicial review under the *Judicial Review Procedure Act*.

### **Annual report**

- 13** (1) In each year, the commission must make a report to the Lieutenant Governor in Council for the preceding fiscal year, setting out briefly
- (a) all applications and complaints to the commission under this Act and summaries of the commission's findings on them,
  - (b) other matters that the commission considers to be of public interest in connection with the discharge of its duties under this Act, and
  - (c) other information the Lieutenant Governor in Council directs.
- (2) The report must be laid before the Legislative Assembly as soon as possible after it is submitted to the Lieutenant Governor in Council.

## **Part 2**

### **Repealed**

**14-20** [Repealed 2003-46-5.]

## **Part 3 — Regulation of Public Utilities**

### **Application of this Part**

- 21** (1) This Part applies only to a public utility that is subject to the legislative authority of the Province.
- (2) The provision by a public utility of a class of service in respect of which the public utility is not subject to the legislative authority of the Province does not make this

Part inapplicable to that public utility in respect of any other class of service.

### **Provision of electricity service to listed facilities**

**21.1** (1) In this section, "listed purpose" means a purpose listed in subsection (2).

(2) The Lieutenant Governor in Council may make regulations respecting the provision by a public utility of electricity service for any of the following purposes:

- (a) to mine cryptocurrency;
- (b) to store or process electronic data, including electronic data used for artificial intelligence;
- (c) to produce hydrogen for use outside Canada.

(3) Without limiting subsection (2), the Lieutenant Governor in Council may make regulations as follows:

- (a) prohibiting, for a specified period or indefinitely, a public utility from supplying electricity service for a listed purpose;
- (b) setting a rate, or requiring the commission to set a rate, that does any of the following:
  - (i) establishes the charge to be paid for energy or capacity supplied for a listed purpose;
  - (ii) establishes limits on the amount of energy or capacity that may be supplied for a listed purpose;
  - (iii) establishes when electricity service may be supplied for a listed purpose;
  - (iv) establishes terms or conditions under which electricity service may be supplied for a listed purpose;
- (c) establishing a limit on the amount of energy or capacity that a public utility may make available for a listed purpose;
- (d) establishing a procedure or rules by which a public utility must select which persons are eligible to receive electricity service for a listed purpose;
- (e) without limiting paragraph (d),
  - (i) requiring a public utility to conduct a competitive process to select which persons are eligible to receive electricity service for a listed purpose and determine the charges to be paid in relation to that service, and
  - (ii) establishing criteria or rules for conducting the competitive process;
- (f) enabling a public utility to collect from its customers the costs it incurs or the revenue forecasted to be lost as a result of a regulation under this section;

- (g) defining "cryptocurrency" to include a specified digital medium of exchange, unit of account or store of value;
  - (h) defining "mine" to include or exclude a specified activity respecting cryptocurrency;
  - (i) establishing rules or criteria for determining whether hydrogen is produced for use outside Canada.
- (4) In making regulations under this section, the Lieutenant Governor in Council may do any of the following:
- (a) delegate a matter to the commission or a public utility;
  - (b) confer a discretion on the commission or a public utility;
  - (c) establish a procedure;
  - (d) make different regulations in relation to different facilities, persons, places, activities, circumstances or periods or different classes of facilities, persons, places, activities or circumstances.
- (5) A rate set under subsection (3) is deemed to be set by an order of the commission under section 58.
- (6) A regulation made under subsection (3)(f), insofar as it does not set a rate, is deemed to be an order of the commission under this Part.
- (7) A public utility or the commission, as applicable, must comply with a regulation made under this section despite
- (a) any other provision of this Act, except section 3,
  - (b) a regulation under this Act, except a direction under section 3, or
  - (c) any previous decision of the commission.
- (8) A regulation made under this section applies in relation to the provision of electricity service by a public utility despite
- (a) a regulation under section 22 made before the date this section comes into force, or
  - (b) an order under section 88 (3) made before the date this section comes into force.

## Exemptions

- 22 (1) In this section, "**minister**" means the minister responsible for the administration of the *Hydro and Power Authority Act*.
- (2) The minister, by regulation, may
- (a) exempt from any or all of section 71 and the provisions of this Part
    - (i) a public utility, or
    - (ii) a public utility in respect of any equipment, facility, plant, project, activity, contract, service or system of the public utility, and

- (b) in respect of an exemption made under paragraph (a), impose any terms and conditions the minister considers to be in the public interest.
- (3) The minister, before making a regulation under subsection (2), may refer the matter to the commission for a review.

### **General supervision of public utilities**

**23** (1) The commission has general supervision of all public utilities and may make orders about

- (a) equipment,
  - (b) appliances,
  - (c) safety devices,
  - (d) extension of works or systems,
  - (e) filing of rate schedules,
  - (f) reporting, and
  - (g) other matters it considers necessary or advisable for
    - (i) the safety, convenience or service of the public, or
    - (ii) the proper carrying out of this Act or of a contract, charter or franchise involving use of public property or rights.
- (2) Subject to this Act, the commission may make regulations requiring a public utility to conduct its operations in a way that does not unnecessarily interfere with, or cause unnecessary damage or inconvenience to, the public.

### **Commission must make examinations and inquiries**

**24** In its supervision of public utilities, the commission must make examinations and conduct inquiries necessary to keep itself informed about

- (a) the conduct of public utility business,
- (b) compliance by public utilities with this Act, regulations or any other law, and
- (c) any other matter in the commission's jurisdiction.

### **Commission may order improved service**

**25** If the commission, after a hearing held on its own motion or on complaint, finds that the service of a public utility is unreasonable, unsafe, inadequate or unreasonably discriminatory, the commission must

- (a) determine what is reasonable, safe, adequate and fair service, and
- (b) order the utility to provide it.

### **Commission may set standards**

- 26** After a hearing held on the commission's own motion or on complaint, the commission may do one or more of the following:
- (a) determine and set just and reasonable standards, classifications, rules, practices or service to be used by a public utility;
  - (b) determine and set adequate and reasonable standards for measuring quantity, quality, pressure, initial voltage or other conditions of supplying service;
  - (c) prescribe reasonable regulations for examining, testing or measuring a service;
  - (d) establish or approve reasonable standards for accuracy of meters and other measurement appliances;
  - (e) provide for the examination and testing of appliances used to measure a service of a utility.

### **Joint use of facilities**

**27** (1) If the commission, after a hearing, finds that

- (a) public convenience and necessity require the use by a public utility of conduits, subways, poles, wires or other equipment belonging to another public utility, and
- (b) the use will not prevent the owner or other users from performing their duties or result in any substantial detriment to their service,

the commission may, if the utilities fail to agree on the use, conditions or compensation, make an order it considers reasonable, directing that the use or joint use of the conduits, subways, poles, wires or other equipment be allowed and prescribing conditions of and compensation for the use.

(2) If the commission, after a hearing, finds that the provision of adequate service by one public utility or the safety of the persons operating or using that service requires that wires or cables carrying electricity and run, placed, erected, maintained or used by another public utility be placed, constructed or equipped with safety devices, the commission may make an order it considers reasonable about the placing, construction or equipment.

(3) By the same or a later order, the commission may

- (a) direct that the cost of the placing, construction or equipment be at the expense of the public utility whose wire, cable or apparatus was most recently placed, or
- (b) in the discretion of the commission, apportion the cost between the utilities.

### **Utility must provide service if supply line near**

- 28** (1) On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose.
- (2) Before supplying the service under subsection (1) or making a connection for the purpose, or as a condition of continuing to supply the service, the public utility may require the owner or occupier to give reasonable security for repayment of the costs of making the connection as set out in the filed schedule of rates.
- (2.1) If required to do so by regulation, the commission, in accordance with the prescribed requirements, must set a rate for the authority respecting the service provided under subsection (1).
- (2.2) A requirement prescribed for the purposes of subsection (2.1) applies despite
- (a) any other provision of this Act or any regulation under this Act, except for a regulation under section 3, or
  - (b) any previous decision of the commission.
- (3) After a hearing and for proper cause, the commission may relieve a public utility from the obligation to supply service under this Act on terms the commission considers proper and in the public interest.

#### **Commission may order utility to provide service if supply line distant**

- 29** On the application of a person whose premises are located more than 200 metres from a supply line suitable for that purpose, the commission may order a public utility that controls or operates the line
- (a) to supply, within the time the commission directs, the service required by that person, and
  - (b) to make extensions and install necessary equipment and apparatus on terms the commission directs, which terms may include payment of all or part of the cost by the applicant.

#### **Commission may order extension of existing service**

- 30** If the commission, after a hearing, determines that
- (a) an extension of the existing services of a public utility, in a general area that the public utility may properly be considered responsible for developing, is feasible and required in the public interest, and
  - (b) the construction and maintenance of the extension will not necessitate a substantial increase in rates chargeable, or a decrease in services provided, by the utility elsewhere,

the commission may order the utility to make the extension on terms the commission directs, which may include payment of all or part of the cost by the persons affected.

## **Regulation of agreements**

- 31** The commission may make rules governing conditions to be contained in agreements entered into by public utilities for their regulated services or for a class of regulated service.

## **Use of municipal thoroughfares**

- 32** (1) This section applies if a public utility
- (a) has the right to enter a municipality to place its distribution equipment on, along, across, over or under a public street, lane, square, park, public place, bridge, viaduct, subway or watercourse, and
  - (b) cannot come to an agreement with the municipality on the use of the street or other place or on the terms of the use.
- (2) On application and after any inquiry it considers advisable, the commission may, by order, allow the use of the street or other place by the public utility for that purpose and specify the manner and terms of use.

## **Dispensing with municipal consent**

- 33** (1) This section applies if a public utility
- (a) cannot agree with a municipality respecting placing its distribution equipment on, along, across, over or under a public street, lane, square, park, public place, bridge, viaduct, subway or watercourse in a municipality, and
  - (b) the public utility is otherwise unable, without expenditures that the commission considers unreasonable, to extend its system, line or apparatus from a place where it lawfully does business to another place where it is authorized to do business.
- (2) On application and after a hearing, for the purpose of that extension only and without unduly preventing the use of the street or other place by other persons, the commission may, by order,
- (a) allow the use of the street or other place by the public utility, despite any law or contract granting to another person exclusive rights, and
  - (b) specify the manner and terms of the use.

## **Order to extend service in municipality**

- 34** (1) On the complaint of a municipality that a public utility doing business in the municipality fails to extend its service to a part of the municipality, and after any hearing the commission considers advisable, the commission may order the public utility to extend its service in a way that the commission considers reasonable and proper.
- (2) An order under subsection (1) may

- (a) in the commission's discretion, impose terms for the extension, including the expenditure to be incurred for all necessary works, and
- (b) apportion the cost between the public utility, the municipality and consumers receiving service from the extension.

### **Other orders to extend service**

- 35** If the commission, after a hearing, concludes that in its opinion an extension by a public utility of its existing service would provide sufficient business to justify the construction and maintenance of the extension, and the financial condition of the public utility reasonably warrants the capital expenditure required, the commission may order the utility to extend its service to the extent the commission considers reasonable and proper.

### **Use of municipal structures**

- 36** Subject to any agreement between a public utility and a municipality and to the franchise or rights of the public utility, and after any hearing the commission considers advisable, the commission may, by order, specify the terms on which the public utility may use for any purpose of its service
- (a) a highway in the municipality, or
  - (b) a public bridge, viaduct or subway constructed or to be constructed by the municipality alone or jointly with another municipality, corporation or government.

### **Supervisors and inspectors**

- 37** (1) If the commission considers that a supervisor or inspector should be appointed to supervise or inspect, continuously or otherwise, the system, works, plant, equipment or service of a public utility with a view to establishing and carrying out measures for

- (a) the safety of the public and of the users of the utility's service, or
- (b) adequacy of service,

the commission may appoint a supervisor or inspector for that utility and may specify the person's duties.

- (2) The commission may

- (a) set the salary and expenses of a supervisor or inspector appointed under subsection (1), and
- (b) order the amount set
  - (i) to be borne by the municipality in which the operations of the public utility are carried on or its service is provided, or
  - (ii) to be borne or apportioned in a way the commission considers equitable.

## **Public utility must provide service**

**38** A public utility must

- (a) provide, and
- (b) maintain its property and equipment in a condition to enable it to provide,

a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

## **No discrimination or delay in service**

**39** On reasonable notice, a public utility must provide suitable service without undue discrimination or undue delay to all persons who

- (a) apply for service,
- (b) are reasonably entitled to it, and
- (c) pay or agree to pay the rates established for that service under this Act.

## **Exemption for part of municipality**

**40** (1) On application, the commission may, by order, exempt a municipality from section 39 except in a defined area.

(2) On application by any person and after notice to the municipality, the commission may enlarge or reduce an area defined under subsection (1).

## **No discontinuance without permission**

**41** A public utility that has been granted a certificate of public convenience and necessity or a franchise, or that has been deemed to have been granted a certificate of public convenience and necessity, and has begun any operation for which the certificate or franchise is necessary, or in respect of which the certificate is deemed to have been granted, must not cease the operation or a part of it without first obtaining the permission of the commission.

## **Duty to obey orders**

**42** A public utility must obey the lawful orders of the commission made under this Act for its business or service, and must do all things necessary to secure observance of those orders by its officers, agents and employees.

## **Duty to provide information**

**43** (1) A public utility must, for the purposes of this Act,

- (a) answer specifically all questions of the commission, and
- (b) provide to the commission
  - (i) the information the commission requires, and
  - (ii) a report, submitted annually and in the manner the commission requires, regarding the demand-side measures taken by the

public utility during the period addressed by the report, and the effectiveness of those measures.

(1.1) [Repealed 2010-22-64.]

- (2) A public utility that receives from the commission any form of return must fully and correctly answer each question in the return and deliver it to the commission.
- (3) On request by the commission, a public utility must deliver to the commission
  - (a) all profiles, contracts, reports of engineers, accounts and records in its possession or control relating in any way to its property or service or affecting its business, or verified copies of them, and
  - (b) complete inventories of the utility's property in the form the commission directs.
- (4) On request by the commission, a public utility must file with the commission a statement in writing setting out the name, title of office, post office address and the authority, powers and duties of
  - (a) every member of the board of directors and the executive committee,
  - (b) every trustee, superintendent, chief or head of construction or operation, or of any department, branch, division or line of construction or operation, and
  - (c) other officers of the utility.
- (5) The statement required under subsection (4) must be filed in a form that discloses the source and origin of each administrative act, rule, decision, order or other action of the utility.

### **Duty to keep records**

- 44** (1) A public utility must have in British Columbia an office in which it must keep all accounts and records required by the commission to be kept in British Columbia.
- (2) A public utility must not remove or permit to be removed from British Columbia an account or record required to be kept under subsection (1), except on conditions specified by the commission.

### **Long-term resource and conservation planning**

**44.1** (1) [Repealed 2010-22-65.]

- (2) Subject to subsection (2.1), a public utility must file with the commission, in the form and at the times the commission requires, a long-term resource plan including all of the following:
  - (a) an estimate of the demand for energy the public utility would expect to serve if the public utility does not take new demand-side measures during the period addressed by the plan;

- (b) a plan of how the public utility intends to reduce the demand referred to in paragraph (a) by taking cost-effective demand-side measures;
- (c) an estimate of the demand for energy that the public utility expects to serve after it has taken cost-effective demand-side measures;
- (d) a description of the facilities that the public utility intends to construct or extend in order to serve the estimated demand referred to in paragraph (c);
- (e) information regarding the energy purchases from other persons that the public utility intends to make in order to serve the estimated demand referred to in paragraph (c);
- (f) an explanation of why the demand for energy to be served by the facilities referred to in paragraph (d) and the purchases referred to in paragraph (e) are not planned to be replaced by demand-side measures;
- (g) any other information required by the commission.

(2.1) The authority need not file a long-term resource plan before February 28, 2021.

(3) The commission may exempt a public utility from the requirement to include in a long-term resource plan filed under subsection (2) any of the information referred to in paragraphs (a) to (f) of that subsection if the commission is satisfied that the information is not applicable with respect to the nature of the service provided by the public utility.

(4) [Repealed 2010-22-65.]

(5) The commission may establish a process to review long-term resource plans filed under subsection (2).

(6) After reviewing a long-term resource plan filed under subsection (2), the commission must

- (a) accept the plan, if the commission determines that carrying out the plan would be in the public interest, or
- (b) reject the plan.

(7) The commission may accept or reject, under subsection (6), a part of a public utility's plan, and, if the commission rejects a part of a plan,

- (a) the public utility may resubmit the part within a time specified by the commission, and
- (b) the commission may accept or reject, under subsection (6), the part resubmitted under paragraph (a) of this subsection.

(8) In determining under subsection (6) whether to accept a long-term resource plan, the commission must consider

- (a) the applicable of British Columbia's energy objectives,

- (b) the extent to which the plan is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
  - (c) whether the plan shows that the public utility intends to pursue adequate, cost-effective demand-side measures, and
  - (d) the interests of persons in British Columbia who receive or may receive service from the public utility.
- (9) In accepting under subsection (6) a long-term resource plan, or part of a plan, the commission may do one or both of the following:
- (a) order that a proposed utility plant or system, or extension of either, referred to in the accepted plan or the part is exempt from the operation of section 45 (1);
  - (b) order that, despite section 75, a matter the commission considers to be adequately addressed in the accepted plan or the part is to be considered as conclusively determined for the purposes of any hearing or proceeding to be conducted by the commission under this Act, other than a hearing or proceeding for the purposes of section 99.

## **Expenditure schedule**

- 44.2** (1) A public utility may file with the commission an expenditure schedule containing one or more of the following:
- (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
  - (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
  - (c) a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.
- (2) The commission may not consent under section 61 (2) to an amendment to or a rescission of a schedule filed under section 61 (1) to the extent that the amendment or the rescission is for the purpose of recovering expenditures referred to in subsection (1) (a) of this section, unless
- (a) the expenditure is the subject of a schedule filed and accepted under this section, or
  - (b) the amendment or rescission is for the purpose of setting an interim rate.
- (3) After reviewing an expenditure schedule submitted under subsection (1), the commission, subject to subsections (5), (5.1) and (6), must
- (a) accept the schedule, if the commission considers that making the expenditures referred to in the schedule would be in the public

interest, or

(b) reject the schedule.

(4) The commission may accept or reject, under subsection (3), a part of a schedule.

(5) In considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider

(a) the applicability of British Columbia's energy objectives,

(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

(c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,

(d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

(e) the interests of persons in British Columbia who receive or may receive service from the public utility.

(5.1) In considering whether to accept an expenditure schedule filed by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

(a) British Columbia's energy objectives,

(b) the most recent of the following documents:

(i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;

(ii) a long-term resource plan filed by the authority under section 44.1 of this Act,

(c) the extent to which the schedule is consistent with the requirements under section 19 of the *Clean Energy Act*, and

(d) if the schedule includes expenditures on demand-side measures, the extent to which the demand-side measures are cost-effective within the meaning prescribed by regulation, if any.

(6) If the commission considers that an expenditure in an expenditure schedule was determined to be in the public interest in the course of determining that a long-term resource plan was in the public interest under section 44.1 (6),

(a) subsection (5) of this section does not apply with respect to that expenditure, and

(b) the commission must accept under subsection (3) the expenditure in the expenditure schedule.

## **Certificate of public convenience and necessity**

- 45 (1) Except as otherwise provided, after September 11, 1980, a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the commission a certificate that public convenience and necessity require or will require the construction or operation.
- (2) For the purposes of subsection (1), a public utility that is operating a public utility plant or system on September 11, 1980 is deemed to have received a certificate of public convenience and necessity, authorizing it
- (a) to operate the plant or system, and
  - (b) subject to subsection (5), to construct and operate extensions to the plant or system.
- (3) Nothing in subsection (2) authorizes the construction or operation of an extension that is a reviewable project under the *Environmental Assessment Act*.
- (4) The commission may, by regulation, exclude a utility plant or categories of utility plants from the operation of subsection (1).
- (5) If it appears to the commission that a public utility should, before constructing or operating an extension to a utility plant or system, apply for a separate certificate of public convenience and necessity, the commission may, not later than 30 days after construction of the extension is begun, order that subsection (2) does not apply in respect of the construction or operation of the extension.
- (6) A public utility must file with the commission at least once each year a statement in a form prescribed by the commission of the extensions to its facilities that it plans to construct.

(6.1) and (6.2) [Repealed 2008-13-8.]

- (7) Except as otherwise provided, a privilege, concession or franchise granted to a public utility by a municipality or other public authority after September 11, 1980 is not valid unless approved by the commission.
- (8) The commission must not give its approval unless it determines that the privilege, concession or franchise proposed is necessary for the public convenience and properly conserves the public interest.
- (9) In giving its approval, the commission
- (a) must grant a certificate of public convenience and necessity, and
  - (b) may impose conditions about
    - (i) the duration and termination of the privilege, concession or franchise, or
    - (ii) construction, equipment, maintenance, rates or service,as the public convenience and interest reasonably require.

## **Procedure on application**

- 46 (1) An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes.
- (2) The commission has a discretion whether or not to hold any hearing on the application.
- (3) Subject to subsections (3.1) to (3.3), the commission may, by order, issue or refuse to issue the certificate, or may issue a certificate of public convenience and necessity for the construction or operation of a part only of the proposed facility, line, plant, system or extension, or for the partial exercise only of a right or privilege, and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.
- (3.1) In deciding whether to issue a certificate under subsection (3) applied for by a public utility other than the authority, the commission must consider
- (a) the applicable of British Columbia's energy objectives,
  - (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and
  - (c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*.
- (3.2) Section (3.1) does not apply if the commission considers that the matters addressed in the application for the certificate were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.
- (3.3) In deciding whether to issue a certificate under subsection (3) to the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider
- (a) British Columbia's energy objectives,
  - (b) the most recent of the following documents:
    - (i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;
    - (ii) a long-term resource plan filed by the authority under section 44.1 of this Act, and
  - (c) the extent to which the application for the certificate is consistent with the requirements under section 19 of the *Clean Energy Act*.
- (4) If a public utility desires to exercise a right or privilege under a consent, franchise, licence, permit, vote or other authority that it proposes to obtain but that has not, at the date of the application, been granted to it, the public utility

may apply to the commission for an order preliminary to the issue of the certificate.

- (5) On application under subsection (4), the commission may make an order declaring that it will, on application, under rules it specifies, issue the desired certificate, on the terms it designates in the order, after the public utility has obtained the proposed consent, franchise, licence, permit, vote or other authority.
- (6) On evidence satisfactory to the commission that the consent, franchise, licence, permit, vote or other authority has been secured, the commission must issue a certificate under section 45.
- (7) The commission may, by order, amend a certificate previously issued, or issue a new certificate, for the purpose of renewing, extending or consolidating a certificate previously issued.
- (8) A public utility to which a certificate is, or has been, issued, or to which an exemption is, or has been, granted under section 45 (4), is authorized, subject to this Act, to construct, maintain and operate the plant, system or extension authorized in the certificate or exemption.

#### **Order to cease work**

**47** (1) If a public utility

- (a) is engaged, or is about to engage, in the construction or operation of a plant or system, and
- (b) has not secured or has not been exempted from the requirement for, or is not deemed to have received a certificate of public convenience and necessity required under this Act,

any interested person may file a complaint with the commission.

- (2) The commission may, with or without notice, make an order requiring the public utility complained of to cease the construction or operation until the commission makes and files its decision on the complaint, or until further order of the commission.
- (3) The commission may, after a hearing, make the order and specify the terms under this Act that it considers advisable.
- (4) If the commission considers it necessary to determine whether a person is engaged or is about to engage in construction or operation of any plant or system, the commission may request that person to provide information required by it and to answer specifically all questions of the commission, and the person must comply.

#### **Cancellation or suspension of franchises and permits**

**48** (1) If the commission, after a hearing, determines that a public utility holding a franchise, licence or permit has failed to exercise or has not continued to

exercise or use the right and privilege granted by the franchise, licence or permit, the commission may

- (a) cancel the franchise, licence or permit, or
  - (b) suspend for a time the commission considers advisable the rights, or any of them, under the franchise, licence or permit.
- (2) If a franchise, licence or permit is cancelled, the utility must cease to operate.
- (3) If a right under a franchise, licence or permit is suspended, the utility must cease to exercise the suspended right during the period of suspension.

### **Accounts and reports**

**49** The commission may, by order, require every public utility to do one or more of the following:

- (a) keep the records and accounts of the conduct of the utility's business that the commission may specify, and for public utilities of the same class, adopt a uniform system of accounting specified by the commission;
- (b) provide, at the times and in the form and manner the commission specifies, a detailed report of finances and operations, verified as specified;
- (c) file with the commission, at the times and in the form and manner the commission specifies, a report of every accident occurring to or on the plant, equipment or other property of the utility, if the accident is of such nature as to endanger the safety, health or property of any person;
- (d) obtain from a board, tribunal, municipal or other body or official having jurisdiction or authority, permission, if necessary, to undertake or carry on a work or service ordered by the commission to be undertaken or carried on that is contingent on the permission.

### **Commission approval of issue of securities**

**50** (1) In this section, "**security**" means any share of any class of shares of a public utility or any bond, debenture, note or other obligation of a public utility whether secured or unsecured.

(2) Except in the case of a security evidencing indebtedness payable less than one year from its date, a public utility must not issue a security without first obtaining approval of the commission under this section and, if section 54 applies, under that section.

(3) Without first obtaining the commission's approval, a public utility must not,

- (a) in respect of a security that it has issued,
  - (i) increase a fixed dividend or fixed interest rate,

- (ii) alter a maturity date for the issue,
    - (iii) restrict the utility's right to redeem the issue,
    - (iv) increase the premium to be paid on redemption, or
    - (v) make a material alteration in the characteristics of the security,  
or
  - (b) purchase, redeem or otherwise acquire shares of any class of the utility except in accordance with any special rights or restrictions attached to them.
- (4) Subsections (2) and (3) do not apply to the issue of shares under a genuine employee share purchase plan or genuine employee share option plan that has been filed with the commission.
- (5) Without first obtaining the commission's approval, a public utility must not guarantee the payment of all or part of a loan or all or part of the interest on a loan made to another person.
- (6) A public utility is not liable under a guarantee given by it after June 29, 1988, in contravention of subsection (5) or of a condition of approval imposed under subsection (7).
- (7) The commission may give its approval under this section subject to conditions and requirements considered necessary or desirable in the public interest.
- (8) A municipality is not a utility for the purpose of this section.

### **Restraint on capitalization**

**51** A public utility must not do any of the following:

- (a) capitalize a franchise or right to be a corporation;
- (b) capitalize a franchise, licence, permit or concession in excess of the amount that, exclusive of tax or annual charge, is paid to the government, a municipality or other public authority as consideration for the franchise, licence, permit or concession;
- (c) issue a security or evidence of indebtedness against a contract for consolidation, amalgamation, merger or lease.

### **Restraint on disposition**

**52** (1) Except for a disposition of its property in the ordinary course of business, a public utility must not, without first obtaining the commission's approval,

- (a) dispose of or encumber the whole or a part of its property, franchises, licences, permits, concessions, privileges or rights, or
- (b) by any means, direct or indirect, merge, amalgamate or consolidate in whole or in part its property, franchises, licences, permits, concessions, privileges or rights with those of another person.

- (2) The commission may give its approval under this section subject to conditions and requirements considered necessary or desirable in the public interest.

### **Consolidation, amalgamation and merger**

**53** (1) A public utility must not consolidate, amalgamate or merge with another person

(a) unless the Lieutenant Governor in Council

(i) has first received from the commission a report under this section including an opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, and

(ii) has, by order, consented to the consolidation, amalgamation or merger, and

(b) except in accordance with an order made under paragraph (a).

(2) The Lieutenant Governor in Council may, in an order under subsection (1) (a), include conditions and requirements that the Lieutenant Governor in Council considers necessary or advisable.

(3) An application for consent of the Lieutenant Governor in Council under subsection (1) must be made to the commission by the public utility.

(4) The commission must inquire into the application and may for that purpose hold a hearing.

(5) On conclusion of its inquiry, the commission must,

(a) if it is of the opinion that the consolidation, amalgamation or merger would be beneficial in the public interest, submit its report and findings to the Lieutenant Governor in Council, or

(b) dismiss the application.

(6) If a public utility gives notice to its shareholders of a meeting of shareholders in connection with a consolidation, amalgamation or merger, it must

(a) set out in the notice the provisions of this section, and

(b) file a copy of the notice with the commission at the time of mailing to the shareholders.

### **Reviewable interests**

**54** (1) In this section:

**"child"** includes a child in respect of whom a person referred to in the definition of "spouse" stands in the place of a parent;

**"offeree"** means a person to whom a take over bid is made;

**"offeror"** means a person, other than an agent, who makes a take over bid and includes 2 or more persons

- (a) whose bids are made jointly or in concert, or
- (b) who intend to exercise jointly or in concert any voting rights attaching to the shares for which a take over bid is made;

**"spouse"** means a person who

- (a) is married to another person, or
- (b) is living with another person in a marriage-like relationship, and has lived in that relationship for a period of at least 2 years;

**"take over bid"** has the same meaning as in section 92 of the [Securities Act](#);

**"voting share"** means a share that has, or may under any special rights or restrictions attached to the share have, the right to vote for the election of directors, and for this purpose **"share"** includes

- (a) a security convertible into such a share, and
- (b) options and rights to acquire such a share or such a convertible security.

(2) For the purposes of this section, persons are associates if any of the following apply:

- (a) one of the persons is a corporation
  - (i) of which more than 10% of the shares outstanding of any class of the corporation are beneficially owned or controlled, directly or indirectly, by the other person, or
  - (ii) of which the other is a director or officer;
- (b) each of the persons is a corporation and
  - (i) more than 10% of the shares outstanding of any class of shares of one are beneficially owned or controlled, directly or indirectly, by the other, or
  - (ii) more than 10% of the shares outstanding of any class of shares of each are beneficially owned or controlled, directly or indirectly, by the same person;
- (c) they are partners or one is a partnership of which the other is a partner;
- (d) one is a trust in which the other has a substantial beneficial interest or for which the other serves as trustee or in a similar capacity;
- (e) they are obligated to act in concert in exercising a voting right in respect of shares of the utility;
- (f) one is the spouse or child of the other;
- (g) one is a relative of the other or of the other's spouse and has the same home as the other.

- (3) For the purpose of subsection (2), if a person has more than one associate, those associates are associates of each other.
- (4) For the purpose of this section, a person has a reviewable interest in a public utility if
- (a) the person owns or controls, or
  - (b) the person and the person's associates own or control,
- in the aggregate more than 20% of the voting shares outstanding of any class of shares of the utility.
- (5) A public utility must not, without the approval of the commission,
- (a) issue, sell, purchase or register on its books a transfer of shares in the capital of the utility or create, or
  - (b) attach to any shares, whether issued or unissued, any special rights or restrictions,
- if the issue, sale, purchase or registration or the creation or attachment of the special rights or restrictions would
- (c) cause any person to have a reviewable interest,
  - (d) increase the percentage of voting shares owned by a person who has a reviewable interest,
  - (e) be a registration of a transfer of shares, the acquisition of which was contrary to subsection (7) or (8), or
  - (f) increase the voting rights attached to any shares owned by a person who has a reviewable interest.
- (6) Failure of a public utility to comply with subsection (5) does not give rise to an offence if the public utility acts in the genuine belief based on an enquiry made with reasonable care, that the issue, sale, purchase or registration, or the creation or attachment of the special rights or restrictions, would not have the effects referred to in subsection (5) (c) to (f).
- (7) A person must not acquire or acquire control of such numbers of any class of shares of a public utility as
- (a) in themselves, or
  - (b) together with shares already owned or controlled by the person and the person's associates,
- cause the person to have a reviewable interest in a public utility unless the person has obtained the commission's approval.
- (8) Except if the acquisition or acquisition of control does not increase the percentage of voting shares held, owned or controlled by the person or by the person and the person's associates, a person having a reviewable interest in a public utility and any associate of that person must not acquire or acquire control

of any voting shares in the public utility unless the person or associate has obtained the commission's approval.

- (9) The commission may give its approval under this section subject to conditions and requirements it considers necessary or desirable in the public interest, but the commission must not give its approval under this section unless it considers that the public utility and the users of the service of the public utility will not be detrimentally affected.
- (10) If the commission determines that there has been a contravention of subsection (5), (7) or (8), the commission may, on notice to the public utility and after a hearing, make an order imposing on the public utility conditions and requirements respecting the management and operation of the utility.
- (11) A proceeding must not be brought against the commission or the government by reason of the exercise by the commission of its powers under subsection (9) or (10).
- (12) An offeror who makes a take over bid for shares of a public utility must
- (a) file with the commission a copy of the take over bid and all supporting or supplementary material within 5 days after the date the material is first sent to offerees, and
  - (b) include in or attach to the take over bid a notice setting out the provisions of this section and stating the number, without duplication, and designation of any shares of the public utility held by the offeror and the offeror's associates.
- (13) Nothing in subsection (12) relieves a person from any requirement under the *Securities Act*.

### **Appraisal of utility property**

**55** (1) The commission may

- (a) ascertain by appraisal the value of the property of a public utility, and
  - (b) inquire into every fact that, in its judgment, has a bearing on that value, including the amount of money actually and reasonably expended in the undertaking to provide service reasonably adequate to the requirements of the community served by the utility as that community exists at the time of the appraisal.
- (2) In making its appraisal, the commission must have access to all records in the possession of a municipality or any ministry or board of the government.
- (3) In making its appraisal under this section, the commission may order
- (a) that all or part of the costs and expenses of the commission in making the appraisal must be paid by the public utility, and
  - (b) that the utility pay an amount as the work of appraisal proceeds.

- (4) The certificate of the chair of the commission is conclusive evidence of the amounts payable under subsection (3).
- (5) Expenses approved by the commission in connection with an appraisal, including expenses incurred by the public utility whose property is appraised, must be charged by the utility to the cost of operating the property as a current item of expense, and the commission may, by order, authorize or require the utility to amortize this charge over a period and in the manner the commission specifies.

### **Depreciation accounts and funds**

- 56** (1) If the commission, after inquiry, considers that it is necessary and reasonable that a depreciation account should be carried by a public utility, the commission may, by order, require the utility to keep an adequate depreciation account under rules and forms of account specified by the commission.
- (2) The commission must determine and, by order after a hearing, set proper and adequate rates of depreciation.
  - (3) The rates must be set so as to provide, in addition to the expense of maintenance, the amounts required to keep the public utility's property in a state of efficiency in accordance with technical and engineering progress in that industry of the utility.
  - (4) A public utility must adjust its depreciation accounts to conform to the rates set by the commission and, if ordered by the commission, must set aside out of earnings whatever money is required and carry it in a depreciation fund.
  - (5) Without the consent of the commission, the depreciation fund must not be expended other than for replacement, improvement, new construction, extension or addition to the property of the utility.

### **Reserve funds**

- 57** (1) The commission may, by order, require a public utility to create and maintain a reserve fund for any purpose the commission considers proper, and may set the amount or rate to be charged each year in the accounts of the utility for the purpose of creating the reserve fund.
- (2) The commission may order that no reserve fund other than that created and maintained as directed by the commission may be created by a public utility.

### **Commission may order amendment of schedules**

- 58** (1) The commission may,
- (a) on its own motion, or
  - (b) on complaint by a public utility or other interested person that the existing rates in effect and collected or any rates charged or attempted to be charged for service by a public utility are unjust, unreasonable,

insufficient, unduly discriminatory or in contravention of this Act, the regulations or any other law,

after a hearing, determine the just, reasonable and sufficient rates to be observed and in force.

(2) If the commission makes a determination under subsection (1), it must, by order, set the rates.

(2.1) The commission must set rates for the authority in accordance with

(a) [Repealed RS1996-473-58 (2.3).]

(b) the prescribed factors and guidelines, if any.

(2.2) [Repealed RS1996-473-58 (2.3).]

(2.3) Subsections (2.1) (a) and (2.2) are repealed on March 31, 2010.

(2.4) Despite subsection (2.3), a requirement prescribed for the purposes of subsection (2.1) (a) that is in effect immediately before March 31, 2010, continues to apply after that date as though subsection (2.2) were still in force, unless the prescribed requirement is amended or repealed after that date.

(3) The public utility affected by an order under this section must

(a) amend its schedules in conformity with the order, and

(b) file amended schedules with the commission.

### **Rate rebalancing**

**58.1** (1) In this section, "**revenue-cost ratio**" means the amount determined by dividing a public utility's revenues from a class of customers during a period of time by the public utility's costs to serve that class of customers during the same period of time.

(2) This section applies despite

(a) any other provision of

(i) this Act, or

(ii) the regulations, except a regulation under section 3, or

(b) any previous decision of the commission.

(3) [Repealed 2019-24-14.]

(4) [Repealed RS1996-473-58.1 (5).]

(5) and (6) [Repealed 2019-24-14.]

(7) The commission may not set rates for a public utility for the purpose of changing the revenue-cost ratio for a class of customers except on application by the public utility.

### **Discrimination in rates**

- 59** (1) A public utility must not make, demand or receive
- (a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or
  - (b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.
- (2) A public utility must not
- (a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or
  - (b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.
- (3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).
- (4) It is a question of fact, of which the commission is the sole judge,
- (a) whether a rate is unjust or unreasonable,
  - (b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or
  - (c) whether a service is offered or provided under substantially similar circumstances and conditions.
- (5) In this section, a rate is "unjust" or "unreasonable" if the rate is
- (a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,
  - (b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or
  - (c) unjust and unreasonable for any other reason.

### **Setting of rates**

- 60** (1) In setting a rate under this Act
- (a) the commission must consider all matters that it considers proper and relevant affecting the rate,
  - (b) the commission must have due regard to the setting of a rate that
    - (i) is not unjust or unreasonable within the meaning of section 59,
    - (ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and
    - (iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

- (b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and
- (c) if the public utility provides more than one class of service, the commission must
  - (i) segregate the various kinds of service into distinct classes of service,
  - (ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and
  - (iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates set for any other unit.
- (2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.
- (3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.
- (4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

### **Rate schedules to be filed with commission**

- 61** (1) A public utility must file with the commission, under rules the commission specifies and within the time and in the form required by the commission, schedules showing all rates established by it and collected, charged or enforced or to be collected or enforced.
- (2) A schedule filed under subsection (1) must not be rescinded or amended without the commission's consent.
- (3) The rates in schedules as filed and as amended in accordance with this Act and the regulations are the only lawful, enforceable and collectable rates of the public utility filing them, and no other rate may be collected, charged or enforced.

- (4) A public utility may file with the commission a new schedule of rates that the utility considers to be made necessary by a change in the price, over which the utility has no effective control, required to be paid by the public utility for its gas supplies, other energy supplied to it, or expenses and taxes, and the new schedule may be put into effect by the public utility on receiving the approval of the commission.
- (5) Within 60 days after the date it approves a new schedule under subsection (4), the commission may,
- (a) on complaint of a person whose interests are affected, or
  - (b) on its own motion,
- direct an inquiry into the new schedule of rates having regard to the setting of a rate that is not unjust or unreasonable.
- (6) After an inquiry under subsection (5), the commission may
- (a) rescind or vary the increase and order a refund or customer credit by the utility of all or part of the money received by way of increase, or
  - (b) confirm the increase or part of it.

### **Schedules must be available to public**

- 62** A public utility must keep a copy of the schedules filed open to and available for public inspection under commission rules.

### **Schedules must be observed**

- 63** A public utility must not, without the consent of the commission, directly or indirectly, in any way charge, demand, collect or receive from any person for a regulated service provided by it, or to be provided by it, compensation that is greater than, less than or other than that specified in the subsisting schedules of the utility applicable to that service and filed under this Act.

### **Orders respecting contracts**

- 64** (1) If the commission, after a hearing, finds that under a contract entered into by a public utility a person receives a regulated service at rates that are unduly preferential or discriminatory, the commission may
- (a) declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then unenforceable to the extent specified, or
  - (b) make any other order it considers advisable in the circumstances.
- (2) If a contract is declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section.

## Part 3.1

### Repealed

64.01- [Repealed 2010-22-69.]

64.04

## Part 4 — Carriers, Purchasers and Processors

### Definition

**64.1** In this Part, "**sufficient notice**" means notice in the manner and form, within the period, with the content and by the person required by the commission.

### Common carrier

- 65** (1) In this section, "**common carrier**" means a person declared to be a common carrier by the commission under subsection (2) (a).
- (2) On application by an interested person and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, the commission may
- (a) issue an order, to be effective on a date determined by it, declaring a person who owns or operates a pipeline for the transportation of
    - (i) one or more of crude oil, natural gas and natural gas liquids, or
    - (ii) any other type of energy resource prescribed by the Lieutenant Governor in Council,to be a common carrier with respect to the operation of the pipeline, and
  - (b) in the order establish the conditions under which the common carrier must accept and carry energy resources.
- (3) On application by a person that uses or seeks to use facilities operated by a common carrier, the commission, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, may establish the conditions under which the common carrier must accept and carry crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a).
- (3.1) Without limiting subsection (2) (b) or (3), the commission may establish conditions with respect to a common carrier in relation to any of the following matters:
- (a) a toll that may be charged by the common carrier;
  - (b) extensions, improvements or abandonment of service.
- (3.2) The commission may order that section 43 applies with respect to a common carrier as though the common carrier were a public utility referred to in that section.

- (4) A common carrier must not unreasonably discriminate
  - (a) between itself and persons who apply to the common carrier to transport, in its pipeline, crude oil, natural gas, natural gas liquids or prescribed energy resources referred to in subsection (2) (a) (ii), or
  - (b) among the persons who so apply.
- (5) A common carrier must comply with the conditions in any order applicable to the common carrier that is made under this section.
- (6) The commission may, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary an order made under this section.
- (7) If an agreement between a common carrier and another person
  - (a) is made before an order is made under this section, and
  - (b) is inconsistent with the conditions established by the commission in an order made under this section,the commission may, in the order or in a subsequent order, after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary the agreement between the parties to eliminate the inconsistency.
- (8) Subject to subsection (9), if an agreement is varied under subsection (7), the common carrier and the commission are not liable for damages suffered as a result of that variation by the other party to the agreement.
- (9) Subsection (8) does not apply to a common carrier referred to in that subsection in relation to anything done or omitted by that person in bad faith.

### **Common purchaser**

- 66** (1) In this section, "**common purchaser**" means a person declared to be a common purchaser by the commission under subsection (2).
- (2) On application by an interested person and after a hearing, sufficient notice of which has been given to persons the commission believes may be affected, the commission may issue an order, to be effective on a date determined by it, declaring a person who purchases or otherwise acquires, from a pool designated by the commission, crude oil, natural gas or natural gas liquids to be a common purchaser of the crude oil, natural gas or natural gas liquids.
  - (3) On application by a person whose crude oil, natural gas or natural gas liquids is or will be purchased by a common purchaser, the commission, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, may establish the conditions under which the common purchaser must purchase crude oil, natural gas or natural gas liquid.
  - (4) A common purchaser must not unreasonably discriminate

- (a) between itself and persons who apply for the services offered by the common purchaser, or
  - (b) among the persons who so apply.
- (5) A common purchaser must comply with the conditions in any order applicable to the common purchaser that is made under this section.
- (6) The commission may, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary an order made under this section.
- (7) If an agreement between a common purchaser and another person
  - (a) is made before an order is made under this section, and
  - (b) is inconsistent with the conditions established by the commission in an order made under this section,the commission may, in the order or in a subsequent order, after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary the agreement between the parties to eliminate the inconsistency.
- (8) Subject to subsection (9), if an agreement is varied under subsection (7), the common purchaser and the commission are not liable for damages suffered as a result of that variation by the other party to the agreement.
- (9) Subsection (8) does not apply to a common purchaser referred to in that subsection in relation to anything done or omitted by that person in bad faith.

### **Common processor**

- 67** (1) In this section, "**common processor**" means a person declared to be a common processor by the commission under subsection (2).
- (2) On application by an interested person and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, the commission may issue an order, to be effective on a date determined by it, declaring the person that owns or operates a plant for processing natural gas to be a common processor of natural gas.
  - (3) On application by a person that uses or seeks to use facilities operated by a common processor, the commission, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, may establish the conditions under which the common processor must accept and process natural gas.
  - (4) A common processor must not unreasonably discriminate
    - (a) between itself and persons who apply for the services offered by the common processor, or
    - (b) among the persons who so apply.

- (5) A common processor must comply with the conditions in any order applicable to the common processor made under this section.
- (6) The commission may, by order and after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary an order made under this section.
- (7) If an agreement between a common processor and another person
- (a) is made before an order is made under this section, and
  - (b) is inconsistent with the conditions established by the commission in an order made under this section,
- the commission may, in the order or a subsequent order, after a hearing, sufficient notice of which has been given to all persons the commission believes may be affected, vary the agreement between the parties to eliminate the inconsistency.
- (8) Subject to subsection (9), if an agreement is varied under subsection (7), the common processor and the commission are not liable for damages suffered as a result of that variation by the other party to the agreement.
- (9) Subsection (8) does not apply to a common processor referred to in that subsection in relation to anything done or omitted by that person in bad faith.

## Part 5 — Electricity Transmission

### Definitions

68 In this Part:

**"electricity transmission facilities"** means conductors, circuits, transmission towers, substations, switching stations, transformers and any other equipment or facilities that are necessary for the purpose of transmitting electricity;

**"energy"** means electricity or natural gas;

**"energy supply contract"** means a contract under which energy is sold by a seller to a public utility or another buyer, and includes an amendment of that contract, but does not include a contract in respect of which a schedule is approved under section 61 of this Act;

**"gas marketer"** means a person who holds a gas marketer licence issued under section 71.1 (6) (a);

**"low-volume consumer"** has the meaning ascribed to it under rules made by the commission under section 71.1 (10);

**"natural gas"** means any methane, propane or butane that is sold for consumption as a domestic, commercial or industrial fuel or as an industrial raw material;

**"public utility"** means a public utility to which Part 3 applies;

"seller" means a person who sells or trades in energy.

## Repealed

69 [Repealed 2003-46-10.]

## Use of electricity transmission facilities

- 70** (1) On application and after a hearing, the commission may make an order directing a public utility to allow a person, other than a public utility, to use the electricity transmission facilities of the public utility if the commission finds that
- (a) the person and the public utility have failed to agree on the use of the facilities or on the conditions or compensation for their use,
  - (b) the use of the facilities will not prevent the public utility or other users from performing their duties or result in any substantial detriment to their service, and
  - (c) the public interest requires the use of the facilities by the person.
- (2) An order under subsection (1) may contain terms and conditions the commission considers advisable, including terms and conditions respecting the rates payable to the public utility for the use of its electricity transmission facilities.
- (3) After a hearing, the commission may, by order, vary or rescind an order made under this section.
- (4) Any interested person may apply to the commission for an order under this section, and the application must contain the information the commission specifies.

## Energy supply contracts

- 71** (1) Subject to subsection (1.1), a person who, after this section comes into force, enters into an energy supply contract must
- (a) file a copy of the contract with the commission under rules and within the time it specifies, and
  - (b) provide to the commission any information it considers necessary to determine whether the contract is in the public interest.
- (1.1) Subsection (1) does not apply to an energy supply contract for the sale of natural gas unless the sale is to a public utility.
- (2) The commission may make an order under subsection (3) if the commission, after a hearing, determines that an energy supply contract to which subsection (1) applies is not in the public interest.
- (2.1) In determining under subsection (2) whether an energy supply contract filed by a public utility other than the authority is in the public interest, the commission must consider
- (a) the applicable of British Columbia's energy objectives,

- (b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,
- (c) the extent to which the energy supply contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*,
- (d) the interests of persons in British Columbia who receive or may receive service from the public utility,
- (e) the quantity of the energy to be supplied under the contract,
- (f) the availability of supplies of the energy referred to in paragraph (e),
- (g) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (e), and
- (h) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (e).

(2.2) Subsection (2.1) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.21) In determining under subsection (2) whether an energy supply contract filed by the authority is in the public interest, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

- (a) British Columbia's energy objectives,
- (b) the most recent of the following documents:
  - (i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;
  - (ii) a long-term resource plan filed by the authority under section 44.1 of this Act,
- (c) the extent to which the energy supply contract is consistent with the requirements under section 19 of the *Clean Energy Act*,
- (d) the quantity of the energy to be supplied under the contract,
- (e) the availability of supplies of the energy referred to in paragraph (d),
- (f) the price and availability of any other form of energy that could be used instead of the energy referred to in paragraph (d), and
- (g) in the case only of an energy supply contract that is entered into by a public utility, the price of the energy referred to in paragraph (d).

(2.22) Subsection (2.21) (a) to (c) does not apply if the commission considers that the matters addressed in the energy supply contract filed by the authority under subsection (1) were determined to be in the public interest in the course of considering a long-term resource plan under section 44.1.

(2.3) A public utility may submit to the commission a proposed energy supply contract setting out the terms and conditions of the contract and a process the public utility intends to use to acquire power from other persons in accordance with those terms and conditions.

(2.4) If satisfied that it is in the public interest to do so, the commission, by order, may approve a proposed contract submitted under subsection (2.3) and a process referred to in that subsection.

(2.5) In considering the public interest under subsection (2.4) with respect to a submission by a public utility other than the authority, the commission must consider

- (a) the applicability of British Columbia's energy objectives,
- (b) the most recent long-term resource plan filed by the public utility under section 44.1,
- (c) the extent to which the application for the proposed contract is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act*, and
- (d) the interests of persons in British Columbia who receive or may receive service from the public utility.

(2.51) In considering the public interest under subsection (2.4) with respect to a submission by the authority, the commission, in addition to considering the interests of persons in British Columbia who receive or may receive service from the authority, must consider

- (a) British Columbia's energy objectives,
- (b) the most recent of the following documents:
  - (i) an integrated resource plan approved under section 4 of the *Clean Energy Act* before the repeal of that section;
  - (ii) a long-term resource plan filed by the authority under section 44.1 of this Act, and
- (c) the extent to which the application for the proposed contract is consistent with the requirements under section 19 of the *Clean Energy Act*.

(2.6) If the commission issues an order under subsection (2.4), the commission may not issue an order under subsection (3) with respect to a contract

- (a) entered into exclusively on the terms and conditions, and
- (b) as a result of the process

referred to in subsection (2.3).

(3) If subsection (2) applies, the commission may

- (a) by order, declare the contract unenforceable, either wholly or to the extent the commission considers proper, and the contract is then

unenforceable to the extent specified, or

(b) make any other order it considers advisable in the circumstances.

- (4) If an energy supply contract is, under subsection (3) (a), declared unenforceable either wholly or in part, the commission may order that rights accrued before the date of the order under that subsection be preserved, and those rights may then be enforced as fully as if no proceedings had been taken under this section.
- (5) An energy supply contract or other information filed with the commission under this section must be made available to the public unless the commission considers that disclosure is not in the public interest.

## **Gas marketers**

- 71.1** (1) A person must not perform a gas marketing activity within the meaning of subsection (2) unless
- (a) the person is a public utility and the public utility performs the gas marketing activity within any area in which it is authorized to provide service, or
  - (b) the person holds a gas marketer licence issued to the person under subsection (6) (a).
- (2) For the purposes of subsection (1), a person performs a gas marketing activity if the person
- (a) sells or offers to sell natural gas to a low-volume consumer,
  - (b) acts as the agent or broker for a seller in a sale of natural gas to a low-volume consumer, or
  - (c) acts or offers to act as the agent or broker of a low-volume consumer in a purchase of natural gas.
- (3) A gas marketer must comply with the commission rules issued under subsection (10) and the terms and conditions, if any, attached to the gas marketer licence held by the gas marketer.
- (4) A gas marketer must not carry on or offer to carry on business as a gas marketer in a name other than the name in which it is licensed unless authorized to do so in the licence.
- (5) If a person is not in compliance with subsection (1), (3) or (4), the commission may do one or more of the following:
- (a) declare an energy supply contract between the person and a low-volume consumer unenforceable, either wholly or to the extent the commission considers proper, in which event the contract is enforceable to the extent specified;
  - (b) if the person is a gas marketer,
    - (i) amend the terms and conditions of, or impose new terms and conditions on, the gas marketer licence, and

(ii) suspend or cancel the gas marketer licence.

(5.1) If the commission, under subsection (5) (a), declares an energy supply contract to be unenforceable, either wholly or in part, the commission may also order the person to pay to the low-volume consumer some or all of the money paid under the contract by the low-volume consumer.

(6) The commission may

- (a) on application, issue a gas marketer licence to any person who is not a public utility,
- (b) impose, in respect of any gas marketer licence issued by the commission, terms and conditions that the commission considers appropriate,
- (c) amend any of the terms and conditions imposed in respect of a gas marketer licence, and
- (d) suspend or cancel a gas marketer licence.

(7) The commission may require, as a condition of granting a gas marketer licence, that the gas marketer post security in a form, and in accordance with such terms and conditions, as the commission considers appropriate.

(8) The commission may order that some or all of the security posted by a gas marketer in accordance with a requirement imposed under subsection (7) be paid out to those persons who the commission considers have been or may be affected by an act or omission of the gas marketer.

(9) Sections 42 and 43 apply to each gas marketer as if that gas marketer were a public utility.

(10) The commission may make the following rules:

- (a) defining "low-volume consumer";
- (b) respecting the process by which application may be made for a gas marketer licence and specifying the form and content of applications for that licence;
- (c) respecting the imposition of terms and conditions on gas marketer licences;
- (d) requiring an applicant for a gas marketer licence to obtain a bond, letter of credit or other specified security and requiring the filing with the commission of proof, satisfactory to the commission, of that security;
- (e) respecting the form and content of security that may be required under paragraph (d) and the person by whom and the terms on which it is to be held;
- (f) respecting the circumstances in which and the persons to whom disbursement of some or all of the security required under paragraph

(d) is to be made.

## **Part 6 — Commission Jurisdiction**

### **Jurisdiction of commission to deal with applications**

- 72** (1) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, complaining that a person constructing, maintaining, operating or controlling a public utility service or charged with a duty or power relating to that service, has done, is doing or has failed to do anything required by this Act or another general or special Act, or by a regulation, order, bylaw or direction made under any of them.
- (2) The commission has jurisdiction to inquire into, hear and determine an application by or on behalf of any party interested, requesting the commission to
- (a) give a direction or approval which by law it may give, or
  - (b) approve, prohibit or require anything to which by any general or special Act, the commission's jurisdiction extends.

### **Mandatory and restraining orders**

- 73** (1) The commission may order and require a person to do immediately or by a specified time and in the way ordered, so far as is not inconsistent with this Act, the regulations or another Act, anything that the person is or may be required or authorized to do under this Act or any other general or special Act and to which the commission's jurisdiction extends.
- (2) The commission may forbid and restrain the doing or continuing of anything contrary to or which may be forbidden or restrained under any Act, general or special, to which the commission's jurisdiction extends.

### **Inspections**

- 74** For the purposes of this Act, a person authorized in writing by the commission may
- (a) enter on and inspect property, and
  - (a.1) inspect and make copies of records.
  - (b) [Repealed 2012-27-33.]

### **Commission not bound by precedent**

- 75** The commission must make its decision on the merits and justice of the case, and is not bound to follow its own decisions.

### **Jurisdiction as to liquidators and receivers**

- 76** (1) The fact that a liquidator, receiver, manager or other official of a public utility, or other person engaged in the petroleum industry, or a person seizing a public utility's property has been appointed by a court in British Columbia, or is acting

under the authority of a court, does not prevent the exercise by the commission of any jurisdiction conferred by this Act.

- (2) A liquidator, receiver, manager, official or person seizing must act in accordance with this Act and the orders and directions of the commission, whether the orders are general or particular.
- (3) The liquidator or other person referred to in subsection (1), and any person acting under that person, must obey the orders of the commission, within its jurisdiction, and the commission may enforce its orders against the person even though the person is appointed by or acts under the authority of a court.

### **Power to extend time**

- 77** If a work, act, matter or thing is, by order or decision of the commission, required to be performed or completed within a specified time, the commission may, if the circumstances of the case in its opinion so require, extend the time so specified
- (a) on notice and hearing, or
  - (b) in its discretion, on application, without notice to any person.

### **Evidence**

- 78** (1) [Repealed 2004-45-169.]
- (2) An inquiry that the commission considers necessary may be made by a member or officer or by a person appointed by the commission to make the inquiry, and the commission may act on that person's report.
  - (3) Each member, officer and person appointed has, for the purpose of the inquiry, the powers referred to in section 74 of this Act and section 34 (3) and (4) of the *Administrative Tribunals Act*.
  - (4) If a person is appointed to inquire and report on a matter, the commission may order by whom, and in what proportion, the costs incurred must be paid, and may set the amount of the costs.

### **Findings of fact conclusive**

- 79** The determination of the commission on a question of fact in its jurisdiction, or whether a person is or is not a party interested within the meaning of this Act, is binding and conclusive on all persons and all courts.

### **Commission not bound by judicial acts**

- 80** In determining a question of fact, the commission is not bound by the finding or order of a court in a proceeding involving the determination of that fact, and the finding or order is, before the commission, evidence only.

### **Pending litigation**

- 81** The fact that a suit, prosecution or other proceeding in a court involving questions of fact is pending does not deprive the commission of jurisdiction to hear and

determine the same questions of fact.

### **Power to inquire without application**

**82** (1) The commission

(a) may, on its own motion, and

(b) must, on the request of the Lieutenant Governor in Council,

inquire into, hear and determine a matter that under this Act it may inquire into, hear or determine on application or complaint.

(2) For the purpose of subsection (1), the commission has the same powers as are vested in it by this Act in respect of an application or complaint.

### **Action on complaints**

**83** If a complaint is made to the commission, the commission has powers to determine whether a hearing or inquiry is to be had, and generally whether any action on its part is or is not to be taken.

### **General powers not limited**

**84** The enumeration in this Act of a specific commission power or authority does not exclude or limit other powers or authorities given to the commission.

### **Hearings to be held in certain cases**

**85** (1) Except in case of urgency, of which the commission is sole judge, the commission must not, without a hearing, make an order involving an outlay, loss or deprivation to a public utility.

(2) If an order is made in case of urgency without a hearing, on the application of a person interested, the commission must as soon as practicable hear and reconsider the matter and make any further order it considers advisable.

### **Public hearing**

**86** If this Act requires that a hearing be held, it must be a public hearing whenever, in the opinion of the commission or the Lieutenant Governor in Council, a public hearing is in the public interest.

### **Repealed**

**86.1** [Repealed 2004-45-170.]

### **When oral hearings not required**

**86.2** (1) Despite any other provision of this Act, in any circumstance in which, under this Act, a hearing may or must be held, the commission may conduct a written hearing.

(2) The commission may make rules respecting the circumstances in which and the process by which written hearings may be conducted and specifying the form

and content of materials to be provided for written hearings.

### **Recitals not required in orders**

**87** In making an order, the commission is not required to recite or show on the face of the order the taking of any proceeding, the giving of any notice or the existence of any circumstance necessary to give the commission jurisdiction.

### **Application of orders**

- 88** (1) In making an order, rule or regulation, the commission may make it apply to all cases, or to a particular case or class of cases, or to a particular person.
- (2) The commission may exempt a person from the operation of an order, rule or regulation made under this Act for a time the commission considers advisable.
- (3) The commission may, on conditions it considers advisable, with the advance approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, exempt a person, class of persons, equipment or facilities from the application of all or any of the provisions of this Act or may limit or vary the application of this Act.
- (4) The commission has no power under this section to make an order respecting a person, or a person in respect of a matter, who has been exempted under section 22.

### **Withdrawal of application**

**88.1** If an applicant withdraws all or part of an application or the parties advise the commission that they have reached a settlement of all or part of an application, the commission may order that the application or part of it is dismissed.

### **Partial relief**

**89** On an application under this Act, the commission may make an order granting the whole or part of the relief applied for or may grant further or other relief, as the commission considers advisable.

### **Commencement of orders**

- 90** (1) In an order or regulation, the commission may direct that the order or regulation or part of it comes into operation
- (a) at a future time,
  - (b) on the happening of an event specified in the order or regulation, or
  - (c) on the performance, to the satisfaction of the commission, by a person named by it of a term imposed by the order.
- (2) The commission may, in the first instance, make an interim order, and reserve further direction for an adjourned hearing or further application.

### **Orders without notice**

- 91** (1) If the special circumstance of a case so requires, the commission may, without notice, make an interim order authorizing, requiring or forbidding anything to be done that the commission is empowered to authorize, require or forbid on application, notice or hearing.
- (2) The commission must not make an interim order under subsection (1) for a longer time than it considers necessary for a hearing and decision.
- (3) A person interested may, before final decision, apply to modify or set aside an interim order made without notice.

### **Directions**

- 92** If, in the exercise of a commission power under an Act, the commission directs that a structure, appliance, equipment or works be provided, constructed, reconstructed, removed, altered, installed, operated, used or maintained, the commission may, except as otherwise provided in the Act conferring the power, order
- (a) by what person interested at or within what time,
  - (b) at whose cost and expense,
  - (c) on what terms including payment of compensation, and
  - (d) under what supervision,
- the structure, appliance, equipment or works must be carried out.

### **Repealed**

**93-94** [Repealed 2004-45-170.]

### **Lien on land**

- 95** (1) If the commission makes an order for payment of money, costs or a penalty, the commission may register a copy of the order certified by the commission's secretary in a land title office.
- (2) On registration in a land title office, an order is a lien and charge on all the land of the person ordered to make the payment that is in the land title district in which the order is registered, to the same extent and with the same effect and realizable in the same way as a judgment of the Supreme Court under the [Court Order Enforcement Act](#).

### **Substitute to carry out orders**

- 96** (1) If a person defaults in doing anything directed by an order of the commission under this Act,
- (a) the commission may authorize a person it considers suitable to do the thing, and
  - (b) the person authorized may do the thing authorized and may recover from the person in default the expense incurred in doing the thing, as money paid for and at the request of that person.

- (2) The certificate of the commission of the amount expended is conclusive evidence of the amount of the expense.

### **Entry, seizure and management**

- 97** (1) The commission may take the steps and employ the persons it considers necessary to enforce an order made by it, and, for that purpose, may forcibly or otherwise enter on, seize and take possession of the whole or part of the business and the property of a public utility affected by the order, together with the records, offices and facilities of the utility.
- (2) The commission may, until the order has been enforced or until the Lieutenant Governor in Council otherwise orders, assume, take over and continue the management of the business and property of the utility in the interest of its shareholders, creditors and the public.
  - (3) While the commission continues to manage or direct the management of the utility, the commission may exercise, for the business and property, the powers, duties, rights and functions of the directors, officers or managers of the utility in all respects, including the employment and dismissal of officers or employees and the employment of others.
  - (4) On the commission taking possession of the business and property of the utility, each officer and employee of the utility must obey the lawful orders and instructions of the commission for that business and property, and of any person placed by the commission in authority in the management of the utility or a department of its undertaking or service.
  - (5) On taking possession of the business and property of a public utility, the commission may determine, receive or pay out all money due to or owing by the utility, and give cheques and receipts for money to the same extent and to the same effect as the utility or its officers or employees could do.
  - (6) The costs incurred by the commission under this section are in the discretion of the commission, and the commission may order by whom and in what amount or proportion costs are to be paid.

### **Defaulting utility may be dissolved**

- 98** (1) If a public utility incorporated under an Act of the Legislature fails to comply with a commission order, and the commission believes that no effective means exist to compel the utility to comply, the commission, in its discretion, may transmit to the Attorney General a certificate, signed by its chair and secretary, setting out the nature of the order and the default of the public utility.
- (2) Ten days after publication in the Gazette of a notice of receipt of the certificate by the Attorney General, the Lieutenant Governor in Council may, by order, dissolve the public utility.

## Part 7 — Decisions and Appeals

### Reconsideration

**99** (1) The commission, on application or on its own motion, may reconsider a decision, an order, a rule or a regulation of the commission and may confirm, vary or rescind the decision, order, rule or regulation.

(2) This section does not apply in relation to the following:

- (a) a rate that, [under section 21.1 \(5\)](#), is deemed to be set by order of the commission;
- (b) a regulation that, [under section 21.1 \(6\)](#), is deemed to be an order of the commission.

### Requirement for hearing

**100** If a hearing is held or required under this Act before a rule or regulation is made, the rule or regulation must not be altered, suspended or revoked without a hearing.

### Appeal to Supreme Court or Court of Appeal

**101** (1) An appeal lies from

- (a) a decision of the commission under section 109.1 or 109.2 to the Supreme Court, and
- (b) any other decision or order of the commission, [other than an order deemed under section 21.1 \(5\) or \(6\) to have been made by the commission](#), to the Court of Appeal, with leave of a justice of that court.

(2) The party appealing under subsection (1) (b) must give notice of the application for leave to appeal, stating the grounds of appeal, to the commission, to the Attorney General and to any party adverse in interest, at least 2 clear days before the hearing of the application.

(3) If leave is granted under subsection (1) (b), within 15 days from the granting, the appellant must give notice of appeal to the commission, to the Attorney General, and to any party adverse in interest.

(4) The commission and the Attorney General may be heard on an appeal under subsection (1) (b).

(4.1) The commission has full party status on an appeal under subsection (1) (a).

(5) [Repealed 2012-27-36.]

### Stay on appeal

**102** (1) An appeal to the Court of Appeal does not of itself stay or suspend the operation of the decision, order, rule or regulation appealed from, but the Court of Appeal may grant a suspension, in whole or in part, until the appeal is decided, on the terms the court considers advisable.

- (2) The commission may, in its discretion, suspend the operation of its decision, order, rule or regulation from which an appeal is taken under section 101 (1) (b) until the decision of the Court of Appeal is given.
- (3) An appeal to the Supreme Court under section 101 (1) (a) operates as a stay of the decision under section 109.2 to impose an administrative penalty, unless the court orders otherwise.

### **Costs of appeal**

**103** (1) [Repealed 2012-27-38.]

- (2) Neither the commission nor an officer, employee or agent of the commission is liable for costs in respect of an application or appeal referred to in section 101.

### **Case stated by commission**

- 104** (1) The commission may, on its own motion or on the application of a party who gives the security the commission directs, and must, on the request of the Attorney General, state a case in writing for the opinion of the Court of Appeal on a question that, in the opinion of the commission or of the Attorney General, is a question of law.
- (2) The Court of Appeal must hear and determine all questions of law arising on the stated case and must remit the matter to the commission with the court's opinion.
- (3) [Repealed 2012-27-39.]

### **Jurisdiction of commission exclusive**

- 105** (1) The commission has exclusive jurisdiction in all cases and for all matters in which jurisdiction is conferred on it by this or any other Act.
- (2) Unless otherwise provided in this Act, an order, decision or proceeding of the commission must not be questioned, reviewed or restrained by or on an application for judicial review or other process or proceeding in any court.

## **Part 8 — Offences and Penalties**

### **Offences**

- 106** (1) The following persons commit an offence:
  - (a) a person who fails or refuses to obey an order of the commission made under this Act;
  - (b) a person who does, causes or permits to be done an act, matter or thing contrary to this Act or omits to do an act, matter or thing required to be done by this Act;
  - (c) a public utility

- (i) that fails or refuses to prepare and provide to the commission in the time, manner and form, and with the particulars and verification required under this Act, an information return, the answer to a question submitted by the commission or information required by the commission under this Act,
  - (ii) that wilfully or negligently makes a return or provides information to the commission that is false in any particular,
  - (iii) that gives, or an officer of which gives, to an officer, agent, manager or employee of the utility a direction, instruction or request to do or refrain from doing an act referred to in paragraph (d) (i) to (vii) and in respect of which the officer, agent, manager or employee is convicted under paragraph (d) (i) to (vii), or
  - (iv) an officer, agent, manager or employee of which is convicted of an offence under paragraph (d) (viii);
- (d) an officer, agent, manager or employee of a public utility
- (i) who fails or refuses to complete and provide to the commission a report or form of return required under this Act,
  - (ii) who fails or refuses to answer a question contained in a report or form of return required under this Act,
  - (iii) who wilfully gives a false answer to a question contained in a report or form of return required under this Act,
  - (iv) who evades a question or gives an evasive answer to a question contained in a report or form of return required under this Act, if the person has the means to ascertain the facts,
  - (v) who, after proper demand under this Act, fails or refuses to exhibit to the commission or a person authorized by it an account, record or memorandum of the public utility that is in the person's possession or under the person's control,
  - (vi) who fails to properly use and keep the system of accounting of the public utility specified by the commission under this Act,
  - (vii) who refuses to do any act or thing in that system of accounting when directed by the commission or its representative,
  - (viii) on whom the commission serves notice directing the person to provide to the commission information or a return that the utility may be required to provide under this Act, and who wilfully refuses or fails to provide the information or return to the best of the person's knowledge, or means of knowledge, in the manner and time directed by the commission, or
  - (ix) who knowingly registers or causes to be registered on the books of the public utility any issue or transfer of shares that has been made contrary to section 54 (5), (7) or (8);

- (e) the president, and each vice president, director, managing director, superintendent and manager of a public utility that fails or refuses to obey an order of the commission made under this Act;
- (f) the mayor and each councillor or member of the ruling body of a municipality that fails or refuses to obey an order of the commission made under this Act;
- (g) [Repealed 2003-46-15.]
- (h) a person who obstructs or interferes with a commissioner, officer or person in the exercise of rights conferred or duties imposed under this Act;
- (i) a person who knowingly solicits, accepts or receives, directly or indirectly, a rebate, concession or discrimination for service of a public utility, if the service is provided or received in violation of this Act;
- (j) except so far as the person's public duty requires the person to report on or take official action, an officer or employee of the commission, or person having access to or knowledge of a return made to the commission or of information procured or evidence taken under this Act, other than a public inquiry or public hearing, who, without first obtaining the authority of the commission, publishes or makes known information, having obtained or knowing it to have been derived from the return, information or evidence;
- (k) a person who applies to a public utility to register on its books any issue or transfer of shares that has been made contrary to section 54 (5), (7) or (8).

(2) Subsection (1) (e) and (f) does not apply if the person proves

- (a) that, according to the person's position and authority, the person took all necessary and proper means in the person's power to obey and carry out, and to procure obedience to and the carrying out of the order, and
- (b) that the person was not at fault for the failure or refusal.

(3) Subsection (1) (h) does not apply if the commissioner, officer or person does not, on request at the time, produce a certificate of the commissioner's, officer's or person's appointment or authority.

(4) A person convicted of an offence under this section is liable to a penalty not greater than \$1 000 000.

(5) If this Act makes anything an offence, each day the offence continues constitutes a separate offence.

(6) Subject to section 109.2 (4), nothing in or done under this section affects the liability of a public utility otherwise existing or prejudices enforcement of an order of the commission in any way otherwise available.

- (7) If the commission imposes on a person an administrative penalty under section 109.2, a prosecution for an offence under this Act for the same contravention may not be brought against the person.

### **Restraining orders**

**107** If a person contravenes a term, condition or requirement of

- (a) a regulation under section 22,
- (b) a certificate of public convenience and necessity issued under section 46,
- (c) an approval under section 50 or 54 (5), (7) or (8),
- (d) an order under section 53 or 54 (10), or
- (e) a reliability standard adopted under section 125.2,

the contravention may be restrained in a proceeding brought by the minister in the Supreme Court.

### **Repealed**

**108** [Repealed 2012-27-42.]

### **Remedies not mutually exclusive**

**109** Subject to sections 106 (7) and 109.2 (4), if a person contravenes anything referred to in section 107, the remedies and penalties for the contravention are not mutually exclusive, and any or all of them may be applied in any one case.

## **Part 8.1 — Administrative Penalties**

### **Contraventions**

- 109.1** (1) After giving a person an opportunity to be heard, the commission, for the purposes of section 109.2, may find that the person has contravened a provision of
- (a) this Act or the regulations, or
  - (b) an order, standard or rule of the commission or a reliability standard adopted by the commission.
- (2) If a corporation contravenes a provision referred to in subsection (1), a director, officer or agent of the corporation who authorized, permitted or acquiesced in the contravention also contravenes the provision.
- (3) Without limiting section 112, if an employee, contractor or agent of a corporation contravenes a provision referred to in subsection (1) of this section in the course of carrying out the employment, contract or agency, the corporation also contravenes the provision.

- (4) The commission may not find that a person has contravened a provision referred to in subsection (1) if the person demonstrates to the satisfaction of the commission that
- (a) the person exercised due diligence to prevent the contravention, or
  - (b) the person's actions or omissions relevant to the provision were the result of an officially induced error.
- (5) Nothing in subsection (4) prevents the commission from doing anything else that the commission is authorized to do under this Act with respect to an act or omission by the person.
- (6) If a person referred to in subsection (2) or (3) has not contravened a provision referred to in subsection (1) as a result of demonstrating to the satisfaction of the commission anything referred to in subsection (4), the commission may find, subject to subsection (4), that any of the other persons referred to in subsection (2) or (3) have contravened the provision.
- (7) A person does not contravene a provision referred to in subsection (1) by doing or omitting to do something if that act or omission is reasonably necessary to conform to the requirements of the *Workers Compensation Act* or any regulations under that Act.

### **Administrative penalties**

- 109.2** (1) If the commission finds that a person has contravened a provision referred to in section 109.1 (1), the commission may impose an administrative penalty on the person in an amount that does not exceed the prescribed limit.
- (2) If a contravention of a prescribed provision occurs over more than one day or continues for more than one day, separate administrative penalties, each not exceeding the prescribed limit for the purposes of subsection (1), may be imposed for each day the contravention continues.
- (3) Before the commission imposes an administrative penalty on a person, the commission, in addition to considering anything else the commission considers relevant, must consider the following:
- (a) previous contraventions by, administrative penalties imposed on and orders issued to the following:
    - (i) the person;
    - (ii) if the person is an individual, a corporation for which the individual is or was a director, officer or agent;
    - (iii) if the person is a corporation, an individual who is or was a director, officer or agent of the corporation;
  - (b) the gravity and magnitude of the contravention;
  - (c) the extent of the harm to others resulting from the contravention;
  - (d) whether the contravention was repeated or continuous;

- (e) whether the contravention was deliberate;
  - (f) any economic benefit derived by the person from the contravention;
  - (g) the person's efforts to prevent and correct the contravention;
  - (h) the cost of compliance with the provision contravened;
  - (i) whether the person self-reported the contravention;
  - (j) the degree and quality of cooperation during the commission's investigation;
  - (k) any undue hardship that might arise from the amount of the penalty;
  - (l) any other matters prescribed by the Lieutenant Governor in Council.
- (4) If a person is charged with an offence under this Act, an administrative penalty may not be imposed on the person in respect of the same circumstances that gave rise to the charge.

### **Notice of contravention or penalty**

**109.3** (1) If the commission finds under section 109.1 that a person has contravened a provision referred to in that section or imposes under section 109.2 an administrative penalty on a person, the commission must give to the person a notice of the decision, and the notice must include reasons for the decision and specify the following:

- (a) the contravention;
  - (b) the amount of the penalty, if any;
  - (c) the date by which the penalty, if any, must be paid;
  - (d) the person's right, with respect to the decision, to apply for a reconsideration under section 99 or to appeal it under section 101;
  - (e) an address to which a request for a reconsideration under section 99 may be sent.
- (2) If the commission imposes an administrative penalty on a person, the commission may make public the reasons for and the amount of the penalty.

### **Due date of penalty**

**109.4** A person on whom an administrative penalty is imposed under section 109.2 must pay the penalty

- (a) within 30 days after the date on which the notice referred to in section 109.3 (1) is given to the person, or
- (b) by a later date ordered by the commission.

### **Recovery of penalty from ratepayers prohibited**

**109.5** In setting rates for a public utility, the commission must not allow the public utility to recover from persons who receive or may receive service from the public utility the

costs of paying an administrative penalty imposed under this Part.

### **Enforcement of administrative penalty**

- 109.6** (1) An administrative penalty constitutes a debt payable to the government by the person on whom the penalty is imposed.
- (2) If a person fails to pay an administrative penalty as required under section 109.4, the government may file with the Supreme Court or Provincial Court a certified copy of the notice imposing the penalty and, on being filed, the notice has the same force and effect, and all proceedings may be taken on the notice, as if the notice were a judgment of that court.

### **Revenue from administrative penalties**

- 109.7** The commission must pay into the consolidated revenue fund all amounts derived from administrative penalties.

### **Limitation period**

- 109.8** (1) The time limit for giving a notice under section 109.3 imposing an administrative penalty is 2 years after the date on which the act or omission alleged to constitute the contravention first came to the attention of the chair of the commission.
- (2) A certificate purporting to have been issued by the chair of the commission and certifying the date referred to in subsection (1) is proof of that date.

## **Part 9 — General**

### **Powers of commission in relation to other Acts**

- 110** The powers given to the commission by this Act apply
- (a) even though the subject matter about which the powers are exercisable is the subject matter of an agreement or another Act,
  - (b) in respect of service and rates, whether set by or the subject of an agreement or other Act, or otherwise, and
  - (c) if the service or rates are governed by an agreement, whether the agreement is incorporated in, or ratified, or made binding by a general or special Act, or otherwise.

### **Substantial compliance**

- 111** Substantial compliance with this Act is sufficient to give effect to the orders, rules, regulations and acts of the commission, and they must not be declared inoperative, illegal or void for want of form or an error or omission of a technical or clerical nature.

### **Vicarious liability**

**112** In construing and enforcing this Act, or a rule, regulation, order or direction of the commission, an act, omission or failure of an officer, agent or other person acting for or employed by a public utility, if within the scope of the person's employment, is deemed in every case to be the act, omission or failure of the utility.

### **Public utilities may apply**

**113** A person who is subject to regulation under this Act may make application or complaint to the commission about a matter affecting a public utility, as if made by another party interested.

### **Municipalities may apply**

**114** (1) In this section, "**municipality**" includes a regional district.

(2) If a municipality believes that the interests of the public in the municipality or a part of it are sufficiently concerned, the municipality may, by resolution, become an applicant, complainant or intervenant in a matter within the commission's jurisdiction.

(3) The municipality may, for subsection (2), take a proceeding or incur expense necessary

(a) to submit the matter to the commission,

(b) to oppose an application or complaint before the commission, or

(c) if necessary, to become a party to a proceeding or appeal under this Act.

### **Certified documents as evidence**

**115** (1) A copy of a rule, regulation, order or other document in the commission secretary's custody, purporting to be certified by the secretary to be a true copy, is evidence of the document without proof of the signature.

(2) A certificate purporting to be signed by the commission secretary stating that no rule, regulation or order on a specified matter has been made by the commission, is evidence of the fact stated without proof of the signature.

### **Class representation**

**116** (1) The commission may appoint counsel to represent a class of persons interested in a matter for the purpose of instituting or attending on an application or hearing before the commission or another tribunal or authority.

(2) The commission may fix the costs of the counsel and may order by whom and in what amount or proportion they be paid.

### **Costs of commission**

**117** (1) In this section, "**costs of the commission**" includes costs incurred by the commission for the services of consultants and experts engaged in connection with the proceeding.

- (2) The commission may order that the costs of the commission incidental to a proceeding before it are to be paid by one or more participants in the proceeding in such amounts and proportions as the commission may determine.

### **Participant costs**

- 118** (1) The commission may order a participant in a proceeding before the commission to pay all or part of the costs of another participant in the proceeding.
- (2) If the commission considers it to be in the public interest, the commission may pay all or part of the costs of participants in proceedings before the commission that were commenced on or after April 1, 1993 or that are commenced after June 18, 1993.
- (3) Amounts paid for costs under subsection (2) must not exceed the limits prescribed for the purposes of this section.

### **Tariff of fees**

- 119** With the advance approval of the Lieutenant Governor in Council, the commission may prescribe a tariff of fees for a matter within the commission's jurisdiction.

### **No waiver of rights**

- 120** (1) Nothing in this Act releases or waives a right of action by the commission or a person for a right, penalty or forfeiture that arises under a law of British Columbia.
- (2) No penalty enforceable under this Act is a bar to or affects recovery for a right, or affects or bars a proceeding against or prosecution of a public utility, its directors, officers, agents or employees.

### **Relationship with *Local Government Act***

- 121** (1) Nothing in or done under the *Community Charter* or the *Local Government Act*
  - (a) supersedes or impairs a power conferred on the commission or an authorization granted to a public utility, or
  - (b) relieves a person of an obligation imposed under this Act or the *Gas Utility Act*.
- (2) In this section, "**authorization**" means
  - (a) a certificate of public convenience and necessity issued under section 46,
  - (b) an exemption from the application of section 45 granted, with the advance approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, by the commission under section 88, and
  - (c) an exemption from section 45 granted under section 22, only if the public utility meets the conditions prescribed by the Lieutenant

Governor in Council.

- (3) For the purposes of subsection (2) (c), the Lieutenant Governor in Council may prescribe different conditions for different public utilities or categories of public utilities.

**Repealed**

122 [Repealed 2004-45-172.]

**Service of notice**

- 123 (1) A notice that the commission is empowered or required to give to a person under this Act must be in writing and may be served either personally or by mailing it to the person's address.
- (2) If a notice is mailed, service of the notice is deemed to be effected at the time at which the letter containing the notice, properly addressed, postage prepaid and mailed, would be delivered in the ordinary course of post.

**Reasons to be given**

- 124 (1) If an application to the commission is opposed, the commission must prepare written reasons for its decision.
- (2) If an application is unopposed, the commission may, and at the request of the applicant must, prepare written reasons for its decision.
- (3) Written reasons must be made available by the secretary to any person on payment of the fee set by the commission.
- (4) [Repealed 2003-46-20.]

**Regulations**

- 125 (1) The Lieutenant Governor in Council may make regulations as referred to in section 41 of the *Interpretation Act*.
- (2) Without limiting subsection (1), the Lieutenant Governor in Council may, for the purpose of recovering the expenses arising out of the administration of this Act in a fiscal year, make regulations as follows:
- (a) setting, or authorizing the commission to set, by order of the commission, and to collect fees, levies or other charges from
    - (i) public utilities, a class of public utility or a particular public utility, and
    - (ii) other persons to whom a provision of this Act applies or a class of those persons;
  - (b) setting, or authorizing the commission to set, the fees, levies or other charges payable by the members of the different classes referred to in paragraph (a) in different amounts;

- (c) exempting, or authorizing the commission to exempt, a public utility or other person, or a class of either of them, from the payment of a fee, levy or other charge;
  - (d) authorizing the commission to retain all or part of any fees, levies or other charges collected by the commission under a regulation;
  - (e) requiring the commission to set a rate for the purposes of section 28 (2.1) and prescribing requirements for the purposes of that section.
- (2.1) Without limiting subsection (1), the Lieutenant Governor in Council may make regulations respecting the imposition of administrative penalties, including, without limitation, prescribing
- (a) provisions for the purposes of section 109.2 (2),
  - (b) matters to be considered under section 109.2 (3) before imposing an administrative penalty,
  - (c) the criteria for determining appropriate administrative penalties, and
  - (d) different limits on different administrative penalties, including different limits for contraventions by different classes of persons.
- (3) The commission may make regulations on a matter for which it is empowered by this Act to make regulations.

### **Minister's regulations**

**125.1** (1) In this section, "**minister**" means the minister responsible for the administration of the *Hydro and Power Authority Act*.

(2) and (3) [Repealed 2010-22-72.]

(4) The minister may make regulations as follows:

- (a) [Repealed 2010-22-72.]
- (b) respecting exemptions under section 22;
- (c) and (d) [Repealed 2010-22-72.]
- (e) for the purposes of sections 44.1 and 44.2,
  - (i) prescribing rules for determining whether a demand-side measure, or a class of demand-side measures, is adequate, cost-effective or both,
  - (ii) declaring a demand-side measure, or a class of demand-side measures, to be cost effective and necessary for adequacy, and
  - (iii) prescribing rules or factors a public utility must use in making the estimate referred to in section 44.1 (2) (a);
  - (iv) [Repealed 2010-22-72.]
- (f) [Repealed 2010-22-72.]

- (g) prescribing factors and guidelines for the purposes of section 58 (2.1)
    - (b), including, without limitation, factors and guidelines to encourage
      - (i) energy conservation or efficiency,
      - (ii) the use of energy during periods of lower demand,
      - (iii) the development and use of energy from clean or renewable resources, or
      - (iv) the reduction of the energy demand a public utility must serve;
  - (h) defining a term or phrase used in section 58.1 and not defined in this Act;
    - (i) identifying facts that must be used in interpreting the definition in section 58.1;
  - (j) to (n) [Repealed 2010-22-72.]
  - (o) prescribing standard-making bodies for the purposes of section 125.2 (1) and requirements and matters for the purposes of section 125.2 (3).
  - (p) [Repealed 2015-42-26.]
- (5) In making a regulation under this section, the minister may
- (a) make regulations of specific or general application, and
  - (b) make different regulations for different persons, places, things, measures, transactions or activities.

### **Adoption of reliability standards, rules or codes**

**125.2** (1) In this section:

**"reliability standard"** means a reliability standard, rule or code established by a standard-making body for the purpose of being a mandatory reliability standard for planning and operating the North American bulk electric system, and includes any substantial change to any of those standards, rules or codes;

**"standard-making body"** means

- (a) the North American Electric Reliability Corporation,
  - (b) the Western Electricity Coordinating Council, and
  - (c) a prescribed standard-making body.
- (2) For greater certainty, the commission has exclusive jurisdiction to determine whether a reliability standard is in the public interest and should be adopted in British Columbia.
- (3) The authority must review each reliability standard and provide to the commission, in accordance with the regulations, a report assessing
- (a) any adverse impact of the reliability standard on the reliability of electricity transmission in British Columbia if the reliability standard were adopted under subsection (6),

- (b) the suitability of the reliability standard for British Columbia,
  - (c) the potential cost of the reliability standard if it were adopted under subsection (6),
  - (c.1) the application of the reliability standard to persons or persons in respect of specified equipment if the reliability standard were adopted under subsection (6), and
  - (d) any other matter prescribed by regulation or identified by order of the commission for the purposes of this section.
- (4) The commission may make an order for the purposes of subsection (3) (d).
- (5) If the commission receives a report under subsection (3), the commission must
  - (a) make the report available to the public in a reasonable manner, which may include by electronic means, and for a reasonable period of time, and
  - (b) consider any comments the commission receives in reply to the publication referred to in paragraph (a).
- (6) After complying with subsection (5), the commission, subject to subsection (7), must, by order, adopt the reliability standards addressed in the report if the commission considers that the reliability standards are required to maintain or achieve consistency in British Columbia with other jurisdictions that have adopted the reliability standards.
- (7) The commission is not required to adopt a reliability standard under subsection (6) if the commission determines, after a hearing, that the reliability standard is not in the public interest.
- (8) Subject to subsection (8.3), a reliability standard adopted under subsection (6) applies as specified in an order made under subsection (6).
- (8.1) At the request of the commission, the authority must provide to the commission, in accordance with any directions made by the commission, a report assessing the application of a reliability standard adopted under subsection (6) to a specified person, a class of persons or a person in respect of specified equipment.
- (8.2) Subsection (5) applies to a report received by the commission under subsection (8.1).
- (8.3) After complying with subsection (5) respecting a report received under subsection (8.1), the commission may, by order, specify that a reliability standard adopted under subsection (6) applies or does not apply to a specified person, a class of persons or a person in respect of specified equipment.
- (9) A reliability standard adopted under subsection (6) applies as specified in an order made under subsection (6) or (8.3) despite an exemption issued under section 22 or 88 (3).

(10) The commission may make orders providing for the administration of adopted reliability standards.

(10.1) Without limiting subsection (10), section 43 (1) (a) and (b) (i) applies to a person to whom a reliability standard adopted under subsection (6) of this section applies, as though the person were a public utility.

(11) The commission, on its own motion or on complaint, may

(a) rescind an adoption made under subsection (6), or

(b) adopt a reliability standard previously rejected under subsection (7)

if the commission determines, after a hearing, that the rescission or adoption is in the public interest.

(12) The commission, without the approval of the minister responsible for the administration of the *Hydro and Power Authority Act*, may not set a standard or rule under section 26 of this Act with respect to a matter addressed by a reliability standard assessed in a report submitted to the commission under subsection (3) of this section.

### **Intent of Legislature**

**126** If a provision of this Act is held to be beyond the powers of British Columbia, that provision must be severed from the remainder of the Act, and the remaining provisions of the Act have the same effect as if they had been originally enacted as a separate enactment and as the only provisions of this Act.

Federal Court



Cour fédérale

**Date: 20110929**

**Docket: T-514-11**

**Citation: 2011 FC 1120**

**Ottawa, Ontario, September 29, 2011**

**PRESENT: The Honourable Mr. Justice Russell**

**BETWEEN:**

**BELL CANADA**

**Applicant**

**and**

**ATTORNEY GENERAL OF CANADA,  
MINISTER OF INDUSTRY AND ROGERS  
COMMUNICATIONS INC.**

**Respondents**

**REASONS FOR JUDGMENT AND JUDGMENT**

[1] This is an application under the *Federal Courts Act*, RSC 1985, c. F-7 for judicial review to:

(a) quash and set aside the publication in the *Canada Gazette* on 19 March 2011 as Gazette Notice No. DGTP-002-11 (Notice) by the Minister of Industry (Minister) of the 26 January 2011 petition (Petition) by Rogers Communications Inc. (Rogers) pursuant to subsections 12(1) and 12(4) of the

*Telecommunications Act*, S.C. 1993, c. 38 (Act); and (b) prohibit the Governor in Council (Cabinet) from considering the Petition.

## **BACKGROUND**

[2] In 2002, the Canadian Radio-television and Telecommunications Commission (CRTC) issued Decision 2002-34, which permitted Incumbent Local Exchange Carriers (ILECs), including Bell Canada (Bell), to charge more than a permitted maximum tariff. Though these ILECs were permitted to charge above the tariff, the excess amount was to be tracked in a separate account (Deferral Account) and segregated from other funds. The CRTC retained the authority to determine the use of these funds at a later date.

[3] On 14 December 2006, by Order in Council P.C. 2006-1534 SOR/2006-355, the Cabinet gave the *Order Issuing a Direction to the CRTC on Implementing the Canadian Telecommunication Policy Objectives* (Policy Direction) under section 8 of the Act. Among other things, the Policy Direction directed the CRTC to “rely on market forces to the maximum extent feasible as the means of achieving the telecommunications policy objectives, and when relying on regulation, use measures that [...] interfere with the operation of competitive market forces to the minimum extent necessary to meet the policy objectives.”

[4] Beginning in 2006, the CRTC issued a series of decisions which established principles for the distribution of the Deferral Account monies. The CRTC decided in Decision 2006-9 that the Deferral Account funds would be used for two purposes: (1) improving access for people with disabilities; and (2) extending broadband internet services into rural and remote locations. Any excess funds would be returned to customers as rebates. Several parties appealed that decision to the

Federal Court of Appeal: Bell appealed the portion of the decision requiring it to return a portion of the funds as rebates to customers, while other parties appealed the requirement that the funds be used for broadband expansion. Ultimately, the Supreme Court of Canada, in *Bell Canada v Bell Aliant Regional Communications* 2009 SCC 40, held that the CRTC's allocation of funds for broadband expansion, increasing access for people with disabilities, and rebates to customers was valid, as the allocation of Deferral Account funds is within the CRTC's rate-setting authority.

[5] In Decisions 2006-9 and 2007-15 the CRTC had rejected the proposal that the Deferral Account funds should be available to all telecommunications companies and awarded on the basis of a competitive bidding process. This competitive bidding process, Rogers had submitted, would fulfill the principle of competitive neutrality which the Telecommunications Policy Review Panel had recommended the CRTC adopt in its 2006 Final Report. Rather than use a competitive bidding process which it felt would “add a significant layer of complexity, delay the implementation of broadband expansion, and result in substantial administrative and regulatory burden,” the CRTC opted for the use of a proposal system. In the proposal system, the CRTC would examine proposals submitted by the ILECs for the use of the Deferral Account funds and approve or disapprove of them based on their compliance with the conditions established in Decision 2006-9. In Decision 2007-15, the CRTC approved the use of Deferral Account funds for Broadband expansion into 112 communities in Ontario. In Decision 2008-1, the CRTC approved several proposals to expand accessibility to telecommunications with Deferral Account funds and also set additional principles for how additional communities would be selected for expansion, the implementation of least-cost technology, and the recovery of uneconomic costs.

[6] In 2009, Bell filed a proposal with the CRTC to use \$303.6 million in Deferral Account funds to expand broadband access to 112 communities in Ontario. Bell proposed expanding broadband coverage using wireless high-speed packet access (HSPA+) technology. Among others, Rogers opposed this proposal, in part because Rogers had already implemented HSPA broadband technology in a number of these communities. Rogers argued that, for the CRTC to permit Bell to expand its network using HSPA+ technology would not in fact expand broadband access, and so was contrary to the principles established by the CRTC in Decisions 2006-9, 2007-15 and 2008-1 (the Deferral Account Decisions).

[7] In CRTC Decision 2010-637, the Commission rejected Bell's proposal. In that decision, the CRTC approved the use of \$306.3 million of Deferral Account funds for expanding broadband internet services to 112 communities. However, rather than using the wireless HSPA+ technology, the CRTC required Bell to complete the expansion using wireline Digital Subscriber Line (DSL) technology. The remaining balance in the Deferral Account fund of \$277 million would be returned to consumers as a rebate. Bell proposed to roll out this technology over a four-year period, beginning with 15 communities in 2011 and completing the expansion by 2015.

[8] In 2010, given advances in technology, Bell filed an application with the CRTC to vary Decision 2010-637, and to allow Bell to complete the expansion into the approved communities using improved wireless technology (HSPA+). Rogers opposed this application to vary, saying Bell's proposal did not comply with the Guidelines established in the Deferral Account Decisions and violated the Policy Direction. The CRTC in Decision 2010-805 approved Bell's proposal to complete the expansion using wireless HSPA+ technology and noted that

it had rejected this idea in both Telecom Decisions 2006-9 and 2007-50 (*sic*), since it would add a significant layer of complexity, delay

the implementation of broadband expansion, and result in substantial administrative and regulatory burden. The Commission considers that these reasons continue to be valid.

[9] In response, on 26 January 2011, Rogers filed the Petition with the Clerk of the Privy Council under subsection 12(1) of the Act. In the Petition, Rogers asks the Cabinet to vary Decision 2010-805 to reduce the amount of deferral account funds approved to only the amount necessary to cover the uneconomic portion of Bell's expansion into the first 15 communities in its proposal. Rogers also asks the Cabinet to vary Decision 2010-805 to permit a competitive bidding process for expansion into the remaining 97 approved communities.

[10] Having received the Petition from Rogers, the Minister published the Notice in the 19 March 2011 issue of the *Canada Gazette*. The Notice informs the public that the Minister has received the Petition, that the Petition and the supporting documents can be obtained electronically on Industry Canada's Spectrum Management and Telecommunications website, and that submissions regarding the Petition must be made within thirty days of the publication of the Notice in the *Gazette*. The publication of this Notice is what Bell seeks to quash in this application for judicial review. Bell also seeks to prohibit Cabinet from considering the Petition.

## **DECISION UNDER REVIEW**

[11] Bell seeks judicial review to quash the Notice published by the Minister in the *Canada Gazette*. The Notice provides in relevant part as follows:

Notice is hereby given that a petition from Rogers Communications Partnership (hereinafter referred to as Rogers), has been received by the Governor in Council (GIC) under section 12 of the *Telecommunications Act* with respect to a decision issued by the Canadian Radio-television and Telecommunications Commission (CRTC), concerning the use of wireless technology and deferral

account funds for extending broadband service to approved communities.

Subsection 12(1) of the *Telecommunications Act* provides that, within one year after a decision by the CRTC, the GIC may, on petition in writing presented to the GIC within 90 days after the decision, or on the GIC's own motion, by order, vary or rescind the decision or refer it back to the CRTC for reconsideration of all or a portion of it.

In its petition, dated January 26, 2011, Rogers requests that the GIC vary Telecom Decision CRTC 2010-805, *Bell Canada – Applications to review and vary certain determinations in Telecom Decision 2010-637 concerning the use of high-speed packet access wireless technology and the deferral account balance*. The reasons for this request are included in Rogers' petition.

Submissions regarding this petition should be filed within 30 days of the publication of this notice in the *Canada Gazette*. All comments received will be posed on Industry Canada's Spectrum Management and Telecommunications Web site at [www.ic.gc.ca/spectrum](http://www.ic.gc.ca/spectrum).

[12] Bell also seeks an order of prohibition preventing the Cabinet from considering and determining Rogers's Petition.

## ISSUES

[13] Bell raises two basic issues in this application:

1. Whether the Minister had jurisdiction to publish the Notice in the *Canada Gazette*;
2. Whether the Cabinet has jurisdiction to hear Rogers's Petition.

## STATUTORY PROVISIONS

[14] The following statutory provisions of the Act are relevant to these proceedings:

2. (1) In this Act,

“decision” includes a determination made by the Commission in any form;

...

**CANADIAN  
TELECOMMUNICATIONS  
POLICY**

7. It is hereby affirmed that telecommunications performs an essential role in the maintenance of Canada’s identity and sovereignty and that the Canadian telecommunications policy has as its objectives:

...

(c) to enhance the efficiency and competitiveness, at the national and international levels, of Canadian telecommunications

...

(f) to foster increased reliance on market forces for the provision of telecommunications services and to ensure that regulation, where required, is efficient and effective;

...

**Variation, rescission or referral**

2. (1) Les définitions qui suivent s’appliquent à la présente loi.

« décision » Toute mesure prise par le Conseil, quelle qu’en soit la forme.

...

**POLITIQUE  
CANADIENNE DE  
TÉLÉCOMMUNICATION**

7. La présente loi affirme le caractère essentiel des télécommunications pour l’identité et la souveraineté canadiennes; la politique canadienne de télécommunication vise à

...

c) accroître l’efficacité et la compétitivité, sur les plans national et international, des télécommunications canadiennes;

...

f) favoriser le libre jeu du marché en ce qui concerne la fourniture de services de télécommunication et assurer l’efficacité de la réglementation, dans le cas où celle-ci est nécessaire;

...

**Modification, annulation ou réexamen**

**12.** (1) Within one year after a decision by the Commission, the Cabinet may, on Petition in writing presented to the Cabinet within ninety days after the decision, or on the Cabinet's own motion, by order, vary or rescind the decision or refer it back to the Commission for reconsideration of all or a portion of it.

...

(4) On receipt of a Petition, the Minister shall publish in the *Canada Gazette* a notice of its receipt indicating where the Petition and any Petition or submission made in response to it may be inspected and copies of them obtained.

...

### **Partial or additional relief**

**60.** The Commission may grant the whole or any portion of the relief applied for in any case, and may grant any other relief in addition to or in substitution for the relief applied for as if the application had been for that other relief.

...

### **Review of decisions**

**12.** (1) Dans l'année qui suit la prise d'une décision par le Conseil, le gouverneur en conseil peut, par décret, soit de sa propre initiative, soit sur demande écrite présentée dans les quatre-vingt-dix jours de cette prise, modifier ou annuler la décision ou la renvoyer au Conseil pour réexamen de tout ou partie de celle-ci et nouvelle audience.

...

(4) Dès réception de la demande, le ministre publie un avis dans la *Gazette du Canada* faisant état de la réception et indiquant où la demande, ou toute autre demande ou observation présentées en réponse à celle-ci peuvent être consultées et où il peut en être obtenu copie.

...

### **Réparation**

**60.** Le Conseil peut soit faire droit à une demande de réparation, en tout ou en partie, soit accorder, en plus ou à la place de celle qui est demandée, la réparation qui lui semble justifiée, l'effet étant alors le même que si celle-ci avait fait l'objet de la demande.

...

### **Révision et annulation**

**62.** The Commission may, on application or on its own motion, review and rescind or vary any decision made by it or re-hear a matter before rendering a decision.

**62.** Le Conseil peut, sur demande ou de sa propre initiative, réviser, annuler ou modifier ses décisions, ou entendre à nouveau une demande avant d'en décider.

## STANDARD OF REVIEW

[15] The Supreme Court of Canada in *Dunsmuir v New Brunswick*, 2008 SCC 9, held that a standard of review analysis need not be conducted in every instance. Instead, where the standard of review applicable to a particular question before the court is well-settled by past jurisprudence, the reviewing court may adopt that standard of review. Only where this search proves fruitless must the reviewing court undertake a consideration of the four factors comprising the standard of review analysis.

[16] Both of the issues raised involve true questions of *vires*. As the Supreme Court of Canada held in *Dunsmuir*, true questions of *vires* attract review on the standard of Correctness. Also in *Dunsmuir*, at paragraph 50, the Supreme Court of Canada held that

When applying the correctness standard, a reviewing court will not show deference to the decision maker's reasoning process; it will rather undertake its own analysis of the question. The analysis will bring the court to decide whether it agrees with the determination of the decision maker; if not, the court will substitute its own view and provide the correct answer. From the outset, the court must ask whether the tribunal's decision was correct.

## ARGUMENTS

### The Applicant

[17] Bell argues that the Cabinet should be prohibited from hearing the Petition because the Cabinet lacks jurisdiction as the Petition does not relate to the subject matter of Decision 2010-805, the decision it purports to vary, and so is outside subsection 12(1) of the Act. Bell also argues that because the true subject matter of the Petition is the variance of Decisions 2006-9 and 2007-15, the Petition is out of time and so beyond the jurisdiction of the Cabinet to hear.

[18] With respect to the Notice, Bell argues that it should be quashed by the Court as it relates to a proceeding over which the Cabinet does not have jurisdiction. Since Parliament intended the Minister to act in accordance with the Cabinet's jurisdiction, Parliament could not have intended subsection 12(4) of the Act to require the Minister to publish notices over which the Cabinet had no jurisdiction.

### **The Cabinet Should be Prohibited From Hearing The Petition Because it Lacks Jurisdiction**

[19] Bell says that when the Cabinet is exercising an authority delegated to it by statute, it must do so within the bounds of the powers granted to it. Any exercise of the power is reviewable by the Court and, where the Cabinet purports to exercise its power outside of the bounds established for that power, the Court can intervene to quash or, where necessary, prohibit the exercise of that power.

[20] Bell also argues that, as with the exercise of a delegated power by any body, the Cabinet only has jurisdiction to act where the necessary conditions precedent have been fulfilled. Where the Cabinet does not meet the statutory conditions precedent, any exercise of that power is *ultra vires*. In this case, if the exercise of the subsection 12(1) power to review Decision 2010-805 requires the Cabinet to ignore a mandatory condition precedent, the Court ought to intervene. In support of the use of prohibition to prevent the unlawful exercise of delegated power, Bell refers to the Federal Court of Appeal decision in *Canadian Red Cross Society v Canada (Commission of Inquiry on the Blood System in Canada – Krever Commission)*, [1997] 2 FC 36, [1997] FCJ No 17 (CA) at paragraph 28:

In the instant case, if the Commissioner did not have jurisdiction to make the findings in his report that he set out in the notices, then this is a case in which want of jurisdiction is apparent, or at least one in which the Commissioner “is undoubtedly about to step outside his jurisdiction”. It would be intolerable to compel the appellants to wait until the report was made before allowing them to object to it: the harm would then be greater, and probably irreparable.

Since, by hearing the Petition, the Cabinet will step outside its jurisdiction, Bell argues that prohibition is an appropriate remedy in this case.

### **The Cabinet Lacks Jurisdiction Because it Has Not Fulfilled the Mandatory Conditions Precedent**

[21] Bell also argues that there are two mandatory (though not statutory) conditions precedent for the exercise of the review power under subsection 12(1): (1) the existence of a decision by the CRTC on the same subject matter as the Petition; and (2) variance of the CRTC decision within one year of its making. Since neither of these conditions has been fulfilled in this case, hearing the Petition under subsection 12(1) is outside the jurisdiction of the Cabinet and should be prohibited.

### Existence of a Decision on the Same Subject Matter

[22] Bell relies on *British Columbia (Attorney General) v Canada (Attorney General)*, [1994] SCJ No 35; [1994] 2 SCR 41 for the proposition that a petition to the Cabinet under subsection 12(1) must concern the same subject matter as the decision which is sought to be varied. As the Supreme Court of Canada said in that case at paragraph 139,

While the Cabinet can vary an order “at any time” pursuant to s. 64 of the *National Transportation Act, 1987*, and while the s. 64 jurisdiction has been recognized as vast in *Inuit Tapirisat*[,] the s. 64 power can only be exercised if a CTC or NTA “order” exists.

[23] Bell also relies on the following from *Jasper Park Chamber of Commerce v Canada (Attorney General)*, [1983] 2 FC 98; [1982] FCJ No 193, at paragraph 9:

I agree with counsel for the appellants that the Governor in Council under the authority given to it by subsection 64(1) is not entitled, under the guise of “variation” to do something of an entirely different nature. I agree that the Cabinet is constrained under subsection 64(1), when varying a Commission order, to deal with the same type or kind of order as the Commission was dealing with. I do not agree that subsection 64(1) authorizes the Governor in Council to vary any and all Commission orders no matter when they are issued or regardless of their subject-matter. In my view, Order R-22346 is not a relevant Order for the purposes of the discontinuance Order contained in section 2 of Schedule XV because as detailed supra, the passenger-train service which was the subject-matter of Order R-22346 was not the same passenger-train service as that ordered to be discontinued in section 2 of Schedule XV.

[24] Taken together, Bell says that these cases demonstrate that in order for the Cabinet to review a decision under subsection 12(1), the Petition must concern the same subject matter as the decision to be varied.

[25] In this case, Bell argues that the subject matter of the Petition is sufficiently different from that of the decision in question to remove it from the Cabinet's jurisdiction. Bell argues that Decision 2010-805 was solely about what kind of technology should be used in the implementation of the broadband expansion. Since the issue of competitive bidding, which Rogers seeks to have included by its Petition was not before the CRTC in its deliberations for Decision 2010-805, the subject matter of the Petition and the decision it purports to vary are different. Bell notes that competitive bidding had been considered and rejected by the CRTC in Decisions 2006-9 and 2007-15 and, as such, was not before the CRTC in the hearings related to Decision 2010-805.

### **Improperly Raised at Hearings**

[26] Bell also argues that competitive bidding was improperly raised by Rogers at the hearings related to Decision 2010-805. As a mere intervener in the hearings on Bell's application to vary Decision 2010-637, which resulted in Decision 2010-805, Rogers could not raise new issues for the CRTC to consider that were not in Bell's original application. Bell relies on the Supreme Court of Canada's statement in *Reference re: Goods and Services Tax*, [1992] 2 SCR 445; [1992] SCJ No 62 at paragraph 76:

Intervener status is granted when this Court feels that the intervener may be of assistance to the Court in resolving the principal issues before us. Intervener status is not granted to allow the intervener to raise an entirely new set of issues which are not addressed by other principal parties.

Bell says this means that an intervener in an administrative proceeding cannot raise new issues before the decision-maker.

[27] Bell also asserts that there is nothing in Decision 2010-805 to suggest that the CRTC intended to deal with competitive bidding. Bell points to paragraph 23 of that decision, which reads

With respect to the proposals to allow for competitive bidding in order to ensure the use of least-cost technology, the Commission notes that it rejected this idea both in Telecom Decisions 2006-9 and 2007-50 (*sic*), since it would add a significant layer of complexity, delay the implementation of broadband expansion, and result in substantial administrative and regulatory burden. The Commission considers that these reasons continue to be valid.

Bell says this statement is merely a reiteration of an earlier decision and is akin to a courtesy letter advising a party of a decision previously taken. This demonstrates that the issue of competitive bidding was not before the CRTC in Decision 2010-805. Since the issue of competitive bidding was not before the CRTC in Decision 2010-805, then the Petition which purports to vary that decision to include competitive bidding does not concern the same subject matter. As they do not concern the same subject matter, the Petition does not fulfil a mandatory condition precedent for the exercise of Cabinet's power under subsection 12(1).

### **Variance of the Decision Within Year**

[28] Bell further argues that the Petition is in substance about Decisions 2006-9 and 2007-15 because the subject matter of the Petition is competitive bidding which was also the subject matter of those decisions. This means that the Petition should be subject to the same limitation periods as those decisions. The limitation period for a petition to the Cabinet to vary Decision 2007-15 expired 12 June 2007, and for Decision 2006-9, it expired on 17 May 2006, so the Petition in the current case is well out of time. The expiry of a limitation period results in a loss of jurisdiction.

[29] Bell also argues that there is no discretion for Cabinet to extend the limitation period. This is shown by the legislative history of subsection 12(1). Where the predecessor section, subsection 64(1) of the *National Transportation Act*, RSC 1985, c. N-20, allowed Cabinet to vary a decision of the CRTC at any time, the current subsection 12(1) limits the application period to ninety days from the decision date, with an ultimate limitation period of one year. As there is a presumption that Parliament intends legislative changes to be meaningful, the change from an unlimited time to vary to a one year period to vary must have been intended to limit Cabinet's jurisdiction to vary CRTC decisions.

[30] Bell also argues that *Ontario Hydro v Cuddy International Corp.*, [1990] OJ No 676, establishes the principle that, where a later decision of a board clarifies an earlier decision with the same subject matter, while not being an entirely new decision, the limitation period for appeal runs from the date of the earlier decision. Since the true focus of the Petition is Decisions 2006-9 and 2007-15, the limitation period must run from the earlier dates.

[31] Because the Petition to vary the CRTC decision is out of time, the Cabinet lacks jurisdiction to consider it and must be prohibited from doing so by the Court.

### **The *Gazette* Notice Should be Quashed**

[32] In addition to prohibiting the Cabinet from hearing and deciding the Petition, Bell also argues that the Court should quash the Notice published in the *Canada Gazette*. Since the Cabinet does not have the jurisdiction to hear the Petition, the Notice should be quashed. Bell notes that courts have regularly and properly quashed notices of hearings which are held to be *ultra vires* the

entity making the decision. Further, though subsection 12(4) of the Act, under which the Minister published the Notice in the *Gazette*, is mandatory, Bell argues that Parliament intended the Minister to act in accord with the Cabinet's jurisdiction as the Minister is part of the Cabinet. It cannot be, Bell argues, that Parliament intended the Minister to publish notices for hearings that are *ultra vires* the Cabinet. As such, the Notice should be quashed.

### **The Respondent – Rogers**

[33] Rogers says that the Court should reject Bell's argument that the Petition is really seeking a Cabinet review of subject matter that was dealt with in Decisions 2006-9 and 2007-15. Relying on subsection 12(1) of the Act, Rogers argues that the only statutory conditions precedent for the Cabinet to have jurisdiction are that there be a decision by the CRTC and that relief be sought within the ninety-day limitation period established by the statute.

[34] Rogers asserts that its Petition seeks to vary Decision 2010-805 as it relates to the determination of the availability of wireless broadband, the effect of HSPA+ technology on competition, the impact of competitive bidding in the use of deferral account funds, and the CRTC's refusal to institute a competitive bidding process for the allocation of those funds. All of these issues, Rogers argues, were raised by the interested parties in the hearings leading up to Decision 2010-805 and the CRTC made determinations on each of them. As such, the Petition to vary is proper and within the jurisdiction of the Cabinet.

[35] Rogers argues that simply because parties other than Bell raised the issue of competitive bidding at the hearings, does not mean that this was not part of the subject matter of Decision 2010-

805. Further, although the CRTC considered and rejected the implementation of a competitive bidding arrangement in Decisions 2006-9 and 2007-15, those decisions do not prevent the consideration of competitive bidding in Decision 2010-805. The fact that the CRTC could have instituted competitive bidding in Decision 2010-805, but did not is within the Cabinet's jurisdiction to review. Rogers further argues that the CRTC is not bound by its own precedents and cannot fetter its discretion to decide each matter before it based on a full assessment of the facts and the law in each case. Though the CRTC decided not to implement a competitive bidding process in Decisions 2006-9 and 2007-15, this does not mean that the CRTC could not have implemented competitive bidding in Decision 2010-805.

[36] Rogers also notes that Bell characterised its own application in Decision 2010-805 as a new application or, in the alternative, an application to review and vary Decision 2010-637. Further, in the hearings, several companies, including Rogers, opposed the Decision 2010-805 application on several grounds, including that Bell's proposal was inconsistent with the 2006 Policy Direction made by Cabinet. As the question before the CRTC in Decision 2010-805 was whether Bell's application met the guidelines set for the allocation of the Deferral Account funds in accordance with telecommunications policy objectives, it is within the Cabinet's jurisdiction to hear and determine a Petition on those grounds. This is what Rogers's Petition is truly about and the Cabinet has the jurisdiction to hear and determine the matter.

### **The CRTC Did Not Fully Consider Competitive Bidding**

[37] Rogers takes issue with Bell's argument that the CRTC fully considered competitive bidding in Decisions 2006-9 and 2007-15. Rogers quotes from Macauley and Sprague's *Practice and Procedure Before Administrative Tribunals*:

...the notion of *stare decisis* is not applicable in the administrative sphere. Agencies are not only at liberty not to treat their earlier decisions as precedent, they are positively obligated not to do so.

Rogers argues that, although the CRTC had considered and rejected a competitive bidding process in earlier contexts and decisions, it was not bound to follow those decisions in Decision 2010-805. The CRTC was empowered to, and did, consider whether competitive bidding should be implemented in Decision 2010-805.

[38] Rogers notes that, following *Hopedale Developments v Oakville (Town)* (1965), 47 DLR (2d) 482 (ONCA), it is permissible for administrative tribunals to consider the principles established in their previous decisions in subsequent matters that come before them. They must, however, give each new matter full consideration. Thus, although the CRTC had previously considered and rejected competitive bidding, it was not foreclosed from considering this in Decision 2010-805.

[39] Rogers further argues that administrative tribunals such as the CRTC must have the flexibility to consider each decision in light of new developments. In Decision 2010-637, the CRTC did not have all the facts before it that were relevant to the determination of whether HSPA+ wireless technology would satisfy the established criteria, including its affect on competition. Even had the CRTC intended to determine for all time in Decision 2010-637 that competitive bidding would not be employed, it could not have done so as it could not possibly have had all the facts before it necessary to make such a determination.

### **Competitive Bidding Was Properly Before the CRTC**

[40] Although Bell has argued that it is not proper for interveners to raise new issues in proceedings, Rogers says that the jurisprudence cited by Bell in support of this proposition is not applicable to administrative proceedings. Rogers further argues that, even if it were applicable, it and the other telecommunications companies were interested parties in the proceedings related to Decision 2010-805 and could properly raise issues for the CRTC to consider.

[41] Rogers asserts that there is nothing in the CRTC rules, past or present, that would prevent Rogers or any other intervener from raising issues to be considered by the CRTC. Contrary to Bell's argument that Rules 13 and 27 of the former CRTC Telecommunications Rules of Practice would require an amendment to the pleadings to raise a new issue, Rogers argues that these Rules simply give the CRTC the discretion to require an amendment to the pleadings where it is necessary for an issue to be fully determined. Since these Rules are discretionary, it cannot be said that the CRTC did not intend to consider competitive bidding simply because it did not require pleadings to be amended. Further, the parties other than Bell raised the issues of competitive neutrality and competitive bidding in their submissions.

[42] Rogers also notes that, under section 60 of the Act, the powers of the CRTC to vary an order are broad. Because the CRTC could have ordered competitive bidding as a variance to Decision 2010-637, yet did not do so, this is a decision that is properly reviewable on petition to the Cabinet.

### **The CRTC Intended to Render a New Decision on Competitive Bidding**

[43] Rogers argues that the phrase in paragraph 23 of Decision 2010-805 that "these reasons continue to be valid" constitutes a fresh determination on the issue of competitive bidding which is reviewable by the Cabinet. Rogers relies on the decision of Justice Simon Noël in *Dumbrava v*

*Canada (Minister of Citizenship and Immigration)* [1995] FCJ No 1238; (1995) 101 FTR 230, in which he wrote at paragraph 15 that

Whenever a decision-maker who is empowered to do so agrees to reconsider a decision on the basis of new facts, a fresh decision will result whether or not the original decision is changed, varied or maintained. What is relevant is that there be a fresh exercise of discretion, and such will always be the case when a decision-maker agrees to reconsider his or her decision by reference to facts and submissions which were not on the record when the original decision was reached.

Since in this case the CRTC was considering whether to vary Decision 2010-637 based on the availability of the new HSPA+ technology and its impact on competition, Decision 2010-805 was a fresh exercise of discretion which is reviewable by the Cabinet.

[44] Rogers also argues that the words “reasons” and “continue” in paragraph 23 of Decision 2010-805 demonstrate that this is a fresh exercise of discretion. “Continue” refers to the fact that the CRTC is making a new decision in the present. “Reasons” shows that the CRTC is not simply restating its earlier decisions, but is adopting the rationale of previous decision in its current Decision 2010-805.

#### **The Respondents – The Minister and the Attorney General of Canada (AGC)**

[45] The Minister and the AGC (Canada) have made joint submissions which support and complement those of Rogers. In brief, Canada says first that the publication of a notice of petition under subsection 12(4) of the Act is mandatory and does not impact rights or deal with substantive issues. Second, the proper course is for the court to decline to exercise its prerogative to prohibit the Cabinet from considering the Petition because the Cabinet has authority to determine questions of

jurisdiction and it would be premature for the Court to intervene at this stage. Also, because prohibition is an exceptional remedy which should only be exercised where a want of jurisdiction is apparent, and since it is not apparent in this case, prohibition should not be granted.

[46] Canada says that there are three routes of review available from decisions of the CRTC: (i) the CRTC has the authority, within the scheme of the Act, to reconsider any of its decisions, either by application of a party or on its own motion; (ii) a decision of the CRTC may also be appealed directly to the Federal Court of Appeal; or (iii) a Petition may be filed asking the Cabinet to vary, rescind, or remit for re-determination the decision. Further, the Minister may, on consultation with the Provinces, make a recommendation to the CRTC on how it ought to exercise its discretion.

### **Publication of a *Gazette* Notice is Mandatory**

[47] Based on the plain language of subsection 12(4), the Minister has no discretion whether or not to publish a notice of petition once the statutory conditions have been met. Since the decision to publish is mandatory and involves no exercise of discretion, *certiorari* is not available to quash this decision.

[48] Canada notes that *certiorari* is available to quash decisions where a public decision-maker has acted in excess of its authority. In *Martineau v Matsqui Institution* [1980] 1 SCR 602 at page 628, Justice Dickson wrote that

*Certiorari* is available as a general remedy for supervision of the machinery of government decision-making. The order may go to any public body with power to decide any matter affecting the rights, interests, property, privileges, or liberty of any person. The basis for

the broad reach of this remedy is the general duty of fairness resting on all public decision-makers.

Since, in this case, the decision to publish the notice has no effect on the rights of Bell or any other person, *certiorari* is not available to quash the Notice. The publishing of the Notice does not bind the Minister or the Cabinet to make a recommendation or to consider and decide the Petition; the only functions of the Notice are to give notice that the Minister has received the Petition and to provide an opportunity for interested parties to make submissions on the Petition. As there is no determination made at this stage, it is inappropriate to quash the Notice.

### **The Notice Does Not Bind the Minister or the Cabinet**

[49] Canada argues that, because simply publishing the Notice in the *Gazette* does not bind either the Minister or the Cabinet to any action that is outside either of their jurisdiction, a want of jurisdiction that would ground prohibition is not apparent. Canada notes that the publication of the Notice simply informs the public that the Minister has received the Petition, gives notice as to where the Petition may be inspected, and gives interested parties the opportunity to make submissions on the Petition to the Cabinet. Publishing the Notice does not bind the Cabinet to consider or determine the Petition; the Cabinet is still able at this stage to reject the Petition as being outside its jurisdiction, to hear the Petition and not vary Decision 2010-805, or to hear the Petition and vary Decision 2010-805.

[50] Canada also notes that the roles of the Minister and the Cabinet are distinct. Though the Minister is a member of the Cabinet and as such will take part in the consideration of the Petition, the roles of these two entities are separate under subsection 12(1). The Minister's role in publishing the Notice is purely administrative, while the role of the Cabinet is deliberative. As such, the

Minister's jurisdiction to publish the Notice is separate from the jurisdiction of the Cabinet to hear and decide the Petition. Since the Minister is required to publish the notice under subsection 12(4) regardless of the Cabinet's jurisdiction to hear the Petition, the Notice must stand.

***Certiorari* is Premature When the Action to be Quashed is Interlocutory or Has no Effect on Rights**

[51] Canada argues that for an action to be reviewable by the Court it must have some actual effect on the rights of the parties concerned; where there is no effect to exercising *certiorari*, the remedy should not be granted. In the instant case, publication of the Notice does not affect Bell's rights; Bell can make submissions regarding the Petition to the Cabinet, including submissions on jurisdiction. Further, there is a basic presumption that the courts should not fragment ongoing administrative processes through the granting of prerogative writs, particularly where the granting of the writ may be unnecessary. In the current case, the Cabinet could decline to hear the Petition, based on its determination that it has no jurisdiction to hear it. To seek *certiorari* at this stage is premature and adds an unnecessary element of complexity to the process.

[52] Canada relies on the comments of the Federal Court of Appeal in *Krever*, above, at paragraphs 29 and 30, in this regard:

In principle, therefore, I believe that it is possible to apply to quash a notice that a commissioner decides to give under section 13. In practice, however, I believe that the courts must show extreme restraint before intervening at this stage. The notices in no way state the commissioner's opinion; they merely state the possibility that the commissioner may state the opinion that there has been misconduct. The allegations are not (or should not be) stated in legal language and must not be held under a magnifying glass. When a commissioner decides to include a number of allegations in a single notice, the notice may seem more overwhelming than the final report, in which the findings of misconduct, if such there be, will probably be spread

out. Since a notice, by definition, states possible allegations of misconduct, it is inevitable that it will depict the conduct of its recipient unfavourably, and that the recipient will believe that its reputation is tarnished solely because a notice has been sent to it. Thus there are many reasons why the Court should view the notice in context, and not dramatize its implications.

The courts should intervene only when the content of the notice implies an obvious excess of jurisdiction, or discloses a flagrant breach of the rules of natural justice. [...]

The publication of a notice serves an important public purpose in allowing interested parties to file submissions with the Cabinet while, at the same time, it has very little practical effect on the rights of Bell and therefore the Notice should not be quashed. Further, since quashing the Notice would not prevent the Minister from making a recommendation to the Cabinet under section 13, and would not prevent the Cabinet from hearing and determining the Petition, *certiorari* should not be granted as it would be a meaningless exercise of the Court's discretion.

### **There is no Compelling Reason for the Court to Intervene to Prohibit the Cabinet From Considering the Petition**

[53] Canada argues that Bell has not met the requirements to ground an order of prohibition, as it is not clear that, by hearing and determining the Petition, the Cabinet will step outside its jurisdiction. Because it is clear that the Petition relates to issues determined in Decision 2010-805, that the Cabinet can hear and determine submissions on jurisdictional issues, and that the statutory preconditions for hearing a petition are met, there is no compelling reason for the Court to prohibit the Cabinet from hearing the Petition.

### **No Obvious Want of Jurisdiction**

[54] Canada also notes that subsection 12(1) of the Act vests a broad power to vary decisions of the CRTC in the Cabinet. Further, the only limits on this power are the statutory preconditions of a valid, subsisting decision of the CRTC and compliance with the limitation period. These statutory conditions have been met and so the Cabinet has jurisdiction to consider and determine the Petition. Canada also notes that prohibition is a drastic remedy and should be used with caution; while it is intended and useful for preventing administrative bodies from stepping outside the bounds of their jurisdiction, it should only be used where the lack of jurisdiction is obvious. The Federal Court of Appeal in *Krever*, above, at paragraph 27, quoted de Smith, Woolf and Jowell in *Judicial review of administrative action*, to the effect that “if want of jurisdiction is not apparent, the application must wait until the tribunal has actually stepped outside its jurisdiction.”

#### **The Petition Relates to Determination in CRTC Decision 2010-805**

[55] Canada argues that the only thing that matters in determining if a petition relates to a determination of the CRTC is whether the relief sought in the petition relates to a valid, subsisting, and relevant order of the CRTC. In this case the relief sought in the Petition, the implementation of a competitive bidding process, relates to an explicit rejection of the same process in Decision 2010-805. When the CRTC wrote in relation to its earlier rejection of the competitive bidding process that “these reasons continue to be valid,” it was making a fresh determination on that issue.

[56] Canada also argues that Bell casts Decision 2010-805 too narrowly. Bell has argued that this decision was only about the kind of technology to be used in the expansion of broadband into rural and remote communities. However, in addition to the technology to be used, Decision 2010-805 was also about the allocation of the Deferral Account funds; as the Petition seeks to reduce the

amount of the Deferral Account funds that Bell is permitted to use and to implement a competitive bidding process for the allocation of Deferral Account funds, the Petition relates to the same subject matter as Decision 2010-805. As the Petition relates to the subject matter as the Decision 2010-805, it is within the jurisdiction of the Cabinet to consider it.

### **The Commission Had Authority to Consider Competitive Bidding in Decision 2010-805**

[57] In Decision 2010-805, it was open to the CRTC to institute a competitive bidding process to allocate Deferral Account funds. As sections 60 and 62 of the Act indicate, the power of the CRTC to decide and vary its decisions is broad. Further, there are few constraints on the CRTC's Rate Setting Authority under sections 24, 25 and 32 of the Act which, after the Supreme Court of Canada's decision in *Bell Aliant*, above, includes the power to allocate Deferral Account funds. As such, it was not necessary for Rogers to make a separate application to vary Decision 2010-637 to include a competitive bidding process. Further, the CRTC was not bound to require an amendment to the parties pleadings in the application to vary Decision 2010-637 in order to make a determination on competitive bidding.

[58] Canada argues that where the CRTC's guidelines for review show that to vary a decision an interested party must "demonstrate that there is substantial doubt as to the correctness of the original decision," the fact that the CRTC did not vary Decision 2010-637 in Decision 2010-805 demonstrates that the CRTC did not believe the threshold to vary its earlier decision had been met.

### **No Grounds to Believe the Cabinet Will Act Outside Its Jurisdiction**

[59] Canada notes that the Notice published in the *Gazette* does not indicate that the Cabinet will consider or determine the Petition and, as discussed above, the Cabinet is not bound to consider or determine the Petition. Although the Cabinet might step outside its jurisdiction in hearing the Petition, it is not certain to do so. As the Federal Court of Appeal held in *Singh (Re)*, [1989] 1 FC 430 (FCA); [1988] FCJ No 414 at page 438,

What is important is that the Court should not intervene to prevent a body such as the Commission from carrying out its statutorily mandated duty to enquire into matters which may arguably be within its jurisdiction unless the Court can say with confidence that those matters are not within the Commission's jurisdiction.

In the current case, the Court cannot say with confidence that the matters to be heard by Cabinet are not within its jurisdiction, so the Court should not intervene. Further, as the Cabinet is equipped and capable of hearing and deciding submissions with respect to jurisdiction, the Court should not intervene at this stage.

### **The Cabinet Should be Permitted to Adjudicate the Sufficiency of the Petition Before Judicial Review is Taken**

[60] Because Bell has not exhausted all of the administrative remedies available to it, it is premature for Bell to seek judicial review at this stage. Canada notes that Bell is capable of making submissions to Cabinet with respect to the Petition. As such, Canada argues that the current application for judicial review is a collateral attack on a remedy available under the Act. Canada relies on *C.B. Powell Ltd. v Canada (Border Services Agency)* 2010 FCA 61 at paragraphs 30 and 31 in support of the proposition that all administrative remedies must be exhausted before judicial review may be sought:

The normal rule is that parties can proceed to the court system only after all adequate remedial recourses in the administrative process have been exhausted. The importance of this rule in Canadian administrative law is well-demonstrated by the large number of decisions of the Supreme Court of Canada on point [... ]

Administrative law judgments and textbooks describe this rule in many ways: the doctrine of exhaustion, the doctrine of adequate alternative remedies, the doctrine against fragmentation or bifurcation of administrative proceedings, the rule against interlocutory judicial reviews and the objection against premature judicial reviews. All of these express the same concept: absent exceptional circumstances, parties cannot proceed to the court system until the administrative process has run its course. This means that, absent exceptional circumstances, those who are dissatisfied with some matter arising in the ongoing administrative process must pursue all effective remedies that are available within that process; only when the administrative process has finished or when the administrative process affords no effective remedy can they proceed to court. Put another way, absent exceptional circumstances, courts should not interfere with ongoing administrative processes until after they are completed, or until the available, effective remedies are exhausted.

Because it is within the jurisdiction of the Cabinet to hear submissions on jurisdiction and to decide not to hear the Petition if there is no jurisdiction, there is an administrative remedy available to Bell. Since there remains an adequate administrative remedy, there is no compelling reason for the Court to intervene at this stage.

## **ANALYSIS**

[61] The parties have presented the Court with two antithetical interpretations, or characterizations, of Decision 2010-805. The correct interpretation is important because Bell takes the position that the Petition is invalid because it seeks to vary Decision 2010-805, which involved an entirely different subject-matter, and is in substance an attempt to vary two earlier decisions

(Decisions 2006-9 and 2007-15) outside the one-year limitation period in subsection 12(1) of the Act.

[62] Bell says that Decision 2010-805, which is the alleged subject of the Petition, arose from an application by Bell to vary an earlier CRTC decision ordering it to use its Deferral Account funds to expand wireline broadband services in rural communities. Bell says it applied to the CRTC to vary that decision because it wanted to use wireless rather than wireline technology for the broadband expansion.

[63] Bell complains that Rogers intervened and raised an entirely new issue over Bell's objection: whether the CRTC should hold a competitive bidding process to determine if Rogers could perform the broadband expansion rather than Bell. Rogers had unsuccessfully raised this very issue years earlier in Decisions 2006-9 and 2007-15, when it was rejected by both Cabinet and the CRTC. Bell points out that while Rogers could have appealed, petitioned or applied for review of Decisions 2006-9 and 2007-15 at the appropriate time, it never did.

[64] Bell asserts that the true focus of the Petition is the variation of Decisions 2006-9 and 2007-15 and says that the only relief sought in the Petition is that there be competitive bidding, which the CRTC summarily dismissed in a single paragraph of Decision 2010-805 on the ground that it was already answered by Decisions 2006-9 and 2007-15.

[65] On the basis of this characterization, Bell asks the Court to find that the Petition lies outside Cabinet's jurisdiction because it deals with a different subject-matter (competitive bidding) than the

subject-matter of Decision 2010-805 (Bell's use of its Deferral Account funds for wireless technology). Instead, Bell says it is an attempt by Rogers to evade the one-year ultimate limitation period in subsection 12(1) of the Act for varying Decisions 2006-9 and 2007-15.

[66] On the other hand, Canada and Rogers say that the Petition is clearly related to the subject matter of Decision 2010-805 and is not an attempt to boot-strap the competitive bidding issue that should have been dealt with by other means. Hence, the Cabinet has jurisdiction to deal with the Petition, including the competitive bidding issue.

[67] Bell has directed the Court's attention in particular to paragraph 23 of Decision 2010-805:

With respect to the proposals to allow for competitive bidding in order to ensure the use of least-cost technology, the Commission notes that it rejected this idea both in Telecom Decisions 2006-9 and 2007-50, since it would add a significant layer of complexity, delay the implementation of broadband expansion, and result in substantial administrative and regulatory burden. The Commission considers that these reasons continue to be valid.

[68] Bell says that the CRTC is not here making a fresh decision about competitive bidding; the CRTC is, rather, simply directing the attention of the parties to the fact that the competitive bidding issue has already been dealt with in Decisions 2006-9 and 2007-15. Hence, Bell says that Decision 2010-805 does not deal with competitive bidding and, in asking the Cabinet to address competitive bidding in the Petition, Rogers is again attempting to raise an issue that has already been dealt with in previous decisions and that is not within Cabinet's jurisdiction because it involves different subject matter from Decision 2010-805.

[69] Rogers and Canada, on the other hand, say that the CRTC is making a decision about competitive bidding in Decision 2010-805. The fact that the issue may have been raised and dealt with on previous occasions is irrelevant because the CRTC is not bound by its previous decisions and, in any event, the CRTC has not dealt with the issue in the context of Bell's proposal for HSPA+ wireless services.

[70] Both sides have indicated that paragraph 23 of Decision 2010-805 must be viewed and interpreted in the full context of a series of decisions and debate that goes back to Decision 2002-34 when the CRTC created price regulation frameworks applicable to telecommunications services offered by ILECs, including Bell.

[71] The Court has now reviewed the competing interpretations of Decision 2010-805 offered by the parties. In particular, the Court has been particularly mindful of Decision 2010-805 itself, and what it reveals about the CRTC's intention in referring to competitive bidding in that decision, as well as what the record reveals about the full context and the series of decisions that led up to Decision 2010-805, and what this tells us about whether the CRTC was making a new decision about competitive bidding, or simply directing the parties attention to the fact that the issue had already been dealt with in previous decisions.

### **Decision 2010-805**

[72] To begin with, paragraph 23 of Decision 2010-805 acknowledges that the CRTC has received, as part of the discussion surrounding this decision, "proposals to allow for competitive

bidding in order to ensure the use of least-cost technology....” These proposals are summarized in paragraph 17 of Decision 2010-805:

Barrett, RCI, and Videotron submitted that the revised proposal does not adhere to the principles in the deferral account decisions, as it does not represent the use of least-cost technology to deploy broadband services. These parties argued that alternative broadband service providers could provide a comparable service at significantly less cost than Bell Canada, and submitted that if the Commission approves the revised proposal, it should allow for competitive bidding to see whether other companies could provide the HSPA+ service at less cost.

[73] Paragraph 17 appears in that section of Decision 2010-805 which deals with the following question:

Is Bell Canada’s HSPA+ wireless broadband proposal consistent with the Commission’s criteria for use of funds to expand broadband services in rural and remote areas?

[74] It is apparent from paragraph 17 of Decision 2010-805, in the context of Bell’s application (which was an application to vary Decision 2010-637 by, *inter alia*, allowing the Bell companies to use HSPA+ wireless broadband technology rather than wireline DSL technology in order to provide broadband services to communities previously approved by the commission), that the parties who resisted Bell’s application to vary Decision 2010-637 felt that any such variation would not accord with the CRTC’s established criteria for the use of Deferral Account funds and that, because of this, if the CRTC were to accept the application to vary, it would need to consider competitive bidding “to see whether other companies could provide the HSPA+ service at less cost.”

[75] In other words, on its face, and when the whole of Decision 2010-805 is taken into account, it looks to me as though the CRTC is dealing with an application from Bell to vary a previous

decision (and hence is making a new decision about the use of Deferral Account funds) as part of which the CRTC was asked to consider whether the variations were consistent with its own previously established criteria and whether, if it was disposed to grant Bell its new or revised proposal, it should not also allow for competitive bidding to see whether other companies could provide the HSPA+ service at less cost.

[76] The CRTC points out in Decision 2010-805 that it had previously addressed the issue of competitive bidding in Decisions 2006-9 and 2007-15 and rejected the idea. But Decisions 2006-9 2007-15 were not made in a context where the CRTC was being asked to consider a Bell application for the use of HSPA+ wireless technology.

[77] Hence, in the context of Decision 2010-805, I cannot read the CRTC's comment in paragraph 23 that "it rejected [competitive bidding] both in Telecom Decisions 2006-9 and 2007-50 [sic]..." as an indication that it does not need to, and has not, considered the proposals for competitive bidding as put forward by Barrett, RCI, and Videotron, in the context of Bell's application to vary involving a shift to HSPA+ wireless technology. In my view, all that paragraph 17 says is that competitive bidding was rejected in Decisions 2006-9 and 2007-15 because the CRTC thought "it would add a significant layer of complexity, delay the implementation of broadband expansion, and result in substantial administrative and regulatory burden." The CRTC also considers the same reasons to be valid in the context of Decision 2010-805 even though, as the opposers had pointed out, Bell's application to vary was not consistent with the CRTC's own criteria and, if the CRTC was willing to proceed with the variations, it should allow for competitive

bidding as a way of remaining consistent with the Policy Direction and its own previously stated objectives and criteria.

[78] Hence, I think that the issue of competitive bidding was very much a part of a new decision that the CRTC made in Decision 2010-805 with regards to the application that Bell was making at that time and which involved the use of HSPA+ wireless technology. I do not see how the CRTC could be saying that, for purposes of the application before it, the issue of competitive bidding had already been dealt with in Decisions 2006-9 and 2007-15 and so required no further consideration in the context of an application that now proposed using HSPA+ technology. The HSPA+ decision is one the CRTC had not made before, so the CRTC was required to consider the impact on competition in this context. In my view, the CRTC is simply saying that the justifications it offered earlier in Decisions 2006-9 and 2007-15 to reject competitive bidding are equally persuasive in the decision it is now making. Bell is, in effect, saying to the Court that the CRTC rejected the idea of competitive bidding in previous decisions that did not involve HSPA+ wireless technology and so did not need to, and did not, consider the idea of competitive bidding in an application that does involve HSPA+ wireless technology. I cannot accept this logic, and I do not think this is what the CRTC did in Decision 2010-805. Just because the CRTC references previous decisions for reasons why competitive bidding is not appropriate in the context of a new application involving a new technology, does not mean it has not considered the idea of competitive bidding as part of that new application which involves an assembly of elements that had not previously been before the CRTC.

### **The Wider Context**

[79] I believe that this interpretation is also borne out by the wider context in which Decision 2010-805 was made. By and large, my review of the record before me confirms the rationale and sequencing recited by Rogers and endorsed by Canada.

[80] By the time of Bell's new application, or application to vary (either of them requiring a new exercise of discretion and a new decision from the CRTC) that resulted in Decision 2010-805, Rogers and the other challengers to Bell's application had made it clear to the CRTC that, in their view, an acceptance of Bell's proposal would result in inconsistency with the CRTC's own criteria and principles as forged and articulated in previous applications and decisions. This would require rejection of Bell's application, or a reconsideration of issues such as competitive bidding, in order to maintain competitive neutrality (a CRTC principal) in this market. The CRTC, as Decision 2010-805 shows, disagreed and, *inter alia*, rejected the proposal that competitive bidding was a necessary or desirable approach.

[81] Following Decision 2010-805, Rogers still felt that the CRTC had violated its own principles and that, if Bell's HSPA+ application were to be endorsed, then a reconsideration of competitive bidding was required. In my view, this is what the Petition, in essence, says, and as such it is directly and obviously related to Decision 2010-805. Among other things, the Cabinet needs to consider whether it was appropriate for the CRTC to reject competitive bidding in a context that involved a new technology, a service that is already available in most of the communities involved, and the change of conditions that has occurred since the CRTC rejected competitive bidding in Decisions 2006-9 and 2007-15. The request to the Cabinet in the Petition to consider competitive

bidding as a way of achieving competitively neutral regulation is, in my view, directly related to Decision 2010-805 and, in particular, paragraphs 17 and 23 of that decision.

[82] On 26 January 2011, Rogers submitted the Petition to the Cabinet seeking a variance of the decision. The Petition challenges the CRTC's determination in the decision that Bell's new wireless HSPA+ technology proposal satisfies the CRTC's criteria for Deferral Account funding, including the CRTC's underlying determinations in the decision on the availability of HSPA+ services in the approved locations and the distortion of the wireless market caused by approval of Bell's new proposal, as well as the CRTC's rejection in the decision of a competitive bidding process.

[83] The Petition requests the Cabinet to vary Decision 2010-805 and to affirm that approval of Bell's new wireless HSPA+ technology proposal would give rise to competitive inequities and market distortions that are not consistent with the principles established by the CRTC in earlier decisions and the Cabinet's Policy Direction, and that use of a competitive auction is necessary to satisfy the requirements of competitive neutrality and least-cost provision of service. Recognizing, however, the importance of ensuring that there is no further delay in broadband expansion, the Petition proposes that Decision 2010-805 be varied so as to approve Bell's use of Deferral Account funds to extend service to the locations Bell has proposed to serve in 2011 using HSPA+ technology and to state that a competitive auction will be convened to establish the appropriate Deferral Account subsidy for the extension of broadband service to the remaining approved communities that Bell has proposed to serve.

[84] I agree with Rogers and Canada that the decision speaks for itself on its subject matter. In the decision and in response to the record before it, the CRTC addressed whether Bell's new wireless HSPA+ technology proposal was consistent with its criteria for use of Deferral Account funds for broadband expansion to rural and remote communities in light of a number of factors, including the competitive impact of Bell's proposal and the costs of using a competitive bidding process. The CRTC's approval of Bell's new wireless HSPA+ proposal was integrally related to and based on the CRTC's "determinations" on these factors. This is plainly set out in the "Commission's analysis and determinations" in paragraph 21 to 24 of the Decision:

With regard to the parties' submission that HSPA services are already available in some of the approved communities, the Commission notes that, in order to ensure a fair, predictable, and transparent process, it established 19 February 2007 as the cut-off date for alternative broadband service providers to verify that they were offering, or were planning to offer, broadband service in the communities. The Commission notes that broadband service was not available in the communities in question as of this cut-off date. Furthermore, the Commission notes that none of the carriers providing HSPA service in the approved communities demonstrated that their current offerings are comparable to Bell Canada's revised proposal.

Regarding the parties' concerns that the revised proposal would distort the mobile voice market, the Commission notes that mobile voice services are already available in the vast majority of the 112 approved communities. Furthermore, the Commission considers that there are many economic and social benefits associated with access to broadband services in these communities, and that any associated market distortion would be minimal.

With respect to the proposals to allow for competitive bidding in order to ensure the use of least-cost technology, the Commission notes that it rejected this idea in both Telecom Decisions 2006-9 and 2007-50, since it would add a significant layer of complexity, delay the implementation of broadband expansion, and result in substantial administrative and regulatory burden. The Commission considers that these reasons continue to be valid.

**In light of all of the above**, the Commission finds that Bell Canada's HSPA+ wireless broadband proposal is consistent with its determinations in the Deferral Account decisions. The Commission therefore **approves** the revised proposal. [Some emphasis added.]

[85] As Bell and Canada point out, the Petition challenges and seeks a variance of the CRTC's determinations in Decision 2010-805 on the impact of approving Bell's new proposal on wireless competition, the costs and benefits of implementing a competitive bidding process and the consequent approval of Bell's new wireless HSPA+ technology proposal.

[86] Simply put, paragraphs 21 to 24 of the Decision are the subject matter of the Petition.

### **Bell's Arguments**

[87] Bell has sought to persuade the Court that the above interpretation of the Petition, Decision 2010-805, and the background decisions is not correct for various reasons. In my view, none of the objections put forward by Bell can withstand scrutiny.

[88] First, Bell maintains that the "the CRTC had already fully considered the competitive bidding issue in Decisions 2006-9 and 2007-15." As a matter of law, however, it is my view that while the CRTC may refer to and take guidance from its earlier decisions, those decisions cannot dictate its subsequent decisions. The CRTC is not bound by precedent and has a legal obligation not to fetter its discretion. As stated in Macauley and Sprague's *Practice and Procedure Before*

*Administrative Tribunals*:

... the notion of *stare decisis* is not applicable in the administrative sphere. **Agencies are not only at liberty not to treat their earlier decisions as precedent, they are positively obligated not to do so.** [emphasis added]

[89] The principle that an administrative tribunal cannot use its previous decisions to fetter its discretion was established in *Hopedale Developments Ltd. v Oakville (Town)* (1965), 47 DLR (2d) 482 (ONCA) at 486. The Ontario Court of Appeal held in that case that it would have been an error of law for the Ontario Municipal Board to use precedent to limit the number of issues that it needed to address. Administrative tribunals are permitted to rely on principles articulated in previous decisions as long as the tribunal gives “the fullest hearing and consideration to the whole problem before it.”

[90] The prohibition on exclusive reliance by an administrative tribunal on previous decisions includes not only factual and policy decisions but also legal determinations and is essential to ensure that administrative tribunals have the flexibility to respond to new circumstances on a case-by-case basis. The need for flexibility is particularly acute in the case of policy and factual determinations, such as those at issue in Decision 2010-805 and the Petition.

[91] The CRTC also did not have before it in its previous decisions Bell’s new wireless HSPA+ technology proposal, which Bell characterized as establishing new facts, resulting in a new application. In my view, the CRTC could not have considered competitive bidding in light of these new facts in its previous decisions anymore than the CRTC could have considered Bell’s new wireless HSPA+ technology in its previous decisions. The relevant facts, quite simply, were not previously before the CRTC.

[92] Therefore, in my view, the CRTC cannot, as a matter of law, have “fully considered” in previous decisions whether competitive bidding should be used to allocate Deferral Account funds in light of Bell’s new wireless HSPA+ technology proposal.

[93] Second, Bell argues that consideration of a competitive bidding process was not “properly before the CRTC in the Decision” because Rogers “intervened” and raised this issue “over Bell’s objection.” In support of this proposition, Bell cites jurisprudence on the ability of the interveners to raise new issues at trial and on appeal in the courts. In my view, this jurisprudence has no application to administrative proceedings. Even if it did, Rogers, Barrett and Videotron – all of whom requested a competitive bidding process should Bell’s application be granted – were not interveners; they were interested parties to Decisions 2010-637 and 2010-805, entitled to respond to Bell’s application based on factual, policy, and legal grounds relevant to the CRTC’s assessment of whether Bell’s new wireless HSPA+ technology proposal satisfied the CRTC’s criteria for Deferral Account funding. Opposing parties’ submissions focused specifically on these criteria, including in particular the objectives of extending service to underserved communities, competitive neutrality and least-cost service provision, and it is in this context that the CRTC’s addressed these arguments.

[94] I agree with Rogers and Canada that there was also no prohibition under the former *CRTC Telecommunications Rules of Procedure* (and there is no prohibition under the new *CRTC Rules of Procedure*) on an interested party to a CRTC proceeding to raise policy, factual or legal arguments that have not been expressly identified by an applicant in the application. Rules 13 and 27 of the former *CRTC Telecommunications Rules of Procedure*, cited by Bell, simply provide the CRTC with the discretion to require parties to clarify issues in dispute or to order amendments necessary

for determining the real question in issue. No such steps were taken by the CRTC in the Decision 2010-805 proceeding.

[95] Nor was there any requirement, in my view, for Rogers or other interested parties to “formally request” a variance of Decisions 2006-9 and 2007-15 in their submissions in the Decision 2010-805 proceeding or by separate application. The submissions of opposing parties identify competitive neutrality and competitive bidding as factors that the CRTC needed to consider in its assessment of whether Bell’s new wireless HSPA+ technology proposal was consistent with its criteria for Deferral Account funding.

[96] There is also no question, in my view, that the CRTC had the authority to order the implementation of a competitive bidding process in the Decision had it determined that this was necessary to ensure competitive neutrality and/or least-cost provision of service. In this regard, section 60 of the Act especially authorizes the CRTC to “grant the whole or any portion of the relief applied for in any case, and may grant any of the relief in addition to or in substitution for the relief apply for as if the application had been for that relief.”

[97] Bell’s third proposition is that “the text of Decision 2010-805 does not suggest that the CRTC intended to render any new decision on competitive bidding.” As I have said previously, it is my view that the Decision clearly and unequivocally makes a decision on this issue. In the Decision, the CRTC analyzed and determined the appropriateness of implementing a competitive bidding process, as it was required by law to do, referencing its earlier determinations that such a process would result in complexity, delay and substantial administrative and regulatory burden and concluding that “these reasons continue to be valid.”

[98] I do not think this can be characterized as a “courtesy response” in correspondence to a request for a review or clarification of its earlier decisions. The Decision is identified as “Telecom Decision CRTC Decision 2010-805” and is plainly a decision of the CRTC in all respects. In this regard, the following statement of Justice Noël in *Dumbrava*, above, is instructive:

Whenever a decision-maker who is empowered to do so agrees to reconsider a decision on the basis of new facts, a fresh decision will result whether or not the original decision is changed, varied or maintained. **What is relevant is that there be a fresh exercise of discretion, and such will always be the case when a decision-maker agrees to reconsider his or her decision by reference to facts and submissions which were not on the record when the original decision was reached.** [emphasis added]

[99] The CRTC was empowered to and did expressly reconsider its previous decisions on competitive bidding in Decision 2010-805 as it was legally obligated to do in light of the new facts and arguments before it. These facts and arguments, including Bell’s new wireless HSPA+ technology proposal and the submissions of interested parties, were not before the CRTC in Decisions 2006-9 or 2007-15. The CRTC’s determination that its reasons for declining to use a competitive bidding process in earlier decisions “continue to be valid” does not make Decision 2010-805 any less a decision of the CRTC. What matters is whether CRTC made a fresh exercise of discretion, which, in my view, it did.

[100] I also agree with Rogers and Canada that, as a purely practical matter, the CRTC could not have decided in earlier decisions that its analysis in those decisions would “continue” to be valid in a future proceeding, conducted 3-4 years later to assess a fundamentally different technology proposal for expanding broadband service to rural and remote communities. As discussed above, Bell itself characterized its application as a new application, on the grounds that its new wireless

HSPA+ technology proposal involved new facts not previously before the CRTC. The CRTC could not have previously assessed the appropriateness of using a competitive bidding process in light of these new facts.

[101] Bell also says that, in essence, the Petition is nothing more than a collateral attack on earlier decisions that has been brought out of time. It is true that the record shows that Rogers did threaten to attack and petition Cabinet on similar grounds and using wording that can also be found in the Petition. In my view, however, the fact that Rogers may have threatened to attack earlier decisions but did not follow through on those threats does not make the present Petition a time-barred collateral attack upon those earlier decisions. It is hardly surprising that similar wording is used, or that previous decisions are cited, when the concerns raised are the same. But the fact is that those earlier decisions did not involve the HSPA+ wireless technology and in Decision 2010-805 the CRTC was asked to exercise its discretion anew by addressing that new technology and whether allowing its deployment now gave rise to a need for competitive billing in order to ensure neutrality and compliance with the CRTC's own policies and principles.

### **Conclusions**

[102] I think that the conclusions I have reached at this point effectively deal with the application, and that there is no need to consider additional points raised by Bell or Canada. The heart of Bell's application is that Decision 2010-805 does not contain a fresh exercise of the CRTC's discretion to consider, or reconsider, competitive billing. In my view, it does involve a fresh exercise of that discretion. Hence, the Petition does not deal with subject matter that is unrelated to the Decision and

is not out of time. Consequently, in my view, there are no jurisdictional issues that would justify quashing and setting aside the Notice and/or prohibiting the Cabinet from considering the Petition in accordance with the Act.

**JUDGMENT**

**THIS COURT'S JUDGMENT is that**

1. The application is dismissed.
2. Rogers and the Minister shall have their costs in this matter.

“James Russell”  
\_\_\_\_\_  
Judge

**FEDERAL COURT**

**SOLICITORS OF RECORD**

**DOCKET:** T-514-11

**STYLE OF CAUSE:** **BELL CANADA  
and  
ATTORNEY GENERAL OF CANADA,  
MINISTER OF INDUSTRY and ROGERS  
COMMUNICATIONS INC.**

**PLACE OF HEARING:** Ottawa, Ontario

**DATE OF HEARING:** September 12, 2011

**REASONS FOR JUDGMENT  
AND JUDGMENT** **Russell J.**

**DATED:** September 29, 2011

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FOR THE RESPONDENT

*Court of Appeal for British Columbia*

IN THE MATTER OF THE UTILITIES COMMISSION ACT  
S.B.C. 1980, C.60 AS AMENDED AND IN THE MATTER  
OF AN APPLICATION BY BRITISH COLUMBIA HYDRO  
AND POWER AUTHORITY TO AMEND ITS ELECTRIC  
TARIFF RATE SCHEDULES (THE "APPLICATION")

BETWEEN:

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

APPLICANT  
(APPELLANT)

AND:

THE BRITISH COLUMBIA UTILITIES COMMISSION,  
BRITISH COLUMBIA ENERGY COALITION, CONSUMER'S  
ASSOCIATION OF CANADA (B.C. BRANCH) ET AL,  
COUNCIL OF FOREST INDUSTRIES, WEST KOOTENAY  
POWER LTD., B.C. GAS UTILITY LTD., ISCA  
MANAGEMENT LTD., and RICK BERRY

RESPONDENTS

Before: The Honourable Mr. Justice Goldie  
The Honourable Madam Justice Prowse  
The Honourable Madam Justice Newbury

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Intervenor, Council of Forest Industries et al

Place and Date of Hearing: Vancouver, British Columbia  
February 15, 1996

Place and Date of Judgment: Vancouver, British Columbia  
February 23, 1996

Written Reasons by:

The Honourable Mr. Justice Goldie

Concurred in by:

The Honourable Madam Justice Prowse

The Honourable Madam Justice Newbury

# *Court of Appeal for British Columbia*

BRITISH COLUMBIA HYDRO AND POWER AUTHORITY

v.

THE BRITISH COLUMBIA UTILITIES COMMISSION, BRITISH COLUMBIA ENERGY COALITION, CONSUMER'S ASSOCIATION OF CANADA (B.C. BRANCH) ET AL, COUNCIL OF FOREST INDUSTRIES, WEST KOOTENAY POWER LTD., B.C. GAS UTILITY LTD., ISCA MANAGEMENT LTD., and RICK BERRY

## **Reasons for Judgment of Mr. Justice Goldie:**

1           This is an appeal, by leave, from Order G-89-94 of the British Columbia Utilities Commission (the "Commission") with reasons for the decision attached. I refer to these reasons as the "Decision" and to Order G-89-94 as the "Order".

2           After a public hearing the Commission released the Decision on 24 November 1994. Notice of an application for leave to appeal to this Court was filed by B.C. Hydro on 22 December 1994. Leave was granted 15 December 1995, the day the application was heard. The delay occurred when the Commission acceded to B.C. Hydro's application that it reconsider the Order and Decision. The reasons denying reconsideration were released on 17 October 1995. These proceedings accounted for much of the delay between the filing of the notice of application for leave to appeal and the granting of leave.

3           The issue, as stated by the appellant British Columbia Hydro and Power Authority ("B.C. Hydro"), is whether the Commission exceeded its jurisdiction in respect of certain directions in the Decision given the force of a Commission order. While it is common ground the standard of review in respect of jurisdiction is that the Commission must be correct in its interpretation of its constituent statute, the respondents contend the Commission acted within its jurisdiction and the appeal should be dismissed as no palpable and overriding error has been demonstrated that would permit this Court's intervention.

Background - General

4           B.C. Hydro is a publicly owned utility generating, transmitting and distributing electrical energy. With few exceptions its service area is province wide. Its rates are subject to approval by the Commission under the provisions of the *Utilities Commission Act*, S.B.C. 1980, c. 60 as amended (the "*Utilities Act*"). Under s.3.1 of the *Utilities Act* the Lieutenant Governor in Council may issue a direction to the Commission specifying the factors, criteria and guidelines the Commission is to observe in respect of B.C. Hydro. Such a direction, Special Direction No. 8, was in force at the time material to this appeal.

5           By virtue of the *Hydro and Power Authority Act*, R.S.B.C. 1979, c. 188 as amended (the "*Authority Act*"), B.C. Hydro is for all its purposes an agent of the Queen in Right of the Province; is deemed to have been granted an energy operation certificate for the purposes of the *Utilities Act* in respect of its works existing on 11 September 1980; and is not bound by any statute or statutory provision of the Province except what is made applicable to it by Order in Council. The Minister of Finance is its fiscal agent. The *Utilities Act* is among those ordered to be applicable to B.C. Hydro except sections dealing with one aspect of reserve funds; one enforcement provision and those requiring Commission approval of security issues and property disposition.

6           Section 5 of the *Authority Act* provides that the directors of B.C. Hydro, appointed by the Lieutenant Governor in Council, shall manage its affairs. The powers of B.C. Hydro include the generation, manufacture, distribution and supply of power and the development of power sites and power plants. The exercise of these powers is subject to the approval of the Lieutenant Governor in Council. A further distinction between B.C. Hydro and investor-owned utilities is that B.C. Hydro's sole "shareholder" and not its directors determines when and in what amounts "dividends" will be paid.

7 Under s-s.4 of s.141 of the *Utilities Act*, which came into force 11  
September 1980, the rates of B.C. Hydro then in effect became its  
lawful, enforceable and collectible rates.

8 Prior to 30 June 1995 Part 2 of the *Utilities Act* provided an  
approval process of generating and transmission facilities by the  
Lieutenant Governor in Council which could, at the latter's  
discretion, bypass the Commission. In this event the Commission  
might be called upon to approve rates reflecting the capital costs  
of large scale projects without the opportunity to pass upon the  
adequacy of the information justifying the construction of such  
projects as contemplated by the requirement under s.51(1) of the  
*Utilities Act* requiring a certificate of public convenience and  
necessity prior to embarking upon construction. This provision is  
of some importance and I set it out here:

51. (1) Except as otherwise provided, no person shall,  
after this section comes into force, begin the  
construction or operation of a public utility plant or  
system, or an extension of either, without first  
obtaining from the commission a certificate that public  
convenience and necessity require or will require the  
construction or operation.

9 This prospect has been removed by amendments, primarily to  
Part 2 of the *Utilities Act*, and with it any justification for concern  
over multi million dollar additions to the property devoted to  
public service without prior regulatory scrutiny.

Background - "Integrated Resource Plan Guidelines"

10           In February, 1993 the Commission issued a 12-page document, to which I will refer as the "Guidelines", entitled "Integrated Resource Planning ("IRP") Guidelines". The following is the Definition section of the Guidelines:

**II    DEFINITION**

IRP is a utility planning process which requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional supply sources and those which focus on conservation and the management of demand<sup>1</sup>. The process results in the selection of that mix of resources which yields the preferred<sup>2</sup> outcome of expected impacts and risks for society over the long run. The IRP process plays a role in defining and assessing costs, as these can be expected to include not just costs and benefits as they appear in the market but also other monetizable and non-monetizable social and environmental effects. The IRP process is associated with efforts to augment traditional regulatory review of completed utility plans with cooperative mechanisms of consensus seeking in the preparation and evaluation of utility plans. The IRP process also provides a framework that helps to focus public hearings on utility rates and energy project applications.

1           Referred to as Demand-Side Management (DSM)

2           The term "preferred" is chosen to imply that society has used some process to elicit social preferences in selecting among energy resource options. Unfortunately, there is rarely agreement on the best process for eliciting social preferences. Candidate processes in a democracy include public ownership with direction from cabinet or a ministry, regulation by a public tribunal, referendum, and various alternate dispute resolution methods (e.g. consensus seeking stakeholder collaboratives).

11 In the Purpose section the Commission stated the Guidelines were:

... intended to provide general guidance regarding BCUC expectations of the process and methods utilities follow in developing an IRP. It is expected that the general rather than detailed nature of the proposed guidelines will allow utilities to formulate plans which reflect their specific circumstances.

12 The Commission's identification of the objectives of this process was stated in these words:

1. Identification of the objectives of the plan

Objectives include but are not limited to: adequate and reliable service; economic efficiency; preservation of the financial integrity of the utility; equal consideration of DSM and supply resources; minimization of risks; consideration of environmental impacts; consideration of other social principles of ratemaking<sup>3</sup>, coherency with government regulations and stated policies.

Footnote 3 provides in part:

... The general implication is that because of social and environmental objectives, the rates charged by utilities may be allowed to diverge from those that would result from a rate determination based exclusively on financial least cost. The social principles to be addressed may be identified by the utility, intervenors, or government.

13 In Part III of the Guidelines defining the relationship between regulated utilities and the Commission under the Integrated Resource Plan Process the following sentences occur:

IRP does not change the fundamental regulatory relationship between the utilities and the BCUC. Thus IRP guidelines issued by the BCUC do not mandate a specific outcome to the planning process nor do they mandate specific investment decisions. ... Under IRP,

utility management continues to have full responsibility for making decisions and for accepting the consequences of those decisions. ... Consistency with IRP guidelines and the filed IRP plan will be an additional factor that the BCUC will consider in judging the prudence of investments and rate applications, although inconsistency may be warranted by changed circumstances or new evidence.

14 We are not called upon to determine whether the Guidelines, as defined above, are an appropriate exercise of the Commission's regulatory powers under the *Utilities Act* nor is there an appeal from any part of the Order disposing of B.C. Hydro's application to vary its rates.

15 What is objected to is the manner in which the Commission has purported to give the Guidelines the force of a Commission order. It is convenient at this point to set out the substantive part of Order G-89-94:

**NOW THEREFORE** the Commission, for reasons stated in the Decision, orders as follows:

1. The applied for 2.8 percent increase in rates is denied and the interim increase authorized by Order No. G-18-94 effective April 1, 1994 is to be refunded, with interest calculated at the average prime rate of the principal bank with which B.C. Hydro conducts its business. B.C. Hydro is to provide the Commission with a detailed reconciliation schedule verifying the refund.
2. Rate design changes required by the Decision are to be implemented.
3. An Integrated Resource Plan and Action Plan are to be filed for approval by June 30, 1995.

4. The Commission will accept, subject to timely filing by B.C. Hydro, amended Electric Tariff Rate Schedules which conform to the terms of the Commission's Decision. B.C. Hydro will provide all customers, by way of an information notice and media publication, with the Executive Summary of the Commission's Decision.

4.(sic)B.C. Hydro will comply with all other directions contained in the Decision accompanying this Order.

(emphasis added)

16 I shall refer to the directions identified in the last paragraph as the "Directions". And it is paragraph 4 (sic) of the Order that is in issue here. Counsel for B.C. Hydro says there are 15 Directions related to the Guidelines covered by this paragraph.

17 The principal relief sought, as stated in B.C. Hydro's factum, includes a declaration "... that the IRP related aspects of Order G-89-94 and of the November Decision are void and of no effect".

18 In my view, the Direction best illustrating the issue raised by B.C. Hydro is that which requires it to establish what is called a collaborative committee (the "Committee") together with those Directions determining the part this Committee is to play in B.C. Hydro's performance of its statutory obligation under s.44 of the *Utilities Act* to provide service to the public.

Discussion

19 Mr. Moseley on behalf of the Commission asserted it was doing no more than obtaining information it was entitled to, in a format it could by law determine, all at a time it was authorized to stipulate.

20 There can be little doubt, from the nature of B.C. Hydro's business, the magnitude of financial resources required and the variety of other resources directly or indirectly committed or affected that virtually every person in the Province will have an interest in the management of that business.

21 The Direction in question follows a finding that B.C. Hydro had not complied with the Guidelines "... which require an explicit decision-making process which includes public involvement." B.C. Hydro had in place a public consultation program but this was considered inadequate as being "after the fact" rather than participatory in the planning process. The membership of the Committee was determined by the Commission, apparently on the principle that the planning process is enhanced by the participation of interest groups. This appears from the following observation in the Decision:

Determination of the appropriate trade-offs between resources requires that the values the public attaches to these costs and benefits must be determined and factored into the decision in an explicit and transparent way.

The Commission has made it clear that such values are best determined through the direct participation of representative interest groups.

Exclusive reliance on the B.C. Hydro staff, managers and Board of Directors for resource selection is also unacceptable for another reason. A closed, in-house process has the appearance of, and real potential for, bias in decision making that favors the interests of the bureaucracy within the Utility.

The Committee as constituted following the Order and Decision consisted of two representatives of B.C. Hydro and 11 representing a variety of interests. Each of the 11 spoke for his or her group. Some were regional, others represented classes of customers. One or two represented people who wished to do business with B.C. Hydro.

22           Seven Directions state in detail what B.C. Hydro is to provide the Committee. One includes the following:

Finally, the Commission directs B.C. Hydro to institute with the IRP consultative committee a multi-attribute trade-off analysis for the purposes of portfolio development and selection.

This process is defined in the Commission's glossary of terms:

**Multi-Attribute Analysis** - A method which allows for comparison of options in terms of all attributes which are of relevance to the decision maker(s). In IRP, common attributes are financial cost, environmental impact, social impact and risk.

23           This requires B.C. Hydro to appraise future projects which it may never implement because of, for instance, financial constraints

imposed by the Minister of Finance or by virtue of a special direction under s.3.1 of the *Utilities Act*.

24           There is evidence supporting the following assertion in the appellant's factum:

The bulk of the IRP Directives can be characterized as requiring BCH to put BCH's resource planning initiatives and analyses to the Consultative Committee and be guided by the views and information provided by the members of the Consultative Committee in undertaking its resource planning responsibilities.

25           It cannot be seriously questioned that the Commission requires compliance with its Guidelines: at p.66 of the reasons the Commission concludes a direction denying recovery of a portion of B.C. Hydro's Resource Planning Unit expenditures with these words:

Should the Utility continue to fail to implement the Commission's directions respecting IRP, the Commission will consider the circumstances and may invoke its powers under Part 9 of the Act.

26           Part 9 of the *Utilities Act*, to which I will later refer, includes a list of offences under the *Utilities Act*.

27           B.C. Hydro filed with the Commission on 8 November 1996 what it called its integrated electricity plan which it asserted complied with the Directions in the Decision. The Commission has ordered a public hearing into the integrated electricity plan in February 1996.

28 I restate the question before us. It is whether there is statutory authority for the Commission's imposition of the Guidelines to the extent required by the relevant Directions in the Decision on what is essentially an internal process for which the directors of B.C. Hydro have the ultimate responsibility, both in respect of the process and for the selection of the product of the process.

29 Mr. Sanderson's first point on behalf of B.C. Hydro is that nowhere in the *Utilities Act* is reference made to planning. In answer, Mr. Mosely referred us to s.51(3) which requires a public utility to file annually with the Commission a statement in a prescribed form "... of the extensions to its facilities that it plans to construct". This describes a result at the conclusion of the relevant planning process. In the context of s.51(2) it refers to the construction of facilities for which separate certificates of public convenience and necessity may not be required.

30 In my view, s.51(3) has little relevance to the case at bar. It appears B.C. Hydro routinely files the statement referred to. The amounts in question may be in the aggregate substantial but one would expect many of the expenditures for individual components would not be, as they would relate to the routine reinforcement of transformation and distribution facilities required to meet load growth or to maintain the reliability and adequacy of service.

31 Section 28 of the *Utilities Act* is also relied upon by the respondents. In full, it provides:

**General supervision of public utilities**

28. (1) The commission has general supervision of all public utilities and may make orders about equipment, appliances, safety devices, extension of works or systems, filing of rate schedules, reporting and other matters it considers necessary or advisable for the safety, convenience or service of the public or for the proper carrying out of this Act or of a contract, charter or franchise involving use of public property or rights.

(2) Subject to this Act, the commission may make regulations requiring a public utility to conduct its operations in a way that does not unnecessarily interfere with, or cause unnecessary damage or inconvenience to, the public.

32 Two observations can be made of this section: the first is that the class of matters referred to in s-s.(1) relates to the existing service provided the public as distinct from future service. The second is that s-s.(2) also refers to present service, that is to say, the conduct of operations in relation to the public. Neither of these subsections refers to the utility's plans for the future.

33 Section 29 of the *Utilities Act* has some relevance to the contention that the IRP process comprises in one bundle the exercise of individual powers granted the Commission. It directs the Commission to make examinations and conduct inquiries necessary to keep itself informed about, amongst other things, the conduct of

public utility business. It does not authorize the Commission to direct how that business is conducted.

34           The Commission is supplied with B.C. Hydro's load forecasts as is apparent from its comments in the Decision. These dictate the response a utility must make to meet its statutory obligation to provide service as well as to maintain compliance with the terms of existing certificates of public convenience and necessity. It is within this part of the process that the Commission has decided, in its words, to make the IRP the "... driving force behind the establishment of a utility action plan approved by senior management."

35           It appears reasonable to assume the purpose of the Guidelines is to look beyond a simplistic view of utility planning as one limited to selecting the resources needed to meet anticipated demand and in doing so, to reject an equally simplistic view of regulation as ensuring that service is provided at the least cost to the consumer. It has been evident for some years now that environmental considerations are important in the formulation of the opinion represented by the phrase "public convenience and necessity". To the same effect, conservation and management of energy use is now recognized in what is known as demand side management. The wisdom of all this does not appear to be an issue.

36           The Commission's order directs when and how these factors are to be taken into account in the sequence of B.C. Hydro's planning processes.

37           The Commission in its factum asserts the IRP process is designed to accomplish two objectives:

1.   It provides information to the Commission as to the resource selection choice being made by a utility; and
2.   Following a review of the IRP plan for the Commission "... it provides guidance to utility management in the form of an advance indication as to the approach the Commission is likely to apply when it subsequently assesses the prudence of the expenditures made by the utility."

38           It will be noted the first objective refers to choices being made while the second refers to expenditures already made.

39           This dichotomy between present planning and past expenditures is said by the Commission to require regulatory control at the planning stage to avoid the dilemma of disallowing substantial incurred expenditures at the rate review stage. The examples given by the Commission in its reconsideration reasons were a nuclear plant and a large hydro electric dam.

40           Section 51 of the *Utilities Act* avoids this Hobson's choice. It does so by requiring a certificate of public convenience and necessity before the utility begins construction. It is not suggested the Commission has been demonstrably ineffectual in discharging its responsibilities at the certification stage.

41           Other provisions in the Act relied upon by the Commission are as follows:

1.   Section 49 which requires a utility to furnish information to the Commission and answer its questions. This does not require that the utility create information for the purpose of a consultative committee nor to respond to the requests of a consultative committee - both of which have been directed by the Commission.
2.   Sections 64-66 which deal with the Commission's jurisdiction over rates. To the extent these are relevant I have dealt with them in my comment on s.51 of the *Utilities Act*.

42           I am of the view no section of the *Utilities Act* expressly enables the Commission to impose by order its chosen form of controlling planning at the stage selected by it.

43 In this I rely upon the literal meaning of each of the sections in the Act which have appeared to me to have any relevant significance.

44 These are, however, to be construed in relation to the *Utilities Act* as a whole. I refer to what Mr. Justice Beetz said in *UES, Local 298 v. Bibeault*, [1988] 2 S.C.R. 1048 at 1088 as the initial stage in a pragmatic or functional analysis:

At this stage, the Court examines not only the wording of the enactment conferring jurisdiction on the administrative tribunal, but the purpose of the statute creating the tribunal, the reason for its existence, the area of expertise of its members and the nature of the problem before the tribunal.

45 The premise of such an analysis is that it focuses on jurisdiction: did the legislature intend the question in issue to be answered by the courts or by the tribunal? It is a matter of statutory interpretation with the emphasis on purpose.

46 In this light the *Utilities Act* is a current example of the means adopted in North America, firstly in the United States, to achieve a balance in the public interest between monopoly, where monopoly is accepted as necessary, and protection to the consumer provided by competition. The grant of monopoly through certification of public convenience and necessity was accompanied by the correlative

burden on the monopoly of supplying service at approved rates to all within the area from which competition was excluded.

47           It is self-evident this process cannot be undertaken on a day to day basis by legislature or government. Hence, the creation of public utilities commissions. In the United States a constitutionally acceptable formula was evolved to protect the grantee of a certificate of public convenience and necessity from rates so low they constituted piece-meal confiscation of property without due compensation. The form this took was adopted in Canada. A brief historical sketch, relevant to this province, is found in the concurring judgment of Mr. Justice Locke in *British Columbia Electric Railway Co. Ltd. v. The Public Utilities Commission*, [1960] S.C.R. 837 at 842-845. The *Utilities Act* contains many expressions linking it with its legislative antecedents.

48           The certification process is at the heart of the regulatory function delegated to the Commission by the legislature. In *Memorial Gardens Association Ltd. v. Colwood Cemetery Co.*, [1958] S.C.R. 353 Mr. Justice Abbott, after referring to the American origin of the phrase, said at 357:

As this Court held in the *Union Gas* case, *supra*, the question whether public convenience and necessity requires a certain action is not one of fact. It is predominantly the formulation of an opinion. Facts must, of course, be established to justify a decision by the Commission but that decision is one which cannot be made without a substantial exercise of administrative

discretion. In delegating this administrative discretion to the Commission the Legislature has delegated to that body the responsibility of deciding, in the public interest, the need and desirability of additional cemetery facilities, and in reaching that decision the degree of need and of desirability is left to the discretion of the Commission.

49           The other function the legislature has entrusted to the regulatory tribunal is the supervision of the utility's use of property dedicated to service as a result of the certification process. Unless so certified, or exempted from certification by the Commission, such property is not part of the appraised value of the utility company under s.62(1) which is the basis for fixing a rate under s.66. In respect of such property the supervisory powers of the Commission, principally found in Part 3 of the *Utilities Act*, enable it to oversee the statutory obligation in s.44 to furnish service imposed upon every public utility, namely:

44. Every public utility shall maintain its property and equipment in a condition to enable it to furnish, and it shall furnish, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

50           It is not without some significance that the Commission found in the Decision the following:

From the evidence, the Commission recognizes that B.C. Hydro is generally maintaining a safe, secure and highly reliable generation, transmission and distribution service. Given this high level of reliability, the Commission has focused on cost control as an issue at this time.

51           The *Utilities Act* runs to over 140 sections. The administration of the jurisdiction conferred upon the Commission is amply delineated by express terms. There is no need to imply terms for this purpose.

52           I have already described the reason for the existence of the tribunal. The expertise or skills of its members vary. Experience has demonstrated skills associated with accounting, economics, finance and engineering have been frequently utilized. Unlike labour relations tribunals where past experience in the field of labour relations is a virtual prerequisite, past experience in the regulatory field is not necessary. A similar observation may be made with respect to securities commissions. Both labour relations tribunals and securities commissions are expressly conferred with policy making powers. None such are conferred on the Commission.

53           In considering the nature of the problem before the tribunal I will first deal with the *Utilities Act* as a law of general application. I will then consider whether the provisions of the *Utilities Act* which relate only to B.C. Hydro affect my conclusions.

54           I earlier referred to the characterization of the issue. Counsel for the Commission contended it merely related to the enforcement of the information gathering power conferred on the Commission.

55 I am unable to agree with that characterization as in my opinion the IRP process is specific to the planning phase of the utility's response to its statutory obligations and its enforcement by order is an exercise of management as it relates neither to the certification process as such nor to the supervision of the utility's use of its property devoted to the provision of service.

56 It is only under s.112 of the *Utilities Act* that the Commission is authorized to assume the management of a public utility. Otherwise the management of a public utility remains the responsibility of those who by statute or the incorporating instruments are charged with that responsibility.

57 One of the primary responsibilities and functions of the directors of a corporation is the formulation of plans for its future. In the case of a public utility these plans must of necessity extend many years into the future and be constantly revised to meet changing conditions. In the case at bar the effect of the Commission's directions is to place a group, whose interests are disparate, in a superior position in the sequence of planning and to require the directors to justify a deviation from the product of the IRP process in the exercise of their responsibilities.

58           Taken as a whole the *Utilities Act*, viewed in the purposive sense required, does not reflect any intention on the part of the legislature to confer upon the Commission a jurisdiction so to determine, punishable on default by sanctions, the manner in which the directors of a public utility manage its affairs.

59           When the *Utilities Act* is examined in light of the provisions applicable to B.C. Hydro alone, this conclusion is reinforced. I have mentioned s.3.1. This authorizes the Lieutenant Governor in Council to issue a direction to the Commission specifying "factors, criteria and guidelines" to be used or not used by the Commission in regulating and fixing rates for B.C. Hydro. There is no comparable mandatory power conferred on the Commission to issue such directions to B.C. Hydro. From my examination of the *Utilities Act* this is the only reference to guidelines. A further important exclusion from the jurisdiction of the Commission is its approval of the issue of securities under s.57. Moreover, under s.59 B.C. Hydro may dispose of its property without obtaining the Commission's approval.

60           I have mentioned sanctions and the Commission's threat to resort to Part 9 of the *Utilities Act*. Part 9 lists as an offence on the part of individual officers, directors and managers of utility in the failure to comply with a Commission order.

61 Tested in terms of general principles I am of the view the observations of the Ontario Court of Appeal in *Ainsley Financial Corporation et al v. Ontario Securities Commission et al* (1994), 21 O.R. (3d) 104, (Ont.C.A.) are relevant. In that case the Ontario Securities Commission ("OSC") issued a draft policy statement, subsequently adopted with minor modifications after the action in question had been commenced.

62 This policy statement purported to be a guide to those engaged in the marketing and selling of penny stocks as to business practices the OSC regarded as appropriate. As was set out in greater detail in *Pezim v. British Columbia (Superintendent of Brokers)*, [1994] 2 S.C.R. 557, major securities commissions such as the OSC have a policy role in the regulation of capital markets in the public interest as well as an adjudicative function in applying sanctions in specific cases. The following headnote from *Ainsley* is, I think, relevant to the point before us.

The validity of the policy statement turned on its proper characterization. If the statement was a non-binding statement or guideline intended to inform and guide those subject to regulation, the statement was valid and within the authority of the OSC; guidelines of this nature do not require specific statutory authority and such guidelines are not invalid merely because they regulate in the sense that they affect the conduct of those at whom they are directed. If, however, the statement imposed mandatory requirements enforceable by sanction, then the statement required statutory authority; a regulator cannot issue *de facto* laws disguised as guidelines.

63           The issue of non-mandatory guidelines is not a question before us. Here, I repeat, the Commission has explicitly purported to enforce the application of its directions with the threat of sanctions.

64           In my view, the appellant is entitled to a declaration that the Directions in the reasons for Decision for Order G-89-94 issued 24 November 1994 which ordered the application of the Integrated Resource Plan to British Columbia Hydro and Power Authority are beyond the statutory powers of the Commission and are accordingly unenforceable.

65           I would make no order as to costs.

"The Honourable Mr. Justice Goldie"

**I AGREE:**           "The Honourable Madam Justice Prowse"

**I AGREE:**           "The Honourable Madam Justice Newbury"

Pursuant to s.121 of the *Utilities Commission Act*, the foregoing will be certified as the opinion of the Court to the Commission.

**Court of Appeal for British Columbia**  
**Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)**  
**Date: 1992-03-26**

*Chris W. Sanderson and Barbara Cornish, for appellant.*

*Gordon A. Fulton, for respondent B.C. Utilities Commission.*

*Patrick G. Foy, for respondent Attorney General of British Columbia.*

(Doc. Vancouver CA013604)

March 26, 1992. The judgment of the court was delivered by

CUMMING J.A.:—

DECISION APPEALED FROM

[1] This is an appeal from O. G-11-91 of the British Columbia Utilities Commission (the “commission”) pronounced January 30, 1991 reaffirming the terms of O. G-77-90, made October 17, 1990, which permitted the appellant utility, Hemlock Valley Electrical Services Ltd. (“HVES”), to increase the rate it charges for the supply of electrical services, but ordered that the rate base costs be phased in over a period of three years.

[2] On March 7, 1991, pursuant to s. 115 of the *Utilities Commission Act*, S.B.C. 1980, c. 60, Toy J.A. granted leave to appeal to this court and directed that the operation of commission O. G-11-91 be stayed upon terms to which further reference will later be made.

FACTS

[3] HVES, a wholly owned subsidiary of Hemlock Valley Resorts Inc., is a small, special purpose utility which is the sole supplier of electrical service to a group of approximately 192 residential customers living in a single community located around the Hemlock Valley ski hill in the lower mainland of British Columbia. HVES also provides service to the ski hill itself.

[4] HVES was incorporated in 1979 and on June 20, 1980 was granted a certificate of public convenience and necessity by O. C-23-80 of the British Columbia Energy Commission, the predecessor of the present commission.

[5] On November 13, 1982 HVES filed a rate application with the commission (the “1982 application”). A public hearing was held on June 7, 1983 and the commission rendered its decision on July 8, 1983 (the “1983 decision”).

[6] At that time HVES' operations were described as follows:

Hemlock is a subsidiary of Hemlock Valley Recreations Ltd. ("Hemlock Recreations"), which company owns and leases land in the Hemlock Valley of the Lower Mainland of British Columbia for year-round recreational use. Hemlock provides underground electric service to residential consumers and to Hemlock Recreations for use in a ski lodge, lifts and a maintenance area; to Hemlock Property Management Ltd. for residential use on residential properties; and to Hemlock Valley Sanitary Service Ltd. for a sewer system serving the recreation area. All three companies are wholly owned subsidiaries of Hemlock Recreations.

[7] In the 1983 decision the commission declined to allow HVES a return on its rate base and ordered that electrical rates be set at 11.5¢ per kW.h with a \$15 per month minimum charge, effective July 1, 1983. The commission noted:

- (a) the Hemlock recreational area was still in the developmental stage;
- (b) the development had been materially affected by a downturn in the provincial economy;
- (c) HVES had taken significant steps to reduce the cost of power and improve the reliability of service through the interconnection with B.C. Hydro;
- (d) undertakings were given in the prospectus of Hemlock Valley Estates Limited indicating that a purchaser of property could expect that all services would have been completed and paid for by the developer from its own resources.

[8] The commission concluded that in the circumstances of HVES a reasonable approach to rates would be based on a break-even approach between revenue and expenses.

[9] In its decision of October 17, 1990 the commission said of the 1983 decision:

It is clear that in the 1983 decision the interdependency of electric and other services with the resort enterprise at Hemlock Valley was fully understood. It is also clear that the commission felt some consternation about the 7.69 per cent negative return on rate base flowing from the 1980 decision. It was also apprehensive that the continued existence of Hemlock Valley as a going concern was being "materially affected by the downturn in the provincial economy." Moreover, it was looking at the changeover from diesel generators to a tie-line with B.C. Hydro. The change in source of power was unquestionably correct in the long-term, but it imposed an annual amortization cost of \$98,840.18 for the years immediately ahead. That addition of nearly \$100,000 per year materially distorted the profit and loss statement. In the circumstances, the commission, in its 1983 decision, chose to ignore return on rate base as an appropriate means of fixing fair and reasonable rates, and chose instead a pragmatic break-even approach between revenue and expenses. It also added a small allowance for contingencies. Management of the utility was evidently prepared to accept this approach.

[10] By commission O. G-65-83, dated August 23, 1983, HVES was again ordered to amend its rates to reflect the sale of a portion of its electric utility plant to B.C. Hydro.

[11] On July 10, 1984 HV Recreations, the parent of HVES, went into receivership. HV Recreations remained in receivership until January 15, 1987 when Skipp L.J.S.C. (as he then was) approved the sale of the assets of HV Recreations, including the HVES shares, to one Michael Robbins or his assignee. Sometime after January 15, 1987 the HVES shares were transferred to Hemlock Valley Resorts Inc. ("HV Resorts"). HV Resorts remains the sole shareholder of HVES. Throughout 1987 and 1988 there were various changes in the ownership of HV Resorts and on October 27, 1988 its shares were acquired by Mr. Joseph Peters. There has been no change in the ownership of the assets or shares of HV Resorts since that date.

[12] In 1984 and again in 1986 increased rates were approved to reflect, firstly, an increase in B.C. Hydro's water rental fees and, secondly, an increase in the cost to HVES of purchasing power from B.C. Hydro.

[13] As of the spring of 1990 the rate being charged by HVES was 8.650 per kW.h. That rate had been in effect since September 26, 1986.

[14] On May 31, 1990 HVES applied to the commission to increase its tariff rates by 7.320 per kW.h, an 84.6 per cent increase. The reasons given were to permit the recovery of recently approved rate increases to B.C. Hydro, forecast operating costs and a return on rate base. In the 1990 application, HVES proposed a rate base of \$366,511 with a 13 per cent return on the debt component and a 15 per cent return on the equity component of that rate base.

[15] Prior to a public hearing the commission, by O. G-58-90, ordered that effective July 1, 1990 HVES be allowed an interim increase of 3.70 per kW.h in its rates to permit the recovery of the increased cost of purchased power from B.C. Hydro and increased operating costs. The operative part of that order read:

1. The Rate Base costs included in the Application will not form part of the interim increase allowed in item No. 2 of this Order at this time.
2. The Commission will accept, subject to timely filing, effective July 1, 1990, an amendment to its Electric Tariff Rate Schedule incorporating an increase of 3.70 cents/kW.h over existing rates on an interim basis, with the interim increase subject to refund with interest calculated at the average prime rate of the bank with which HVES conducts its business.

3. HVES, by way of a Customer Notice, is to inform each customer, as soon as possible, of the application before the Commission, the approved interim increase and the effect on average annual billings. HVES is to provide the Commission with a copy of the Customer Notice.

[16] On August 2, 1990 the commission directed that a public hearing commencing September 24, 1990 be held in respect of HVES' application of May 31, 1990 and gave directions with respect to notice of the hearing and participation by intervenors and interested persons intending to participate in the public hearing.

[17] The Hemlock Valley Ratepayers Association intervened and, we were advised, played a significant role at the hearing. Its submissions covered many areas, correcting a number of statements in the application and disputing a number of forecasts. Among other things, the rate base component in the application was opposed on the basis that the utility systems were fully paid for by the developers.

[18] The commission received evidence of complaints of unsatisfactory service, inadequate HVES accounting documentation, concerns about paying for the recreational commercial venture through utility payments (commercial power use is unmetered), detailed comments on HVES' proposed operating and maintenance expenses, comparisons to residential rates in other areas, and other matters.

[19] Following the public hearing on September 24 and 25, 1990, by commission O. G-77-90 dated October 17, 1990, the commission issued a decision (the "original decision") with respect to the 1990 application.

[20] The operative part of O. G-77-90 reads:

1. The Rate Base and Revenue Requirement for the Test Period are set out in Schedules contained in the Decision.
2. The Commission will accept, subject to timely filing, amended Electric Tariff Rate Schedules which confirm to the terms of the Commission's October 17, 1990 Decision.
3. HVES is to proceed with refunds to its customers of record on and after July 1, 1990, where necessary. Such refunds are to include interest calculated as specified in O. G-51-90.
4. HVES will comply with the several directions incorporated in the Commission Decision.

I have appended as App. A to these reasons [pp. 25-30] the schedules referred to in para. 1 of the commission order.

[21] By the original decision the commission declined to permit the full implementation of the approved rate increase immediately but instead directed that it be phased in by

increases of 1.510 per kW.h effective July 1, 1990, and 1.510 per kW.h and 0.750 per kW.h effective May 1, 1991 and May 1, 1992 respectively.

[22] It is this rate adjustment phase-in which is the principal focus of this appeal.

[23] By letter dated November 8, 1990, HVES requested that the commission reconsider certain aspects of the original decision pursuant to s. 114 of the Act on the basis that:

(a) Reconsideration was appropriate because HVES had not been provided with an opportunity to deal with the phase-in issue in its rate application;

(b) Once the commission had determined that there was a rate base and that a 13 per cent return on it was "just and reasonable," pursuant to the Act, the commission was obliged to permit HVES an opportunity to recover sufficient revenue to capture that return.

[24] On January 30, 1991, by O. G-11-91, the commission ordered that the request by HVES to vary O. G-77-90 be denied and that HVES was to proceed with refunds to customers and to comply with all other directions in that order.

[25] The operative part of O. G-11-91 reads:

Now THEREFORE the Commission orders as follows:

1. The Request, by HVES to vary the October 17, 1990 Commission Decision and Order No. G-77-90, is denied and the Commission's Reasons for Decision is attached as Appendix A.

2. The Commission reaffirms and orders HVES to proceed with refunds to customers along with other directions incorporated in its October 17, 1990 Decision and Order No. G-77-90.

[26] It is from O. G-11-91 that this appeal is taken.

#### GROUNDS OF APPEAL

[27] As set out in the appellant's factum the grounds of appeal are:

that the Commission erred in pronouncing Order No. G-11-91, which reaffirmed Commission Order No. G-77-90 when Order No. G-77-90 contained an error in law ... in that the Order:

(a) failed to permit HVES the opportunity to recover a portion of its rate base costs over three years notwithstanding that the Commission had determined that that portion of its rate base costs was necessary for the establishment of rates which were just and reasonable under the *Utilities Commission Act*, S.B.C. 1980, c. 60 (the "Act");

(b) required a refund of monies which the Commission had determined were necessary to permit HVES an opportunity to receive a just and reasonable rate under the Act.

## REASONS FOR THE DECISIONS OF THE COMMISSION

### 1. *Original Decision*

[28] In the original decision of October 17, 1990, under the heading "Determination of Rate Base," the commission, after reviewing the 1983 decision, went on to say:

This division of the commission considers that the 1983 decision was a practical decision to tide the enterprise at Hemlock Valley over a particularly difficult period. Sooner or later, however, longer-term prospects must be faced squarely. The tie-line has been amortized over five years. Evidence (Exs. 14 through 21) clearly indicates that recovery of plant expenditures was anticipated through utility rates. *Therefore the commission believes that a return to more traditional rate-making practice is justified.*

It was proposed to the commission by the intervenors at the hearing that rate base should not be recognized. The cornerstone of rate base is appraised value of utility property, which is usually taken to be original cost of plant. The commission cannot, by a stroke of the pen, eliminate the appraised value of the property; to do so would be confiscation of property ...

And concluded:

*The commission has considered alternative calculations for rate base and concludes that no material difference results from any refinements which might be made. Therefore, the commission accepts the company's evidence, and finds the rate base to be \$366,511 for the test period.*

[29] The commission then continued:

#### 4.2 *Capital Structure*

The company currently has no viable capital structure of its own. Its financing has been by way of loans from the parent company. The applicant proposes a deemed 50/50 per cent debt/equity ratio in this application. It is a frequent practice of regulatory tribunals to use a notional capital structure. While 50 per cent equity is much higher than would be usual for utilities in general, the higher proportion of equity in this case can be considered as reasonable, bearing in mind the relative risks in the case of the company.

#### 4.3 *Return on Rate Base*

The company has proposed a return of 13 per cent on the debt component, and 15 per cent on the equity component of the rate base. Standing alone, these figures certainly fall within a reasonable range in today's market. Nevertheless, the commission considers it essential to consider the particular circumstances of the company in this decision. While it is true that risky investments typically command higher returns, that position considers primarily the potential investors' point of view in placing funds at the utility's disposal. From the existing shareholders' point of view, the realization of an allowable rate of return depends upon the ability of management to run an efficient organization, and for external factors to favourably affect the prosperity of the company. Bearing in mind the interrelationship of the resort and utility elements at Hemlock, and the current circumstances of the utility, the commission cannot accept a return on equity for rate-making purposes of 15 per

cent. *For the foregoing reasons, the commission believes that a 13 per cent return on debt and a 13 per cent return on equity are both just and reasonable within the spirit of s. 65(3) and (4) of the Act, which states:*

“(3) It is a question of fact, of which the commission is the sole judge, whether a rate is unjust or unreasonable, or whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate of service, or whether a service is offered or furnished under substantially similar circumstances and conditions.

“(4) In this section a rate is ‘unjust’ or ‘unreasonable’ if the rate is

“(a) more than a fair and reasonable charge for service of the nature and quality furnished by the utility,

“(b) insufficient to yield a fair and reasonable compensation for the service rendered by the utility, or a fair and reasonable return on the appraised value of its property, or

“(c) unjust and unreasonable for any other reason.”

[30] Under the heading “Cost of Service” the commission, over several pages, reviewed in detail various components of the cost of service which HVES estimated it would incur and for which it sought a rate sufficient to enable it to recover, and considered the objections to and criticisms of those cost components raised by the intervenors and various witnesses. It is not necessary here to review this aspect of the material in any great detail: it is sufficient to say that where the commission did not accept in full the submissions of HVES it reduced the eligible cost component by the amounts set out in the schedules to its order (see, in particular, sheet 5 of App. 1) with the result that HVES’ revenue requirements, for rate-making purposes, were reduced accordingly. The commission also made a number of directions and recommendations to the company, of which the following are examples:

*The commission directs the company to prepare and file with the commission an operating budget at the beginning of each fiscal year ...*

*The commission therefore directs that the company provide the commission with a time schedule for the completion of the work, as well as specific advice when the work is completed. In addition, the company is directed to file a copy of its preventive maintenance program by November 1, 1990,*

but these did not result in any further adjustments to the estimates of allowable and recoverable costs of service.

[31] The commission then turned its attention to the question of “quality of service” and reviewed a number of complaints and dissatisfactions expressed by the intervenors. It concludes its discussion of this issue by saying:

During the course of the hearing, the commission was impressed with the sincerity, variety and degree of expertise shown by the witnesses for the principal intervenor, the Hemlock Valley Ratepayers’ Association. It is suggested to the company that

consideration might well be given to drawing on this pool of talent. *The commission strongly recommends that a "utility consultation committee" be established by HVES, with members from the utility and representative ratepayers. Quarterly information meetings should serve to improve communications in the interest of the common goals of all the participants on the mountain.*

Apart from the recommendation which the commission made in this passage, nothing else was said by the commission with regard to quality of service and, most importantly, as will be noted later, no further adjustments were made to the rate base, rate of return or the allowable components of recoverable cost of service (other than those specifically referred to) by reason of any concern related to the quality of service provided by HVES to its customers.

[32] The commission summarized its decision as follows:

## 7.0 Decision Summary

### 7.1 Revenue Requirement

Section 44 of the *Utilities Commission Act* requires that:

"44. Every public utility shall maintain its property and equipment in a condition to enable it to furnish, and it shall furnish, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable."

It is the duty of the commission to see that this is done. It is also the duty of the commission to ensure that the utility has sufficient revenue to enable it to perform these functions. However, it must always be satisfied that the level of funding provided for is within the company's ability to use efficaciously.

*On the basis of the evidence presented, the commission has set a revenue requirement to satisfactorily meet the above objectives (refer to attached schedules).*

### 7.2 Rate Adjustment Phase-In

As mentioned in s. 1.0, the application contemplated a rate increase of 84.6 per cent in the test year. The adjustments to the cost of service in this decision have mitigated some of the potential rate shock. The commission considers that a return on rate base should be allowed; however, it believes that the ratepayers should be protected from the full impact initially. In arriving at this conclusion, the commission has recognized that there was a hiatus of some seven years between applications. In addition, the future economics and the viability of the mountain are at stake.

*Accordingly, the commission orders that the rate base costs be phased in over three years. The commission requires the utility to file amended rate schedules incorporating an increase of 1.51¢ per kW.h over permanent rates effective July 1, 1990, and for further increases of 1.51¢ per kW.h and 0.750 per kW.h effective May 1, 1991 and May 1, 1992, respectively.*

## 2. Reconsideration Decision

[33] In refusing the request of HVES for reconsideration and confirming its original decision, the commission said, under the heading "Jurisdiction":

### 2.0 JURISDICTION

The argument made on behalf of HVES has as its essence the jurisdiction of the commission, and it is set out in the letter dated December 14, 1990.

On p. 2 of that letter, s. 65(4) of the Act is quoted in its entirety, as is s. 66(1)(a) and (b). The submission then goes on:

“The words of Section 65(1)(b) [reference should be s. 65(4)(b)] and Section 66(1)(b) of the Act are a clear statutory direction to the Commission on how to determine a just and reasonable rate. In our respectful submission, in the presence of clear language, the Commission may not disregard those statutory provisions and substitute its own opinion of what is just or reasonable in any given case.”

It is the commission’s view that the submission is flawed in that it evidently invites the commission to ignore the clear language of s. 65(4)(a) and (c), and concentrate instead only on s. 65(4)(b) which supports the position of HVES. The commission holds that, in fixing a rate, it must have due regard to the whole of s. 64. Section 66(1)(b) makes this abundantly clear:

“the Commission shall have due regard, among other things, to the fixing of a rate that is not unjust or unreasonable, within the meaning of Section 65.”

[34] After referring to and distinguishing the decision of the Supreme Court of Canada in *British Columbia Electric Railway Co. v. British Columbia Public Utilities Commission*, [1960] S.C.R. 837, 33 W.W.R. 97, 82 C.R.T.C. 32, 25 D.L.R. (2d) 689, the commission continued:

The point which seems to be missed is that the commission’s decision of October 17, 1990 must be taken as a whole and should be read and understood as such. It is not a decision on rate of return, followed by decisions at a later time on other matters. The phase-in is an integral part of the finding on just and reasonable rates. The decision as a whole should make it abundantly clear that the commission had concerns about “the nature and quality (of service) furnished by the utility.” The impact on the customers of a large percentage increase suddenly imposed was another example of an “other reason” [s. 65(4)(c)] to which the commission gave due regard in deciding to phase in the increase in three steps. The commission was not prepared to grant an immediate increase in the amount requested by the applicant, but granted instead a modest increase initially and set a target for an allowable rate of return which HVES could work towards, together with suggestions and commentary on how the company might improve its operation.

[35] The commission then turned to the question of “rate shock” and rejected the submission of HVES with respect to the three-year phase-in of the allowed rate increase. It stated its determination as follows:

The *Utilities Commission Act* places a duty upon the commission to balance all the factors which the Act includes as matters for due regard when fixing rates. HVES has emphasized one element, namely, return on the appraised value of the utility’s property in terms of typical costs of money in the financial markets. It refers, in reply to argument by HVES to “the absolute limitation imposed by s. 65(4)(b).” The commission does not accept that any such absolute limitation applies, but is of the view that counsel for HVES, at pp. 4 and 5 [There is an error in Karen Knott’s quote.] has correctly recognized the breadth of the commission’s mandate.

[36] The issue before us, simply stated, is: “was the commission right?”

## DISCUSSION

[37] Any discussion of the scope of the commission’s rate-making powers begins, of necessity, with the seminal decision of the Supreme Court of Canada in *British Columbia Electric Railway Co. v. British Columbia Public Utilities Commission*, supra. In that case the Supreme Court had before it a legislative scheme prescribed by the *Public Utilities Act*, R.S.B.C. 1948, c. 277 (the “old Act”) similar to (and here the appellant submits, identical to) the scheme found in the *Utilities Commission Act* (the “new Act”). It will, I think, be convenient to set out side by side the relevant provisions of the two statutes so that their similarities or differences may be readily apparent.

### **OLD ACT**

#### *Interpretation.*

2.(1) In this Act ...

“Unjust” and “unreasonable” as applied to rates shall be construed to include respectively injustice and unreasonableness, whether arising from the fact that rates are excessive as being more than a fair and reasonable charge for service of the nature and quality furnished by the public utility, or from the fact that rates are insufficient to yield fair compensation for the service rendered, or arising in any other manner:

16. (1) In fixing any rate

(a) The Commission shall consider all matters which it deems proper as affecting the rate.

(b) The Commission shall have due regard, among other things, to the protection of the public from rates that are excessive as being more than a fair and

### **NEW ACT**

#### **Discrimination in rates**

65. (1) A public utility shall not make, demand or receive an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service furnished by it in the Province, or a rate that otherwise contravenes this Act, regulations, orders of the commission or other law.

(2) A public utility shall not, as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description, and the commission may, by regulation, declare the circumstances and conditions that are substantially similar.

reasonable charge for services of the nature and quality furnished by the public utility; and to giving to the public utility a fair and reasonable return upon the appraised value of the property of the public utility used, or prudently and reasonably acquired, to enable the public utility to furnish the service.

(c) Where the public utility furnishes more than one class of service, the Commission shall segregate the various kinds of service into distinct classes or categories of service; and for the purpose of fixing the rate to be charged for the service rendered, each distinct class or category of service shall be considered as a self-contained unit, and the rates fixed for each unit shall be such as are considered just and reasonable for that unit without regard to the rates fixed for any other unit. If it is considered by the Lieutenant-Governor in Council that the rates as so determined might be inequitable or contrary to the general public interest, the Lieutenant-Governor in Council may direct that two or more classes or categories of service shall be considered as one unit in fixing the rate.

(3) It is a question of fact, of which the commission is the sole judge, whether a rate is unjust or unreasonable, or whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or whether a service is offered or furnished under substantially similar circumstances and conditions.

(4) In this section a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality furnished by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service rendered by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

#### **Rates**

66. (1) In fixing a rate under this Act or regulations

(a) the commission shall consider all matters that it considers proper and relevant affecting the rate,

(b) the commission shall have due regard, among other things, to the fixing of a rate that is not unjust or unreasonable, within the meaning of section 65, and

(c) where the public utility furnishes more than one class of service, the commission shall segregate the various kinds of service into distinct classes of service; and in fixing a rate to be charged for the particular service rendered, each distinct class of service shall be considered as a self contained

unit, and shall fix a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

[38] The facts giving rise to the *British Columbia Electric* case are succinctly set forth in the majority judgment of Martland J. (for himself and Cartwright and Ritchie JJ.) at pp. 850-51 of the report [S.C.R.]:

The appellant and British Columbia Electric Company Limited (together called “the Company”) are related companies and between them own and operate equipment and facilities for the transportation of persons and property by railway, trolley coach and motor buses and for the production, generation and furnishing of gas and electricity, all for the public for compensation.

The Company is regulated by the Public Utilities Commission of British Columbia (called “the Commission”) pursuant to the provisions of the *Public Utilities Act*.

By appraisal the Commission ascertained the value of the property of the Company used, or prudently and reasonably acquired, to enable the Company to furnish its services. The appraisal was made as of December 31, 1942, and since then has been kept up to date. The appraised value is referred to as “the rate base”.

By Order-in-Council No. 1627, approved on July 16, 1948, the Commission was directed to consider the classes or categories of the regulated services of the Company as one unit in fixing the rates.

On September 11, 1952, the Commission after public hearing made “Findings as to Rate of Return” and decided that, “until changed financial and market circumstances convince the Commission that a different rate should be applied, the Commission will in its continuing examination of the Company’s operations apply the rate of 6.5%” on the rate base as a fair and reasonable rate of return for the Company. This decision remains unchanged.

The Company from time to time amended its rate schedules with the consent of the Commission and filed with the Commission schedules showing the rates so established. On April 23, 1958, it applied for the consent of the Commission, under s. 17 of the *Public Utilities Act*, to file amended schedules containing increased rates for its electric service on the Mainland and on Vancouver Island. On July 28, 1958, it also applied for the consent of the Commission to file amended schedules containing increased transit fares for its transit systems in Vancouver and other Mainland areas and in Victoria and surrounding areas.

Public hearings were held by the Commission and it handed down its decision with respect to the electric applications on July 14, 1958, and with respect to the transit applications on October 30, 1958.

Briefly, the decisions of the Commission accepted the proposed rate schedules submitted by the Company, except that it refused to approve the proposed increases in the principal residential electric rates on the Mainland and on Vancouver Island. It directed that those rates be scaled down by approximately 25%. In its decision with respect to electric rates the Commission stated:

“The Commission has therefore consented to the filing to be effective July 15th, 1958, of all the rate schedules submitted by the Company for the Mainland and Vancouver Island, as modified and supplemented by the Company during the course

of the hearings on its application, except the residential rate schedules and Mainland Rate 3035 for industrial users.

“The Commission has decided that the principal residential rate on the Mainland (Schedule 1109) and the principal residential rate on the Island (Schedule 1110 under which the principal divisions are Billing Codes 1110 and 1112) should be adjusted to yield not more than three-quarters of the additional revenue proposed. The adjustment must be applied primarily to reduce sharp changes in impact and lessen disproportionately large percentage increases in the consumption range of 60 KWH to 280 KWH per month. Comparable adjustments must also be made in some of the related special residential rates of lesser importance. Most of the relief would be given to the small residential user.”

At the same time the Commission decided that further increases in the commercial and industrial rates to compensate for this reduction in the proposed residential rates would not be justified.

At p. 849 Martland J. had said:

Pursuant to the provisions of subs. (1) of s. 107 of the *Public Utilities Act* of British Columbia, R.S.B.C. 1948, c. 277, the Public Utilities Commission of that Province stated a case for the opinion of the Court of Appeal of British Columbia. Five questions were submitted for the consideration of the Court, of which the first was as follows:

“(1) (a) Was the Commission right in deciding as appears in the said Reasons for Decision of 14th July, 1958, that no one of the matters and things referred to in clauses (a) and (b) of subsection (1) of Section 16 of the ‘Public Utilities Act’ should as a matter of law be given priority over any other of those matters or things and that, if a conflict arises among these matters or things, it is the Commission’s duty to act to the best of its discretion?”

“(b) If the answer to question (1) (a) is ‘No’, what decision should the Commission have reached on the point?”

Question (1)(a) was answered in the affirmative. The appellant, by special leave of this Court, has appealed from that portion of the judgment of the Court of Appeal which comprises the answer given by it to question (1). The other four questions and the answers given to them are not in issue in this appeal.

[39] After summarizing the facts as I have set them out from the judgment of Martland J., his Lordship continued, at pp. 852-53:

In the reasons given for its decision the Commission deals with the effect of clauses (a) and (b) of s. 16(1) and says:

“With great respect, the Commission considers that although for this purpose the statutory duty of the Commission to have due regard to all matters which the Commission deems proper as affecting the rate might without any significant inaccuracy be described as the right of the Commission, and its statutory duty to *have due regard to giving* the utility a fair and reasonable return might without significant inaccuracy be described as the Commission’s *responsibility for giving* the utility a fair and reasonable return, there is nothing in the Act to relieve the Commission in the case now before it from complying with the language of the Act and giving due regard to all those matters to which the legislature has directed the Commission to give due regard in fixing a rate. No one of those matters should, in

the opinion of the Commission, be given as a matter of law priority over any other of those matters and if, as the legislature appears to have thought possible, a conflict arises among those matters, the Commission considers that it is its duty to act to the best of its discretion.”

The Court of Appeal concurred in this view. The judgment of the Court, delivered by Sheppard J.A., refers to this question in the following words:

“A further inquiry is what weight should be given to the matters required to be considered by Sec. 16(1)(b) and particularly to the ‘fair and reasonable return’... Although clauses (a) and (b) of Sec. 16(1) require certain matters to be considered, they do not state what weight is to be assigned by the Commission. Consequently, the Statute requires only that the Commission consider the matters falling within Sec. 16(1)(a), namely, ‘all matters which it deems proper as affecting the rate’ and those falling within Sec. 16(1)(b), namely, ‘the protection of the public’ and ‘a fair and reasonable return’ to the Utility. But the Statute does not require more, and does not require any weight to be given to these matters after they have been considered. Hence the weight to be assigned is outside any statutory requirement and must be a question of fact for the Commission in each instance.”

[40] At p. 854 he observed, “The necessity for giving a public utility fair compensation for the service which it renders appears in the definition of the words ‘unjust’ and ‘unreasonable’ in s. 2(1)” (quoted above).

[41] At pp. 855-57, Martland J. said:

Section 16, the section with which we are concerned in this appeal, also deals with this matter of fairness of rates. In addition, it spells out the method by which a public utility is to obtain fair compensation for its service; i.e., by a fair and reasonable return upon its rate base, which rate base, pursuant to s. 45, the Commission can determine by appraisal.

Section 16 deals with the duties of the Commission in fixing rates. Clause (a) of subs. (1) states that the Commission shall consider all matters which it deems proper as affecting the rate. It confers on the Commission a discretion to determine the matters which it deems proper for consideration and it requires the Commission to consider such matters.

Clause (b) of subs. (1) does not use the word “consider”, which is used in clause (a), but directs that the Commission “shall have due regard”, among other things, to two specific matters. These are:

(i) The protection of the public from rates that are excessive as being more than a fair and reasonable charge for services of the nature and quality furnished by the public utility; and

(ii) To giving to the public utility a fair and reasonable return upon the appraised value of its property used or prudently and reasonably acquired to enable the public utility to furnish the service.

As I read them, the combined effect of the two clauses is that the Commission, when dealing with a rate case, has unlimited discretion as to the matters which it may consider as affecting the rate, but that it must, when actually setting the rate, meet the two requirements specifically mentioned in clause (b). It would appear, reading ss.8, 16 and 20 together, that the Act contemplates these two matters to be of primary importance in the fixing of rates.

In my opinion, therefore, these two factors should be given priority over any other matters which the Commission may consider under clause (a), or any other things to which it shall have due regard under clause (b), when it is fixing any rate.

The second portion of question (1)(a) was as to whether, in case of conflict among the matters and things referred to in clauses (a) and (b) of s. 16(1), it was the Commission's duty to act to the best of its discretion. I have already expressed my view regarding the priority as between those things specifically mentioned in clause (b) and the other matters or things referred to in clauses (a) and (b). This leaves the question as to possible conflict as between the two matters specifically mentioned in clause (b).

Clearly, as between these two matters there is no priority directed by the Act, but there is a duty imposed upon the Commission to have due regard to both of them. The rate to be imposed shall be neither excessive for the service nor insufficient to provide a fair return on the rate base. There must be a balancing of interests. In my view, however, if a public utility is providing an adequate and efficient service (as it is required to do by s. 5 of the Act), without incurring unnecessary, unreasonable or excessive costs in so doing, I cannot see how a schedule of rates, which, overall, yields less revenue than would be required to provide that rate of return on its rate base which the Commission has determined to be fair and reasonable, can be considered, overall, as being excessive. It may be that within the schedule certain rates may operate unfairly, relatively, as between different classes of service or different classes of consumers. If so, the Commission has the duty to prevent such discrimination. But this can be accomplished by adjustments of the relative impact of the various rates in the schedule without having to reduce the total revenues which the whole schedule of rates is designed to produce.

He then answered the question posed as follows:

Accordingly, it is my opinion that the answer to question (1)(a) should be "No". My answer to question (1)(b) would be that the Commission, in priority to any other matters which it may deem proper to consider under clause (a) and any of the other things referred to in clause (b) of s. 16(1), should have due regard to the two matters specifically mentioned in clause (b). In the present case, having decided that certain of the rates proposed by the appellant would impose an unreasonable burden upon certain classes of consumers, the Commission should permit the Company to submit alternative schedules of rates, which, while yielding approximately the same overall revenues, would eliminate the comparatively excessive impact of those classes of rates to which the Commission objected, until a rate schedule is devised which meets the requirements of clause (b) of s. 16(1).

[42] Locke J. delivered a separate concurring judgment in which, as appears at p. 849 of the report, he agreed specifically with the answer to the second part of the question proposed by Martland J.

[43] Both Mr. Sanderson for the appellant and Mr. Foy for the respondent Attorney General of British Columbia relied heavily upon the decision in the *British Columbia Electric* case, each asserting that it supported their opposing points of view.

[44] Mr. Foy firstly drew attention to the passage in the judgment of Martland J. at pp. 855-56 where that learned judge focused on the fact that, in s. 16 of the old Act, cl. (b) of

subs. (1) does not use the word “consider,” which is used in cl. (a), but directs that the commission “shall have due regard,” among other things, to two specific matters. He then pointed to the fact that, by virtue of the wording and structure of ss. 66(1)(b) and 65(4), and particularly by s. 65(4)(c), of the new Act, a third matter, namely, that a rate may be “unjust and unreasonable for any other reason,” has been elevated to being not merely one of the matters which the commission “considers proper and relevant affecting the rate” (its mandate under s. 66(1)(a)), but to one of the now three (formerly only two) specific matters to which the commission is directed to “have due regard.” Mr. Foy then referred to the statement of Martland J. at p. 856 that “there must be a balancing of interests.” From this he argued that the commission, in directing the three-year phase-in of the rate adjustment to ameliorate the rate shock, was simply “balancing” the interests of HVES on the one hand and its customers on the other, and contended that, in so doing, it was correctly applying the law which prescribes its mandate. It was entitled to what it did, he said, because the commission had concerns about “the nature and quality of service furnished by the utility.”

[45] Mr. Foy argued that to accede to the position of HVES would be to accord to one of the specific matters to which the commission must have due regard (the matter referred to in s. 65(4)(b)) a priority over the other two, something which cannot be done.

[46] Mr. Sanderson submitted that once the commission had settled the content of the rate base and determined a rate of return which is both just and reasonable, it cannot fix a schedule of rates which yields less revenue than would be required to provide that rate of return on its rate base. In this respect he relied upon what Martland J. said at p. 856 (above). He also referred at length to the judgment of Locke J. and drew attention firstly to this passage at p. 841:

The real question might have been stated more clearly had it asked whether as a matter of law a duty rested upon the Commission to approve rates which would produce for the appellant a fair and reasonable return upon the appraised value of the property used or prudently and reasonably acquired by it to enable it to furnish the service described in the Act when the fact as to what constituted a fair return had previously been determined by the Commission. This is the matter to be determined.

[47] Locke J., in his reasons commencing at p. 841, reviewed the legislative history of the old Act and of its predecessor, the *Water Act Amendment Act*, S.B.C. 1929, c. 67, American regulatory jurisprudence, and the common law and said at p. 846:

In my opinion the true meaning of the relevant sections of the *Public Utilities Act* is that a utility is given a statutory right to the approval of rates which will afford to it fair

compensation for the services rendered and that the quantum of that compensation is to be a fair and reasonable rate of return upon the appraised value of the property of the company referred to in s. 16(1)(b).

[48] Locke J. continued at p. 847:

Rates that fail to yield fair compensation for the service rendered are declared by s. 2 to be unjust and unreasonable as they were by s. 2 of the *Water Act Amendment Act* of 1929. The Commission is directed by s. 16(1)(b) to have due regard to fixing a rate which will give to the utility a fair and reasonable return upon the appraised value of its property used or prudently and reasonably acquired to enable it to furnish the service. It is the inclusion of the expression “shall have due regard” which has led the Commission and the Court of Appeal to conclude that this means that allowing a fair return upon the appraised value is simply one of the matters to be considered by the Commission in fixing the rate. Clearly no such interpretation could have been placed upon this expression under the provisions of the *Water Act* in view of the express provisions of s. 141C, and with great respect I think no such interpretation should be given to it in the present statute,

And at pp. 847-48:

I can find nothing in this legislation indicating an intention on the part of the Legislature to empower the Commission to deprive the utility of its common law right to be paid fair compensation for the varying services rendered or to depart from the declared intention of the Legislature in the *Water Act Amendment Act* that such companies upon whom these obligations are imposed are entitled to have the quantum of such fair compensation determined as a fair return upon the appraised value of the properties required,

And finally, at p. 848:

The obligation to approve rates which will produce the fair return to which the utility has been found entitled is, in my opinion, absolute, which does not mean that the obligation of the Commission to have due regard to the protection of the public, as required by s. 16(1)(b), is not to be discharged. It is not a question of considering priorities between “the matters and things referred to in Clauses (a) and (b) of subsection (1) of s. 16”. The Commission is directed by s. 16(1)(a) to consider all matters which it deems proper as affecting the rate but that consideration is to be given in the light of the fact that the obligation to approve rates which will give a fair and reasonable return is absolute.

[49] Mr. Sanderson accepted that the commission is required to have due regard to what is referred to in s. 65(4)(c) but submitted that, in directing the three-year phase-in of the rate adjustment with no offsetting provision to permit HVES to obtain sufficient revenue to recover the shortfall, the commission has committed the very sin which Mr. Foy charges against the utility, namely, that instead of having due regard – and giving effect – to the three specific matters set out in s. 65(4), it has accorded priority to either s. 65(4)(a) or (c) and relegated s. 65(4)(b) to simply “a matter to be considered.”

[50] Mr. Sanderson contended that if the commission was properly concerned to ameliorate the rate shock of a sharp rise in rates to be charged it could do so but only if, at the same time, it directed the filing of rate schedules which, over a reasonable period of time, would provide sufficient revenues to enable the utility to catch up and recover the shortfall. HVES, he said, is entitled to be made whole by the standards, in terms of the rate base and allowable rate of return thereon, which the commission itself fixed. It is only in this way that the commission can properly discharge its mandate and comply with the direction to have due regard to all the matters referred to in s. 65(4) without according priority to one or another of them.

[51] The addition of s. 65(4)(c) in the Act, however, is not an *alternative* to s. 65(4)(a) and (b), but rather is an *additional* basis on which rates may be found to be unjust and unreasonable. Accordingly, while rates may be unjust or unreasonable for reasons other than those set out in s. 65(4)(a) and (b), it remains the law that if a rate is insufficient to yield a fair and reasonable return on rate base, it is necessarily “unjust and unreasonable” within the meaning of s. 65(4)(b).

[52] Mr. Sanderson’s submissions continued as follows:

[53] A distinction has been drawn in the case law between regulatory systems which afford the administrative tribunal an unfettered discretion to fix rates and those which provide the tribunal with specific statutory directions as to how these rates are to be fixed: see *British Columbia Hydro & Power Authority v. Westcoast Transmission Co.*, [1981] 2 F.C. 646, 36 N.R. 33 (C.A.).

[54] The current *Utilities Commission Act* is an example of the latter. Sections 65(4)(b) and 66(1)(b) amount to a statutory direction as to how the commission is to determine a just and reasonable rate. If, as posited by Martland J., a public utility is providing an adequate and efficient service, the statute is clear: a rate is unjust or unreasonable if it fails to yield a just and reasonable return on rate base. Here, while there may be room for improvement, the commission’s recommendations with respect to quality of service referred to above are calculated to achieve what is desired. Accordingly, the commission has no discretion to fix rates which do not permit recovery of that return.

[55] The virtually identical nature of the relevant provisions of the old Act and the new Act compel the conclusion that pursuant to the new Act, HVES is similarly given a statutory right to the approval of rates which will afford it the opportunity to earn a fair and

reasonable rate of return upon the appraised value of its property. Commission O. G-77-90 denies HVES that opportunity.

[56] In my view Mr. Sanderson's submissions are sound and must be accepted.

[57] The *Utilities Commission Act* empowers the commission to determine what is a fair and reasonable rate of return upon the appraised value of the property of regulated utilities, but, having done so, requires the commission to set rates so as to allow recovery of a rate which permits an opportunity to earn that return. In this case, the commission correctly exercised its discretion to determine what a just and reasonable return was, but wrongly failed to permit HVES to charge a rate which gave it an opportunity to earn that return. For this reason, it is my view that commission O. G-77-90 cannot stand, and that O. G-I 1-91 must fall with it.

[58] With respect to Mr. Foy's able and forceful submissions they are, in my view, flawed, and for these reasons.

[59] Firstly, in directing the three-year phase-in, the commission was not balancing interests or, if it was purporting to do, it acted improperly. The proper balancing of interests which the commission carried out was done and completed when it settled the rate base, fixed the rate of return and determined the costs of operation allowable for rate-making purposes. It must be remembered that the rate base itself was the subject of much contention at the public hearing and that only after the commission had considered alternative calculations for rate base did it decide to accept HVES' evidence in this regard. It must be remembered as well that HVES had proposed a rate of return of 13 per cent on the debt component and 15 per cent on the equity component of the rate base. The commission denied HVES' request and fixed 13 per cent as the just and reasonable rate of return on both components. In addition, as can be seen from sheet 5 of the Appendix to these reasons, the commission made substantial downward adjustments to many of HVES' estimates of its costs of operation.

[60] This is the balancing of interests which the commission carried out in performing its function. HVES has accepted the commission's decision in these respects. None are the subject of this appeal. Once this balancing of interests had been performed, it was the commission's duty to have due regard to the factors referred to in s. 65(4).

[61] Secondly, I cannot accept Mr. Foy's contention that the three-year phase-in was the result of the commission's expressed concern over the quality of service. The analysis I

have made of the original decision and of the reconsideration decision in my view refutes this contention. Alternatively, if in fact the commission decreed the three-year phase-in for this suggested reason it was wrong in law in doing so for it gave an unwarranted priority to one or another of the matters set out in s. 65(4) at the sacrifice of s. 65(4)(b).

[62] Thirdly, Mr. Foy submitted that “rate shock” is a recognized phenomenon which has attracted a number of rate moderation plans, including rate base phase-ins, in the utility regulation field, and he referred to the following authorities: Bonbright, Danielsen and Kamerschen, *Principles of Public Utility Rates* (1988), pp. 260-64; D. Scotto, “Post-Operational Phase-in of Utility Plant: Prolonging the Inevitable” (1983), 112 *Public Utilities Fortnightly*, September 1, pp. 28-34; I.M. Massella, “Rate Moderation Plans – Cushioning ‘Rate Shock’ “ (1984), 113 *Public Utilities Fortnightly*, February 16, pp. 52-56; *Re California-Pacific Utilities Co.*, 52 P.U.R. 3d 446 (1964); and *Re Pacific Telephone & Telegraph Co.*, 65 P.U.R. 3d 517 (1966).

[63] The underlying principle of this theory of gradualism in the implementation of new rate schedules is perhaps best explained in the article by Scotto, “Post-Operational Phase-in of Utility Plant: Prolonging the Inevitable.” There the author wrote at p. 28:

In 1982 two new terms were added to the electric utility industry’s lexicon: “rate shock” and “phase-in.” Rate shock refers to a sudden and “substantial” increase in electric rates. The concept can be illusive because the demarcation between “substantial” and “nonsubstantial” rate increases is usually a function of local political and economic sensitivities rather than a definitive, universal percentage increase. However, a 50 per cent jolt in rates would generally be considered substantial – well beyond the tolerance levels of most state commissions and ratepayers. Increases in the 20 per cent to 30 per cent vicinity, though, are more ambiguous. Rate shock is really a manifestation of the dollar disparity between rate base and new generating plant investment – the construction work in progress (CWIP) account. For a number of utilities the CWIP to net plant ratio can exceed 100 per cent, necessitating a high revenue increase – a rate shock – to reflect the plan in rate base upon commercial operation. As an alternative to the conventional one-shot hike in rates, new rate-making techniques have been proposed which are designed to spread the revenue impact of new plan investment into the postoperative years – hence, the term “phase-in”.

Post-operational phase-in can be accomplished in a variety of ways, most of which rely on accounting adjustments to protect the integrity of reported earnings. *The basic thesis in each case is the same: Capital recovery is spread over the asset’s useful life with no economic loss (at least in theory) to the utility*, (emphasis added)

[64] It can be seen that the purpose of “phase-in” is two-fold: to ameliorate the shock of suddenly imposed significant rate increases and, at the same time, to protect the integrity of the utility’s earnings. As the title to Mr. Scotto’s article itself indicates, it is merely “prolonging the inevitable.”

[65] The two regulatory decisions, *Re California-Pacific Utilities Co.*, decided in 1964, and *Re Pacific Telephone & Telegraph Co.*, decided in 1966, appear to be out of step with the main stream of American regulatory jurisprudence for, like the decision of the commission under consideration here, they did not provide for any catch up so that the utility could, over time, realize its authorized rate of return. I cannot regard them as binding or even persuasive.

[66] The power of the commission to phase in rates was perhaps presaged by Martland J. in the penultimate paragraph in his judgment in the *British Columbia Electric* case, where he said at p. 857:

... the Commission should permit the Company to submit alternative schedules of rates, which, while yielding approximately the same overall revenues, would eliminate the comparatively excessive impact of those classes of rates to which the Commission objected, *until a rate schedule is devised which meets the requirements of clause (b) of s. 16(1)*. (emphasis added)

[67] What the commission did here fails to meet the requirements of the legislation.

#### DISPOSITION

[68] In Pt. 4 of its factum, under the heading "Nature of Order Sought," the appellant seeks an order that:

- (a) the decision of the British Columbia Utilities Commission, dated January 30, 1991 be quashed;
- (b) that portion of the decision of the British Columbia Utilities Commission, dated October 17, 1990 requiring rates to be phased in and directing a refund be quashed;
- (c) the British Columbia Utilities Commission be directed to order HVES to file new tariff schedules permitting it to recover 13% on rate base from July 1, 1990;
- (d) monies held by Lawson, Lundell, Lawson & McIntosh pursuant to the order of Mr. Justice Toy of March 7, 1990 be paid to HVES;
- (e) costs; and
- (f) such further relief as to this Honourable Court may seem just.

[69] I think the proper course for this court to adopt is to allow this appeal and to refer the matter back to the commission with the direction that it permit, or require, HVES to file new tariff schedules which will enable it to earn 13 per cent on its determined rate base from July 1, 1990.

[70] If the commission considers it necessary or appropriate to ameliorate rate shock by directing the phasing in of such revised rates, it shall do so in a way which meets the requirements of s. 65(4) as set out in these reasons.

[71] It will be for the commission to make an order for the appropriate disposition of the funds referred to in para. (d) above.

[72] Section 118 of the Act exempts the commission from any liability for the costs of this appeal. I do not think it appropriate to order that the Attorney General, and thereby the general public, bear those costs. However, I note from para. 5.3 of the original decision and from sheet 3 of the Appendix that provision was made for the recovery, through the rates to be charged, of the sum of \$35,000 for HVES' rate application costs before the commission.

[73] Accordingly, I would direct that, failing agreement between the parties, HVES tax its costs for fees and disbursements of and incidental to this appeal and that the amount so determined be included in the rate application costs in the schedule.

*Order accordingly.*

HEMLOCK VALLEY ELECTRICAL SERVICES LTD.

UTILITY RATE BASE SCHEDULE 1		TEST YEAR APPLICATION	BCUC ADJUSTMENT	NO.	TEST YEAR ADJUSTED
ASSETS					
Structures and improvements		\$5,560			\$5,560
Overhead conductors and devices		44,891			44,891
UG Conductors and devices		479,504			479,504
Line transformers		90,693			90,693
PLANT IN SERVICE, opening		\$620,648	\$0		\$620,648
Additions to plant in service		0			0
Disposals		0			0
PLANT IN SERVICE, closing		620,648	0		620,648
Add: Work in progress		0			0
Less:		620,648	0		620,648
Accumulated Depreciation		(178,677)			(178,677)
NET PLANT IN SERVICE		441,971	0		441,971
WORKING CAPITAL ALLOWANCE		0			0
RATE HEARING COSTS		0			0
CONTRIBUTIONS IN AID		(75,460)			(75,460)
UTILITY RATE BASE		\$366,511	\$0		\$366,511
RETURN ON RATE BASE		14.01%	-1.01%		13.00%

HEMLOCK VALLEY ELECTRICAL SERVICES LTD.

UTILITY INCOME & RETURN SCHEDULE 2	TEST YEAR APPLICATION	BCUC ADJUSTMENT	NO.	TEST YEAR ADJUSTED
SALES VOLUME MWh	2,047			2,047
RATES				
Existing Revenue: ¢/kWh	8.65	0.00		8.65
Interim Increase %	42.77%	0.00%		42.77%
Final Increase %	84.62%			43.54%
First year phase-in: ¢/KWh		1.51		1.51
Second year phase-in: ¢/kWh		1.51		1.51
Third year phase-in: ¢/kWh		0.75		0.75
Final Rate: ¢/kWh	15.97	-3.55		12.42
Interim Rate	12.35			
REVENUE				
Existing Rates	\$177,066	\$0		\$177,066
Interim Rates	75,739			75,739
Required Increase	74,101	(72,740)		1,361
Discounts	0			0
Other Income	0			0
TOTAL REVENUE	326,906	(72,740)		254,166
Less: PURCHASED POWER	125,500	(15,371)	[1]	110,129
GROSS MARGIN	201,406	(57,369)		144,037
% excluding Other Income	61.61%	-4.94%		56.67%

Administration, Accounting and Office		68,300	(25,300)	[2]	43,000
UTILITY INCOME & RETURN SCHEDULE 2		TEST YEAR APPLICATION	BCUC ADJUSTMENT	NO.	TEST YEAR ADJUSTED
Repairs, Maintenance and Vehicle		31,000	(11,000)	[3]	20,000
Snow Removal		18,000	(18,000)	[4]	0
Depreciation		15,065			15,065
Amortization of Rate Application		10,000	1,667	[6]	11,667
OPERATING EXPENSES		142,365	(52,633)		89,732
Utility income before tax		59,041	(4,735)		54,306
INCOME TAX EXPENSE		7,693	(1,035)		6,658
EARNED RETURN		\$51,348	(\$3,700)		\$47,648
RETURN ON RATE BASE		14.01%	-1.01%		13.00%

HEMLOCK VALLEY ELECTRICAL SERVICES LTD.

INCOME TAXES SCHEDULE 3	TEST YEAR APPLICATION	BCUC ADJUSTMENT	NO.	TEST YEAR ADJUSTED
UTILITY INCOME BEFORE TAX	\$59,041	(\$4,735)		\$54,306
Deduct – Interest	(23,823)	0		(23,823)
ACCOUNTING INCOME	35,218	(4,735)		30,482
Timing differences Depreciation	15,065	0		15,065
Amort, of hearing costs	10,000	1,667	[6]	11,667
Amortization of Line Costs	0			0
Capital cost allowance	(15,065)			(15,065)
Amort, of contributions				0
Overhead capitalized				0
Plant removal costs				0
Rate application costs	(30,000)	(5,000)	[6]	(35,000)
	(20,000)	(3,333)		(23,333)
TAXABLE INCOME	\$15,218	(\$8,069)		\$7,149
Income tax rate – deferred	21.84%	0.00%		21.84%
Income tax rate – current	21.84%	0.00%		21.84%
Income tax expense				
– Deferred	\$4,369	\$728		\$5,097
– Current	3,324	(1,762)		1,561
INCOME TAX EXPENSE	\$7,693	(\$1,034)		\$6,658
	=====	=====		=====

HEMLOCK VALLEY ELECTRICAL SERVICES LTD.

RETURN ON CAPITAL SCHEDULE 4		TEST YEAR APPLICATION	BCUC ADJUSTMENT	NO.	TEST YEAR ADJUSTED
Contribution in Aid		\$0	\$0		\$0
proportion		.00%	0.00%		.00%
Capital Loan		\$0	\$0		\$0
proportion		.00%	0.00%		.00%
embedded cost		.00%	0.00%		.00%
\$ return		\$0	\$0		\$0
Current Debt		\$0	\$0		\$0
proportion		.00%	0.00%		.00%
embedded cost		.00%	0.00%		.00%
\$ return		\$0	\$0		\$0
Notional debt		\$183,256	\$0		\$183,256
proportion		50.00%	\$0		50.00%
embedded cost		13.00%	0.00%		13.00%
\$ return		\$23,823	\$0		\$23,823
Preferred shares		\$0	\$0		\$0
proportion		.00%	0.00%		.00%
embedded costs		.00%	0.00%		.00%
\$ return		\$0	\$0		\$0
Common equity		\$183,256	\$0		\$183,256
proportion		50.00%	0.00%		50.00%
ROE		15.02%	-2.02%	[5]	13.00%

\$ return		\$27,525	(\$3,700)	\$23,824
TOTAL CAPITAL		\$366,511	\$0	\$366,511

HEMLOCK VALLEY ELECTRICAL SERVICES LTD.

ADJUSTMENTS				
1. \$15,371	Adjust BC Hydro charges for error in Application			
2. \$25,300	Adjust Administration, Accounting and Office expenses to approved amount.			
3. \$11,00	Adjust Repair and Maintenance expenses to approved amount.			
4. \$18,000	Eliminate Snow Removal expenses.			
5. 2.02%	Adjust return on equity to 13%			
6. \$5,000	Adjust Rate Hearing costs.			
	Rate Increase Phase-in consists of:	Application	Final	First Year
	Purchased Hydro	6.13	5.38	5.38
	Operating expenses	6.22	3.65	3.65
	Rate Base costs	3.62	3.39	1.13
		-----	-----	-----
	Total	15.97	12.42	10.16
			% Increase	17.42