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FARRIS

January 27, 2026

BY ELECTRONIC FILING

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC Canada
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Attention: Registrar

Dear Sir/Madam:

Re: Application for Reconsideration and Variance of Order G-284-25 on Pacific Northern Gas (N.E.) Ltd.'s 2025 to 2027 Revenue Requirements and Stay of Proceeding

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

Pursuant to section 99 of the *Utilities Commission Act*, please find enclosed for filing the application (the **Reconsideration Application**) of PNG(NE) for reconsideration and variance of British Columbia Utilities Commission (**BCUC**) Order G-284-25, dated December 4, 2025, on PNG(NE)'s 2025 to 2027 Revenue Requirements. PNG(NE) also seeks a stay of proceeding.

Yours truly,

FARRIS LLP

Per:



Erica C. Miller

ECM/
Enclosures
c.c.: Client

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BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

the *Utilities Commission Act*, RSBC 1996 c 473

and

Pacific Northern Gas (N.E.) Ltd. Application for Reconsideration and Variance
of British Columbia Utilities Commission Order G-284-25
on the Pacific Northern Gas (N.E.) Ltd. 2025 to 2027 Revenue Requirements for the
Fort St. John/Dawson Creek and Tumbler Ridge divisions
and Stay of Proceedings

PACIFIC NORTHERN GAS (N.E.) LTD.

RECONSIDERATION APPLICATION & STAY OF PROCEEDINGS

January 27, 2026

Pacific Northern Gas (N.E.) Ltd.

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INTRODUCTION

1. Pacific Northern Gas (N.E.) Ltd. (**PNG(NE)** 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-284-25, dated December 4, 2025 (the **Decision**), regarding PNG(NE)'s 2025 to 2027 Revenue Requirements Application (the **Underlying Application**) for its Fort St. John/Dawson Creek (**FSJ/DC**) and Tumbler Ridge divisions. Additionally, PNG(NE) seeks a stay of the Commission's 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. More specifically, PNG(NE) seeks reconsideration of the Panel's direction that PNG(NE) reduce the capital expenditures for its Integrity Dig Campaign (the **Integrity Dig Expenditures**) in each of 2026 and 2027 by 50 percent for each of the FSJ/DC and Tumbler Ridge divisions.¹
3. PNG(NE) submits that the Panel erred in fact and/or law in concluding that PNG(NE) had not demonstrated a need for the full amount of its forecast Integrity Dig Expenditures for 2026/2027, and by finding that a 50 percent reduction in forecast Integrity Dig Expenditures for each of these years is appropriate and will enable PNG(NE) to address the priorities of its Integrity Dig Campaign while maintaining safe and reliable service.² In doing this, the Panel has set rates that are unjust or unreasonable.
4. In the Underlying Application, PNG(NE) put forward Integrity Dig Expenditures that incorporated the activities necessary to meet its obligation to provide safe and reliable service, and to remain compliant with applicable codes, standards and regulations, with respect to its high-pressure transmission lines. While the evidence is that PNG(NE) has some limited discretion to adjust the scope and timing of the specific activities performed as part of its Integrity Dig Campaign, there is no spending that can be deferred or avoided without severely diminishing PNG(NE)'s ability to manage pipeline integrity as a reasonable operator, and materially increasing PNG(NE)'s safety, reliability, operating and compliance risk.
5. If PNG(NE) must reduce its overall Integrity Dig Expenditures for 2026/2027 by 50 percent, as found by the Decision, this would prevent PNG(NE) from undertaking the necessary integrity activities to allow it to be compliant with its Integrity Management Program, as well as applicable codes, standards and regulations. The activities performed under the Integrity Management Program seek to prevent pipeline failure events and to extend the useful life of PNG(NE)'s assets, both of which are necessary for PNG(NE) to undertake as a prudent operator. Further, if PNG(NE) were compelled to undertake its Integrity Management Program in this reduced manner, it would be threatening its reputation with the British Columbia Energy Regulatory (**BCER**), which regulates PNG(NE)'s program. While PNG(NE)'s system is not subject to a BCER General Order (as is the case for the western division, Pacific Northern Gas Ltd. (**PNG-West**)), PNG(NE) must still carry out necessary integrity work, consistent with industry standards, or face increased regulatory scrutiny and oversight. Failing to do so would expose PNG(NE) to heightened risk of intervention or

¹ Decision, p. 16.

² Decision, p. 16.

enforcement orders from the BCER and may impact its ability to provide safe and reliable service to its customers.

6. In the alternative, if PNG(NE) 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(NE)'s Licence to Operate under the *Energy Resource Activities Act*), it forecasts that this will cost the full amount of the Integrity Dig Expenditures that PNG(NE) sought to recover in the Underlying Application for each of 2026 and 2027. That is, \$949,000 and \$978,000 for FSJ/DC and \$475,000 and \$490,000 for Tumbler Ridge.³ If PNG(NE) is denied recovery of 50 percent of these Integrity Dig Expenditure, as ordered by the Decision, its rates will be unjust and/or unreasonable, as 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.⁴
7. As a result, and as is set out in more detail below, the Panel's decision to deny recovery of 50 percent of PNG(NE)'s (relatively modest) Integrity Dig Expenditures for 2026/2027 will have a material impact on PNG(NE)'s customers, the Company, and its system.
8. As a result, in this Reconsideration Application, PNG(NE) seeks to vary the Decision that PNG(NE) be directed to reduce Integrity Dig Expenditures in each of 2026 and 2027 by 50 percent for each of the FSJ/DC and Tumbler Ridge divisions,⁵ so that the Decision instead provides that PNG(NE) may recover in rates the full amounts forecast in the Underlying Application for the Integrity Dig Expenditures for each of 2025, 2026 and 2027 (i.e., for the full **Test Period**).
9. PNG(NE) does not seek reconsideration or variation of Order G-284-25 in any other respect.
10. Further, in this Reconsideration Application, PNG(NE) seeks a stay of the operation of the Decision, pending the outcome of this reconsideration. Specifically, in the Decision, PNG(NE) 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.⁶ The content of this compliance filing will incorporate the amount of Integrity Dig Expenditures, and will therefore be 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(NE), 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(NE) had not filed a stay request by that date.
11. As is returned to below, PNG(NE) seeks a stay of the requirement to file its compliance filing, pending the determination of the Reconsideration Application, until three weeks following the BCUC's decision. PNG(NE) observes that, due to interdependencies in the financial modelling for PNG(NE) and the PNG-West revenue requirements (i.e. transfers to capital, shared service cost recoveries), the compliance filings for both utilities must be prepared concurrently. As a result, PNG(NE) seeks a stay of the requirement to file the compliance filings until three weeks following the latter of the BCUC's decisions on the PNG(NE) and the PNG-West reconsideration applications.

³ See Summary in Decision, p. 15, Table 10.

⁴ UCA, s. 59.

⁵ Decision, p. 16.

⁶ Decision, Order #9.

12. With respect to process, PNG(NE) submits that there is sufficient evidence on the record in the underlying proceeding (and now supplemented by the new evidence of the BCER with respect to PNG-West, 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(NE) submits that this application ought to proceed to a written hearing process. We set out below a proposed regulatory process for the BCUC's consideration.
13. Finally, PNG(NE) 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(NE) 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.⁷ The BCUC issued the Decision (Order and Decision G-284-25), on December 4, 2025. As is set out in more detail below, in this Reconsideration Application, PNG(NE) seeks reconsideration and variance of the Decision with respect to the integrity management capital expenditures.
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 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,⁸ 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.⁹ PNG(NE) 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.¹⁰

⁷ Ex. B-1, Underlying Application, p. 1.

⁸ BCUC Rules, Rule 31.02.

⁹ BCUC Rules, Rule 31.04.

¹⁰ BCUC Rules, Rule 31.05.

18. As is set out in more detail below, in this Reconsideration Application, PNG(NE) 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,¹¹ and the Commission will determine the regulatory process for the reconsideration hearing.¹²
20. PNG(NE) 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(NE) sets out a proposed regulatory process, for the BCUC’s consideration.

THE DECISION ON WHICH RECONSIDERATION IS SOUGHT: INTEGRITY DIG EXPENDITURES

21. PNG(NE) seeks reconsideration of the decision of the Panel to direct PNG(NE) that it reduce its Integrity Dig Expenditures for 2026/2027 by 50 percent, for each of the FSJ/DC and Tumbler Ridge regions.¹³ This is discussed below, including the grounds for reconsideration, the material impact of this aspect of the Decision, and the remedy sought by PNG(NE).
22. In the Underlying Application, PNG(NE) sought approval of the following Integrity Dig Expenditures for the FSJ/DC and Tumbler Ridge Divisions over the Test Period:¹⁴

Table 10: Test Period Integrity Digs Campaign Expenditures for FSJ/DC and Tumbler Ridge Divisions⁵⁹

Test Year	Forecast Integrity Digs Campaign Expenditures \$'000s	
	FSJ/DC	Tumbler Ridge
2025	\$484	\$250
2026	\$949	\$475
2027	\$978	\$490

¹¹ BCUC Rules, Rule 34.01.

¹² BCUC Rules, Rule 34.04.

¹³ Decision, p. 16.

¹⁴ Decision, p. 14; Ex. B-1, Underlying Application, FSJ/DC division, pp. 78, 90, 99; Ex. B-1, Underlying Application, TR division, pp. 74, 76, 79.

23. PNG(NE)'s Integrity Dig Campaign is a comprehensive, multi-year capital program.¹⁵ Under the campaign, specific physical excavations (or digs) are carried out on PNG(NE)'s pipeline, to address defects and anomalies identified through indirect inspections and engineering assessments, in order to maintain the integrity of PNG(NE)'s transmission system. The campaign is carried out by PNG(NE) to ensure pipeline and public safety, reliable gas supply for its customers, and that the pipeline remains compliant with applicable codes, standards and regulations.¹⁶
24. PNG(NE)'s Integrity Dig Campaign follows its Integrity Management Program, in accordance with the Association for Materials Protection and Performance (**AMPP**) standards for External Corrosion Direct Assessment (**ECDA**), to develop both multi-year forecasts and annual dig plans.¹⁷ The AMPP and ECDA are the methodology applicable to transmission lines that are not "piggable" such that they can be inspected by tools easily. It is informed by the results of year-over-year assessments, historical direct assessment data (arising from dig results, repairs, etc.) and engineering evaluations.¹⁸
25. Given that the PNG(NE) transmission system consists of no piggable pipelines, the execution of integrity digs is essential to understanding the condition of the system., PNG(NE)'s integrity program is not as mature as the program for the western system: PNG(NE) is in the early stages of collecting information about its transmission pipelines to build out a more mature, evidence-based integrity program. PNG(NE) conducts indirect inspections to identify areas where defects may exist such that it can drive its direct assessment plans. If the defects do exist, they can be fixed at that time. For example, in 2025, PNG(NE)'s Integrity Dig Expenditures identified and allowed for the repair of crack defects among other repairs, which if left undetected, could have impacted PNG(NE)'s ability to provide safe and reliable service. Additionally, each dig undertaken provides important information as to the condition of the overall pipeline that will contribute to maturing PNG(NE)'s integrity program.
26. As a prudent pipeline operator, PNG(NE) must carry out pipeline integrity work to ensure it can meet code requirements, including as regulated by the BCER. PNG(NE)'s Integrity Dig Expenditures support compliance with these code and regulatory requirements.¹⁹ Each planned integrity dig has the primary purpose of ensuring the safety of the operating asset as well as extending the safe and useful life of the pipeline assets and enabling PNG(NE) to assess the condition of PNG(NE)'s transmission pipelines in support of determining the required ongoing asset integrity activities needed to fulfill its operational and Integrity Management Program (i.e., compliance) requirements.. The indirect inspection methods used (which are used in determining the integrity digs to be completed), are compliant to the CSA Z662 code and aligned with AMPP ECDA standards. This process represents industry-accepted practices for assessing pipeline integrity.²⁰
27. PNG(NE) conducts an average of three indirect inspections per year. Based on the current trends from these indirect inspections, it forecasts an average of six integrity digs being carried out in each year of the Test Period, for each of the FSJ/DC division and the Tumbler

¹⁵ Decision, p. 15; Ex. B-1, FSJ/DC division, pp. 83, 94, 103; Ex. B-1, TR division, pp. 73, 76, 79.

¹⁶ Ex. B-1, Underlying Application, FSJ/DC division, pp. 83, 94, 103; Ex. B-1, Underlying Application, TR division, pp. 74, 76, 79.

¹⁷ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.1.1.

¹⁸ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.1.1.

¹⁹ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2.

²⁰ Ex. B-8, PNG(NE) Response to BCUC IR 1, IR 10.5.

Ridge division.²¹ However, the specific digs completed are subject to change as final dig plans are developed ahead of construction season each year, taking into account and adjusting for indirect assessment data, direct assessment results and engineering evaluations.²²

28. In the Decision, the Panel found that PNG(NE) had not demonstrated the need for the forecast level of Integrity Dig Expenditures for 2026/2027. In concluding this, it indicated that the forecast Integrity Dig Expenditures for these years were significantly higher than for 2025 and historical spending levels, and that PNG(NE)'s pipelines had not had any leaks in the last nine years and that the system was considered to be in "acceptable condition". While the Panel acknowledged that the BCER's expectations with respect to integrity management had increased in recent years, it found that PNG(NE) had not demonstrated that there was a condition-based need to increase integrity-related capital expenditures to the amounts requested in 2026/2027.²³ As a result, the Panel directed PNG(NE) to reduce its Integrity Dig Expenditures in 2026/2027 by 50 percent for each of FSJ/DC and Tumbler Ridge divisions.²⁴

A. The Grounds for Reconsideration

29. PNG(NE) submits that the BCUC made an error in fact or law, which had a material bearing on the Decision, in directing PNG(NE) to reduce its Integrity Dig Expenditures in 2026/2027 by 50 percent.

The Panel Erred in Finding that PNG(NE) Failed to Demonstrate Need

30. As noted above, in directing PNG(NE) to reduce its Integrity Dig Expenditures in 2026/2027 by 50 percent, the Panel found that PNG(NE) had not demonstrated the need for the forecast level of Integrity Dig Expenditures for 2026/2027.²⁵ With this in mind, the Panel found that a 50 percent reduction was appropriate for 2026/2027, and would enable PNG(NE) to address the priorities of its Integrity Dig Campaign, while maintaining safe and reliable service.²⁶ PNG(NE) submits it was an error for the BCUC to conclude that PNG(NE) had not demonstrated the need for its integrity management spending and that PNG(NE) could further prioritize the Integrity Dig Campaign, while maintaining safe and reliable service.
31. In developing its Integrity Dig Campaign and putting forward the Integrity Dig Expenditures sought in the Underlying Application, PNG(NE) focused on prioritizing only necessary integrity spending (including, in light of the rate increases sought in the Underlying Application). As a result, the (relatively modest) amount forecast for Integrity Dig Expenditures captures only the spending that is necessary to meet the threshold for acceptable system sustainment by industry and engineering standards.
32. The Integrity Dig Program proposed in the Underlying Application was developed to ensure compliance with PNG(NE)'s Integrity Management Program as well as applicable codes and standards, and to enable safe and reliable service to its customers, while being strongly

²¹ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.1.1.

²² Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.1.

²³ Decision, p. 16.

²⁴ Decision, p. 16.

²⁵ Decision, p. 16.

²⁶ Decision, p. 16.

driven by the cost pressures faced by PNG(NE).²⁷ As a result, none of the spending proposed by PNG(NE) as part of the Integrity Dig Expenditures can be deferred or avoided, without severely diminishing PNG(NE)'s ability to manage pipeline integrity as a reasonable operator, meet the expectations of the BCER, and adhere to the CSA Z662:23 standard.

33. While the Decision notes that PNG(NE) has some “limited discretion” to adjust the scope or timing of its Integrity Dig Campaign,²⁸ this is a reference to PNG(NE)'s having a limited ability to determine precisely what activities are to be completed and when (which is adjusted to respond to new information about pipeline condition, as it is learnt). In this respect, in a response to Information Requests (IRs) posed by the Commission, PNG(NE) explained that this “limited discretion” was to allow it to ensure that it was meeting the BCER's expectations and the AMPP standards²⁹ (i.e. to consider assessment data and engineering evaluations, and adjust the scope and timing of the plan to ensure they are taken into account). PNG(NE) further explained that the Integrity Dig Campaign involved “complex technical-integrity, scheduling, resource planning and compliance related factors”, which made substantial, or even moderate, changes to the plan very difficult.³⁰ This response was not intended to suggest that PNG(NE) had discretion (limited or otherwise) to avoid the forecast spending (which, already captured only the spending necessary to meet the threshold for acceptable system sustainment by industry and engineering standards), but rather the scope and timing of the plan. Ultimately, PNG(NE) has limited discretion to adjust the scope of its integrity activities; however, this is within the bounds of the budget it has determined is necessary to meet its minimum integrity requirements for these assets.
34. Further and in any event, even if certain spending could be prioritized, deferring other spending from 2026/2027 to beyond the Test Period (which would be problematic for the reasons set out above), this would merely delay and compound the activities required 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. Further, deferral of non-discretionary integrity work can ultimately result in irreversible degradation of the pipeline asset, to the point that safety is compromised and expensive replacement, rather than routine and less expensive repair, becomes necessary.
35. We note that the evidence put forward by PNG(NE) in the underlying proceeding included the following with respect to the necessity of the work forecast, the consideration of minimizing expenditures and PNG(NE)'s lack of discretion with respect to Integrity Dig Expenditures:
 - (a) PNG(NE) confirmed in the Underlying Application that:
 - (i) the forecast capital expenditures were “necessary in light of the age of the PNG(NE) system” and that it would “continue to look to only invest in the capital needed to safely and reliably provide gas service to PNG(NE)'s customers”;³¹

²⁷ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.8.

²⁸ Decision, p. 15; Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2.2.

²⁹ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2.2.

³⁰ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2.2.

³¹ Ex. B-1, Underlying Application, FSJ/DC division, p. 150 (emphasis added).

- (ii) in putting forward its capital spending, it “undertook a rigorous and risk reflective review of its capital expenditures to ensure its requests in this Application were limited to only those investments that are needed”;³²
 - (iii) it “limited its capital investments to those needed to safely and reliably serve customers today”;³³
 - (iv) it is “not making proactive investments for the purpose of serving prospective future new customers”;³⁴ and
 - (v) it “strives to not undertake capital work before it is needed such that even if the work can be pushed out one year, this is done to delay rate impacts arising from the assets coming into service”.³⁵
- (b) When asked by the BCUC about its ability to adjust the scope or timing of the dig campaign, PNG(NE) confirmed, as set out above, 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,³⁶ and
- (c) Likewise, when asked how many digs could be safely omitted, PNG(NE) again confirmed:

... PNG(NE) has limited discretion to adjust the scope or timing of its dig campaign and reduce dig forecasts with the data available at time of writing. PNG(NE) may alter its dig forecast for future applications once the integrity condition of its northeast high-pressure assets is better understood.³⁷

36. Insofar as the BCUC found that PNG(NE) had not demonstrated that there was a “condition-based need” for the increased Integrity Dig Expenditures,³⁸ PNG(NE) points to its aging infrastructure and, again, to the fact that the BCER oversees PNG(NE)’s Integrity Management Program and that PNG(NE) is executing its integrity work pursuant to this program, as is returned to below. Direct assessments (i.e. integrity digs) are required in order to demonstrate a “condition-based” need for unpiggable pipelines (via the AMPP ECDA methodology). In contrast, indirect inspections do not demonstrate this condition-based need on their own, so digs are required to look for and advance understanding of “conditions” on unpiggable pipelines. Ultimately, if PNG(NE) stop performing digs, it will stop finding “condition-based” needs.
37. PNG(NE) respectfully submits that it provided sufficient evidence in the proceeding to demonstrate the need for the full amount of Integrity Dig Expenditures sought, 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.

³² Ex. B-1, Underlying Application, FSJ/DC division, p. 149 (emphasis added).

³³ Ex. B-1, Underlying Application, FSJ/DC division, p. 149 (emphasis added).

³⁴ Ex. B-1, Underlying Application, FSJ/DC division, p. 149 (emphasis added).

³⁵ Ex. B-1, Underlying Application, FSJ/DC division, p. 149 (emphasis added).

³⁶ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2.2.

³⁷ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.3.1.

³⁸ Decision, p. 16.

The Panel Erred in Pointing to PNG(NE)'s Past (Lower) Capital Expenditures

38. As noted above, in finding that PNG(NE) be directed to reduce its Integrity Dig Expenditures in 2026/2027 by 50 percent, the Panel highlighted that the forecast Integrity Dig Expenditures for 2026/2027 were significantly higher than for 2025 and than historic spending levels.³⁹ Respectfully, it is an error for the Panel to suggest that historic spending is indicative of the spending that is reasonable and necessary for 2026/2027.
39. In response to IRs, when asked to discuss the factors that had led to PNG(NE) increasing its Integrity Dig Expenditures for the Test Period, PNG(NE) explained that its increased focus and spending on integrity work in the northeast was “reflective of the heightened regulatory expectations that PNG(NE) must meet”, and “consistent with industry practice”. In order to better evaluate the overall integrity of the pipeline, PNG(NE) has expanded the scope of its direct assessments. This approach is in line with standards and the expectations of the BCER and public. It also is now positioned with better tools and system information, enabling PNG(NE) to undertake a more detailed integrity analysis.⁴⁰ Ultimately, this further information, coupled with heightened regulatory obligations, has led PNG(NE) to the conclusion that an increased level of Integrity Dig Expenditures is necessary for system sustainment by industry standards.
40. While PNG(NE) noted in its IR responses that it was committed to “proactively increasing its understanding of each pipeline’s condition”,⁴¹ this reflects that PNG(NE) is seeking to understand the pipelines’ condition upfront (before a failure, and in order to prevent an incident from occurring), as opposed to implying that it is undertaking discretionary or non-essential activities. PNG(NE) must undertake activities to better understand the condition of its pipeline through its indirect assessments, engineering assessments and ultimately direct assessments through digging to ensure it is able to provide safe and reliable service. By proactively increasing its understanding of the condition of its pipelines, it is able to more efficiently plan its integrity activities by relying less on conservative planning assumptions that must be used when data is not known or measured. Absent these efforts being undertaken, PNG(NE)’s transmission pipelines may degrade to a point that replacement, and not the more inexpensive repairs, must be undertaken.
41. As PNG(NE) emphasized in its Final Argument, the integrity condition of the northeast pipeline system is not as well understood as for the PNG-West system because the program is less mature.⁴² This has led to increasing expenditures to obtain a better understanding of the system.
42. There is no evidence on the record in the underlying proceeding to suggest that an increase from past spending means that the Integrity Dig Expenditures are not necessary, and it was an error for the Panel to reach this conclusion.
43. The Panel erred in concluding that historic spending is indicative of the spending that will be reasonable and necessary for 2026/2027.

³⁹ Decision, p. 16.

⁴⁰ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.3.

⁴¹ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.3.

⁴² PNG(NE) Final Argument, para. 88.

The Panel Erred in Pointing to PNG(NE)'s Acceptable System Condition

44. Further, as noted above, in finding that PNG(NE) be directed to reduce its Integrity Dig Expenditures in 2026/2027 by 50 percent, the Panel emphasized that PNG(NE)'s pipelines had not had any leaks in the last nine years and that the system was considered to be in "acceptable condition".⁴³ This seems to suggest that, because PNG(NE)'s transmission pipelines have not had a leak in nine years, that they will continue to not leak or that ongoing work is not necessary to maintain current conditions. PNG(NE) respectfully submits that this is not correct and the BCUC was in error in reaching this conclusion and had no basis or evidence in front of it to make this finding.
45. In describing the integrity of the system as in "acceptable condition", and as having experienced no leaks in at least the last nine years, PNG(NE) continued to explain why the work was, in any event, necessary:

However, consistent with industry practice, PNG(NE) is now expanding the scope of direct assessments to better evaluate overall pipeline integrity condition to allow a more empirical asset condition in line with standards and expectations from the regulator and public.

The increased focus and spending on integrity across the northeast region is reflective of the heightened regulatory expectations that PNG(NE) must meet. As well, as it being positioned with better tools and system information to undertake more detailed integrity analysis. This approach is reflective of PNG(NE)'s continued commitment to safety, reliability, and compliance. PNG(NE)'s objective has been and will continue to be, to proactively increase its understanding of each pipeline's integrity condition in advance of any potential release events, and perform any necessary repairs as required.⁴⁴

46. There is an ongoing obligation for PNG(NE) to carry out integrity work, which is guided by the inspections/assessments completed. Historic leaks are not a metric that is used by PNG(NE) (or to its knowledge, other operators) as a primary input into Integrity Management Plans and expenditures. Industry practice, code requirements and direction from the BCER require proactive and preventative measures to maintain pipeline integrity, to prevent leaks and other modes of failure. The fact that PNG(NE)'s transmission pipelines have not had a leak in nine years or is "acceptable" has not eliminated the need for further and ongoing activities and does not mean that there will not be future problems without these activities. This is especially the case given PNG(NE)'s aging infrastructure.
47. It remains critical that PNG(NE) 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.⁴⁵ This continues regardless of past amounts spent or the lack of leaks in recent years (and, even if amounts could be deferred now the deferred work would simply compound in future periods).

⁴³ Decision, p. 16.

⁴⁴ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.3

⁴⁵ PNG(NE) Final Argument, para. 78; Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.3

48. There is no evidence on the record in the underlying proceeding to suggest that lack of a leak for this period means that necessary integrity work should not be performed, and it was an error for the Panel to reach this conclusion. PNG(NE) should not be compelled to operate its pipeline to a state of failure in order to justify its integrity spending. PNG(NE) should instead be enabled to invest in its system to ensure it can provide safe and reliable service to its customers, to protect the safety of the public, and to ensure it is in compliance with its Integrity Management Program and all codes, standards and regulations as required by BCER, the technical regulator for PNG(NE)'s pipelines.

The BCER

49. In the Decision, the Panel also relied upon that PNG(NE) had not been directed or ordered to complete any of the planned activities by the BCER.⁴⁶ While the Panel acknowledged that the BCER's expectations with respect to integrity management had increased in recent years, it found that PNG(NE) had not demonstrated that there was a condition-based need to increase integrity-related capital expenditures to the amounts requested in 2026/2027.⁴⁷
50. While it is correct that PNG(NE) has not been mandated by the BCER to carry out specific activities, this finding does not factor in that PNG(NE) has an obligation to undertake prudent integrity work to comply with code requirements regulated by the BCER, and was an error.
51. As PNG(NE) submitted in evidence in the proceeding (in response to BCUC IR 10.2):

The BCER has not directed or ordered any direct assessment or study scope related to the 2025-2027 PNG(NE) Transmission Mainline Integrity Dig Campaign; however, as a prudent operator, PNG(NE) must carry out pipeline integrity work to ensure it can meet code requirements regulated by the BCER.

[...]

In the absence of performing any required related activities to maintain the existing operating pressure, PNG(NE) may need to temporarily impose pressure restrictions to meet asset integrity requirements. The BCER may also impose pressure reductions with a restrictive order. In that case, PNG(NE) would be unable to meet its existing load requirements.⁴⁸

52. It is not the role of the BCER to direct PNG(NE) to perform specific integrity work. Pursuant to the *Pipeline Regulation*, which was enacted under the *Energy Resource Activities Act*, PNG(NE) is required to have a pipeline integrity management program that complies with certain minimum codes, as a condition to operate.⁴⁹
53. This program is overseen by the BCER, which ensures that the program is satisfactory, and that PNG(NE) is executing its integrity work pursuant to the program. The program is a condition of PNG(NE)'s Licence to Operate under the *Pipeline Regulation* and, as such, failing to implement the program puts PNG(NE)'s licence at risk. The BCER monitors outcomes and does not have the regulatory latitude to specify the activities to be

⁴⁶ Decision, p. 15.

⁴⁷ Decision, p. 16.

⁴⁸ Ex. B-8, PNG(NE) Response to BCUC IR No. 1, IR 10.2 (emphasis added).

⁴⁹ *Pipeline Regulation*, BC Reg 210/2010, s. 7.

undertaken; this latitude rests with PNG's accountable professional engineer, who applies their professional judgment to determine integrity activities and the associated budget to perform them. Likewise, it is an error for the BCUC to be seen to be making such technically complex decisions regarding PNG(NE)'s management and operations.

54. Since the issuance of the Decision, as well as the BCUC's decision with respect to PNG-West's revenue requirements application, the BCER has notified PNG-West and PNG(NE) (together, **PNG**) that it is aware that funding for future integrity activities has been limited as a result of these decisions, such that certain inspection and repair activities planned for the Test Period will not be completed. PNG(NE) and PNG-West each understand the BCER to be very concerned by this.
55. 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(NE)'s position that the full amount of the forecast integrity spending ought to be approved, particularly in the face of increased scrutiny from the BCER.
56. While the email focuses on PNG-West, likely as a result of the BCER General Order presently in effect with respect to certain segments of PNG-West's pipeline, the same principles apply equally to PNG(NE) and the necessary integrity work.
57. It was an error for the BCUC to conclude that, because the BCER has not directed specific work, that PNG(NE) does not need to maintain its current operating pressures by carrying out the forecast integrity expenditures.

The 50 Percent Reduction is Arbitrary

58. Finally, PNG(NE) 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 fairness as PNG(NE) was not given an opportunity to comment on the impact of this level of reduction.
59. As noted above under the heading "The Panel Erred in Finding that PNG(NE) Failed to Demonstrate Need", PNG(NE) is unable to defer or reduce the Integrity Dig Expenditures it sought for 2026/2027. PNG(NE) does not have the ability to prioritize expenditures within a budget that has been reduced by 50 percent, while maintaining safe and reliable service nor is there any evidence in the proceeding to suggest otherwise. Importantly, PNG(NE) was not asked to comment on the impact of a 50 percent reduction before it was ordered.
60. Further, the BCUC has no basis to assess how much investment is needed for safe and reliable service. PNG(NE) has put forward (relatively modest) spending, intended to allow the Company to start to build out its understanding of the condition of the pipeline and to fix defects as it proceeds – however, it cannot determine that a portion of this investment is not needed at this point in time, particularly as the current program is not yet that mature.
61. We note that in the Final Argument of BCOAPO-RCIA, they observed that there was "insufficient evidence to recommend an appropriate quantum of reduction", with respect to the Integrity Dig Expenditures.⁵⁰

⁵⁰ BCOAPO-RCIA Final Argument, p. 26.

62. As the planned program had already been designed around ensuring PNG(NE) undertakes only the work necessary (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(NE)'s Integrity Dig Expenditures for 2026/2027, while leaving it with the "discretion" to prioritize the work needed to safely continue operations (as PNG(NE) has no means to carry out such a prioritization of non-discretionary work).
63. The BCUC's decision to disallow 50 percent of PNG(NE)'s Integrity Dig Expenditures for 2026/2027 (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.⁵¹ 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.

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

PNG(NE) May Recover Reasonably Incurred Expenses

67. 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".⁵²
68. As is discussed in more detail in the next section, "The Material Impact of the Decision", as a result of the Decision, PNG(NE) 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(NE)'s ability to manage pipeline integrity as a reasonable operator). If

⁵¹ *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106, paras. 55-56.

⁵² See *Hemlock Valley Electrical Services Ltd. v. British Columbia (Utilities Commission)* (1993), 66 BCLR (2d) 1 at para. 55.

PNG(NE) 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

69. The Panel's decision to deny recovery of 50 percent of PNG(NE)'s Integrity Dig Expenditures for 2026/2027 will have a material, negative impact on PNG(NE), its ratepayers and its infrastructure.
70. As set out above, the Underlying Application included only the integrity expenditures that are strictly necessary to safely and reliably meet its loads. The amounts requested were relatively modest, and the 2025 digs completed have shown a high correlation of identified digs that require repairs (four out of seven): PNG(NE)'s Integrity Dig Expenditures identified and allowed for the repair of crack defects and other repairs which, if left undetected, could have impacted PNG(NE)'s ability to provide safe and reliable service. The Integrity Dig Expenditures leave no room for PNG(NE) to try and "prioritize" these activities, without severely diminishing PNG(NE)'s ability to manage pipeline integrity as a reasonable operator. This new information further supports PNG(NE)'s request for a reconsideration.
71. At this reduced spending level, PNG(NE) has a serious concern about its ongoing ability to operate. More specifically, PNG(NE) is concerned with:
 - (a) an inability to undertake integrity activities necessary to develop a more mature understanding of pipeline condition, which is required to effectively guide future integrity programs;
 - (b) delays to necessary work, resulting in continued pipe degradation to a point where replacement rather than repair becomes the only option, reducing the useful life of the assets;
 - (c) increased risk of pipeline failures arising from unknown defects, adversely impacting pipeline and public safety and PNG(NE)'s ability to safely and reliably serve customers;
 - (d) inability to ensure compliance with the Integrity Management Program and applicable codes, standards, and regulatory requirements;
 - (e) inability to demonstrate that PNG(NE) is acting as a prudent operator to the BCER, which regulates PNG(NE)'s technical compliance obligations; and
 - (f) risk of deterioration of PNG(NE)'s reputation with the BCER, exposing PNG(NE) to the risk of additional regulatory orders that would not otherwise have been imposed.
72. Should the BCUC order that this Reconsideration Application proceed to a hearing, PNG(NE) will seek leave to introduce evidence on the 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.

73. If PNG(NE) does not complete the required work, PNG(NE)'s ability to extend the life of the assets is at risk and further increases the risk of pipeline failure due to defects currently unknown. PNG(NE) must be permitted to mature its understanding of its pipeline condition so that it can develop its program and prevent these outcomes.
74. It is a legal error to leave PNG(NE) unable to recover its reasonable and prudently incurred (and necessary) expenses in its rates.

C. The Remedy Sought

75. PNG(NE) seeks to vary Order G-284-25 and the accompanying Decision, such that PNG(NE) be permitted to recover and be directed to reflect this full amount as part of its compliance filing.

PROPOSED RECONSIDERATION PROCESS

76. 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.

77. In light of the materiality of the impact of the Decision, and its impact on upcoming utility expenses and planned works (including, PNG(NE)'s forecast integrity management capital expenditures, which are largely carried out over the summer months), PNG(NE) proposes an efficient and focused reconsideration process to allow these matters to be considered in a timely, but fulsome manner.
78. There is time pressure on having certainty on the amount approved for recovery in rates, in order to allow PNG(NE) to plan for, and commence, 2026 integrity management activities. PNG(NE) submits that there is sufficient evidence before the BCUC to conclude that its Decision ought to be varied to permit PNG(NE) to recover in rates the full amount for Integrity Dig Expenditures, as sought in the Underlying Application, for the full Test Period (including 2026/2027). 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. PNG(NE) submits that further hearing process is not necessary and the BCUC may vary the Decision on Integrity Dig Expenditures without further process.
79. 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(NE) proposes a written hearing process being undertaken. In this case, PNG(NE) requests that the process also include an opportunity for an Evidentiary Update (with respect to the Integrity Management Capital Expenditures and the impact of a 50 percent reduction in

expenditures for 2026/2027), to include the new and further evidence outlined in this Reconsideration Application.

STAY OF COMPLIANCE FILING

80. Finally, in Order G-284-25, PNG(NE) 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.
81. On December 16, 2025, PNG(NE) 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(NE) 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(NE) has not filed the suspension request by that date.
82. 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.
83. PNG(NE) 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.
84. In this Reconsideration Application, PNG(NE) seeks reconsideration and variance of an aspect 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. PNG(NE) seeks to pause the compliance filing requirement until three weeks following the BCUC's decision, to allow PNG(NE) to prepare the necessarily paperwork. As set out in the Introduction, due to the interdependence in the financial modelling for PNG(NE) and PNG-West revenue requirements (i.e. transfers to capital, shared service cost recoveries), the compliance filings for both utilities must be prepared concurrently. As a result, PNG(NE) requests that a stay be granted until three weeks following the latter of the BCUC's decisions on the PNG(NE) and the PNG-West reconsideration applications.

REQUEST TO INCREASE INTERIM RATES

85. In light of PNG(NE)'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(NE) seeks an increase its interim rates, in order to reflect how the BCUC directed rates to be set in this Decision.

86. Attached at **Schedule "B"** is supporting information, including PNG(NE)'s high-level rationale for the request, illustrative revenue deficiency summaries, certain of the regulatory and rate schedules, bill comparisons, and additional analysis.
87. PNG(NE) seeks implementation of these interim rates, effective as of March 1, 2026.

CONCLUSION

88. In conclusion, PNG(NE) respectfully submits that it has established reasonable grounds for reconsideration of the Decision regarding the integrity management capital expenditures, and this Reconsideration ought to proceed to a hearing, with a written hearing process.
89. PNG(NE) further submits that a stay be granted, pending the outcome of this reconsideration, for PNG(NE) to file its compliance filing, until three weeks following the BCUC's decision.
90. Finally, PNG(NE) seeks to have its interim rates increased to reflect the Decision.

ALL OF WHICH IS RESPECTFULLY SUBMITTED.

January 27, 2026

Dated



Erica Miller, Farris LLP, counsel for PNG

SCHEDULE "A"

Erica Miller

From: Koosmann, Nicole <Nicole.Koosmann@bc-er.ca>

Sent: January 8, 2026 9:21 AM

To: Kyle Keith <kkeith@png.ca>

Cc: Parsonage, Kevin <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

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

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 on January 27, 2026, submitted 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.

Request for Approval to Revise 2026 Interim Rates

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 on January 27, 2026, filed an application requesting reconsideration of certain directives contained in G-284-25. 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

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.¹

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

¹ 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	
	\$	%	\$	%
PNG-West				
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%
Fort St. John (FSJ)				
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%
Dawson Creek (DC)				
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%
Tumbler Ridge (TR)				
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%)

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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

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.

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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	Application	Difference	
	Decision 2025	2025	Total	Subtotal
Operating				
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>	
Maintenance				
Labour	288	288	0	
Other	583	583	0	
Sub-total	<u>871</u>	<u>871</u>	<u>0</u>	
Administrative and General				
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>	
Total (O, M, A & G) Excluding Company Use Gas Cost	27,370	27,748	(378)	(378)
Transfers to Capital - Operating	(1,337)	(1,318)	(19)	
Transfers to Capital - Administrative & General	(1,017)	(1,067)	49	
Property Taxes	4,935	4,935	0	
Depreciation	10,716	10,716	0	
Amortization	13,435	7,654	5,782	
Other Income	(251)	(251)	0	5,812
Total Expenses Excluding Company Use Gas Cost	53,850	48,416	5,434	5,434
Income Taxes	1,894	537	1,357	
Return on Common Equity	20,286	20,300	(14)	
Short Term Debt	159	159	0	
Long Term Debt	9,612	9,586	26	1,369
Total Cost of Service Excluding Company Use Gas Cost	85,802	78,998	6,803	6,803
Company Use Gas Cost	528	745	(217)	
Total Cost of Service Including Company Use Gas Cost	86,329	79,743	6,586	
2024 to 2025 Cost of Service Increase / (Decrease)	26,453	19,649	6,804	
2024 to 2025 Margin (Increase) / Decrease	5,607	5,019	589	
2024 Integrity Deferral Increase / (Decrease)	2,000	2,000	0	
2025 Rate Smoothing Deferral Increase / (Decrease)	(25,085)	(12,036)	(13,049)	
2025 Revenue Deficiency / (Sufficiency)	8,975	14,632	(5,657)	
Average Rate Increase / (Decrease)	17.17%	27.57%	-10.40%	
Residential Rate Increase / (Decrease)	17.26%	27.78%	-10.51%	

Pacific Northern Gas Ltd.
(PNG-West Division)

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

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

Pacific Northern Gas Ltd.
(PNG-West Division)

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

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

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

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

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

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

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

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

**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**

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)
Residential (RS 1)	1,186,456	1,186,456	22,126,416	22,126,416	3,799,442	3.202	2.782	0.420	2.30
Granisle (RS 1 - Propane)	5,877	5,877	76,796	76,796	13,187	2.244	1.609	0.635	2.30
Commercial									
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
Total Commercial	1,353,796	1,353,796	18,056,645	18,056,645					
Seasonal Off-Peak (RS 6)	16,700	16,700	170,438	170,438	29,267	1.753	1.709	0.044	26.97
NGV (RS 7)	0	0	0	0	0	n.a.	0.000	0.000	0.00
Small Industrial									
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
Total Small Industrial	1,439,866	1,448,516	6,728,330	6,728,330					
Large Volume Industrial (RS 80)									
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				
Rio Tinto Alcan									
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.C. Hydro - Interruptible Transport	36,000	36,000	233,123	233,123	40,031	1.1120	0.7592	0.3528	1058.28
Total Large Industrial	1,212,000	1,243,492	5,110,304	5,110,304					
TOTAL	5,214,695	5,254,837	52,268,930	52,268,930	8,975,370				
Summary									
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				
Total	5,214,695	5,254,837	52,268,930	52,268,930	8,975,370				

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)
Residential (RS 1)	1,721,689	1,721,689	13,041,447	1,142,565	0.664	0.577	0.087	0.70
Commercial								
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
Small Industrial Sales (RS 4)	409,300	409,300	1,025,122	89,811	0.219	0.207	0.012	41.54
Industrial Transport								
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
Total	4,415,859	5,039,751	22,618,952	1,963,562				
Summary								
Sales	3,643,951	3,643,951	21,272,449	1,863,686				
Transportation	771,908	1,395,800	1,346,503	99,876				
Total	4,415,859	5,039,751	22,618,952	1,963,562				

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
Total Sales	231,647	231,647	2,572,433	(45,624)				
Industrial Transport (CNRL)	720,000	720,000	731,559	(12,975)	(0.018)	(0.018)	0.000	0.00
TOTAL	951,647	951,647	3,303,993	(58,599)				
Summary								
Sales	231,647	231,647	2,572,433	(45,624)				
Transportation	720,000	720,000	731,559	(12,975)				
Total	951,647	951,647	3,303,993	(58,599)				

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)
Residential (RS 1)	1,161,228	1,161,228	25,440,290	25,440,290	4,368,488	3.762	3.258	0.504	2.70
Granisle (RS 1 - Propane)	5,828	5,828	89,557	89,557	15,378	2.639	1.884	0.755	2.70
Commercial									
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
Total Commercial	1,286,816	1,286,816	20,312,287	20,312,287					
Seasonal Off-Peak (RS 6)	16,700	16,700	199,490	199,490	34,256	2.051	2.000	0.051	31.57
NGV (RS 7)	0	0	0	0	0	n.a.	0.000	0.000	0.00
Small Industrial									
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
Total Small Industrial	1,508,596	1,716,553	9,556,068	9,556,068					
Large Volume Industrial (RS 80)									
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					
Rio Tinto Alcan									
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.C. Hydro - Interruptible Transport	36,000	36,000	272,725	272,725	46,831	1.3009	0.8875	0.4134	1254.58
Total Large Industrial	1,212,000	1,243,492	5,972,932	5,972,932					
TOTAL	5,191,168	5,430,617	61,570,624	61,570,624	10,572,620				
Summary									
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				
Total	5,191,168	5,430,617	61,570,624	61,570,624	10,572,620				

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 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 (RS 1)	1,693,475	1,693,475	14,002,144	1,226,141	0.7240	0.627	0.097	0.76
Commercial								
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
Small Industrial Sales (RS 4)	409,300	409,300	1,118,108	97,911	0.239	0.226	0.013	45.29
Industrial Transport								
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
Total	4,385,007	5,007,923	24,397,327	2,118,300				
Summary								
Sales	3,606,918	3,606,918	22,933,939	2,008,281				
Transportation	778,089	1,401,005	1,463,388	110,019				
Total	4,385,007	5,007,923	24,397,327	2,118,300				

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
Total Sales	232,012	232,012	2,474,087	(43,627)				
Industrial Transport (CNRL)	720,000	720,000	718,599	(12,671)	(0.018)	(0.018)	0.000	0.00
TOTAL	952,012	952,012	3,192,686	(56,298)				
Summary								
Sales	232,012	232,012	2,474,087	(43,627)				
Transportation	720,000	720,000	718,599	(12,671)				
Total	952,012	952,012	3,192,686	(56,298)				

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**

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
Residential (RS 1)					
Monthly Basic Charge	\$13.34	\$2.30		\$15.64	\$2.30
Natural Gas					
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)
Total	18.938	2.782	0.634	22.354	3.416
Propane					
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)
Total	11.947	1.609	(0.417)	13.139	1.192

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
<u>Small Commercial Sales (RS 2)</u>					
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
<u>Propane</u>					
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
<u>Large Commercial Sales (RS 3)</u>					
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
<u>Commercial Transport (RS 22)</u>					
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
<u>Commercial Transport (RS 33)</u>					
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
<u>Small Industrial Sales (RS 4)</u>					
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
<u>Commercial Interruptible Sales (RS 5)</u>					
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
Seasonal Off-Peak (RS 6)					
Off Peak (Mar - Nov)					
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
Peak (Dec - Feb)					
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
NGV (RS 7)					
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
<u>Rio Tinto Alcan- Supp No. 7, 7A</u>					
Firm	3.9391	0.6936		4.6327	0.6936
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
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	-			-	-
	3.9991	0.6936	(0.0010)	4.6917	0.6926
<u>B.C. Hydro- Supp No. 10</u>					
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)
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	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<u>Interruptible Sales/Service</u>					
All Industrial T-Service Customers	4.3213	0.7592		5.0805	0.7592
Company Use	0.1280		(0.0280)	0.1000	(0.0280)
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	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<u>Industrial Firm Transport (RS 40)</u>					
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)
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	-			-	-
	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)
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	-			-	-
	4.3813	0.7592	(0.0010)	5.1395	0.7582
<u>Large Volume Industrial (RS 80)</u>					
Firm	1.0000	-		1.0000	-
Company Use	-			-	-
GCVA 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	-			-	-
GCVA 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
Residential (RS 1)					
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)
Total	9.146	0.577	0.610	10.333	1.187
Small Commercial (RS 2)					
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)
Total	7.508	0.424	0.606	8.538	1.030
Large Commercial (RS 3)					
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)
Total	6.271	0.306	(0.402)	6.175	(0.096)

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
Commercial Transportation (RS 23)					
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
Small Industrial (RS 4)					
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)
Small Industrial Service (RS 6)					
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
Small Industrial Service (RS 10)					
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
Residential (RS 1)					
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)
Total	8.948	0.577	0.610	10.135	1.187
Small Commercial (RS 2)					
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)
Total	6.971	0.424	0.606	8.001	1.030
Large Commercial (RS 3)					
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)
Total	5.723	0.306	(0.402)	5.627	(0.096)
Commercial Transportation (RS 23)					
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
<u>Small Industrial (RS 4)</u>					
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)
Total	4.869	0.207	(0.448)	4.628	(0.241)
<u>Small Industrial Service (RS 7)</u>					
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
<u>Residential (RS 1)</u>					
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)
Total	15.586	(0.262)	0.897	16.221	0.635
<u>Small Commercial (RS 2)</u>					
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)
Total	12.870	(0.190)	0.893	13.573	0.703
<u>Large Commercial (RS 3)</u>					
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)
Total	11.279	(0.152)	(0.561)	10.566	(0.713)
<u>Industrial Transport (CNRL)</u>					
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	-			-	-
Total	0.829	(0.018)		0.806	(0.023)

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
Residential (RS 1)								
Monthly Basic Charge	\$15.64	\$2.70		\$18.34	\$2.70	\$17.05	\$1.29	7.6%
Natural Gas								
Delivery Charge	18.898	3.258		22.156	3.258	20.592	1.564	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		
Total	22.354	2.441	0.897	25.692	3.338	23.084		
Propane								
Delivery Charge	10.899	1.884		12.783	1.884	11.882	0.901	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		
Total	13.139	1.884	0.897	15.920	4.645	14.507		

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
Small Commercial Sales (RS 2)								
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	-			-	-			
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		
Total	19.320	1.924	0.896	22.140	2.820	19.788		
Propane								
Monthly Basic Charge	\$15.64	\$2.70		\$18.34	\$2.70	\$17.05	\$1.29	7.6%
Delivery Charge	10.899	1.884		12.783	1.884	11.882	0.901	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		
Total	13.120	1.884	0.896	15.900	2.780	14.492		
Large Commercial Sales (RS 3)								
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	-			-	-			
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		
Total	14.941	2.199	0.896	18.036	3.095	16.475		

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
Commercial Transport (RS 22)								
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	-		-	-	-	-		
Total	17.158	1.924	(0.012)	19.070	1.912	17.206		
Commercial Transport (RS 33)								
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	-		-	-	-	-		
Total	12.773	2.199	(0.012)	14.960	2.187	13.890		
Small Industrial Sales (RS 4)								
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		
Total	7.658	1.026	0.912	9.596	1.938	8.615		
Commercial Interruptible Sales (RS 5)								
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		
Total	9.547	1.352	0.889	11.788	2.241	10.718		

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
Seasonal Off-Peak (RS 6)								
Off Peak (Mar - Nov)								
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		
Peak (Dec - Feb)								
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		
NGV (RS 7)								
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
<u>Rio Tinto Alcan- Supp No. 7, 7A</u>								
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		
<u>B.C. Hvdro- Supp No. 10</u>								
Monthly Demand Charge	\$7,221.19	\$1,254.58		\$8,475.77	\$1,254.58	\$7,861.94	\$613.83	7.8%
Interim Demand Charge Rider	-			-	-	-	-	
Interruptible Sales/Service	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		
<u>Interruptible Sales/Service</u>								
All Industrial T-Service Customers except West Fraser-Kitimat	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		
<u>Industrial Firm Transport (RS 40)</u>								
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		
<u>RS80 Large Volume Industrials</u>								
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
Residential (RS 1)								
Monthly Basic Charge	\$8.64	\$0.76		\$9.40	\$0.76	\$8.64	\$0.76	8.8%
Delivery Charge	7.191	0.623		7.814	0.623	7.190	0.624	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		
Total	10.333	(0.183)	0.917	11.067	0.734	9.575		
Small Commercial (RS 2)								
Monthly Basic Charge	\$8.65	\$0.76		\$9.41	\$0.76	\$8.65	\$0.76	8.8%
Delivery Charge	5.415	0.471		5.886	0.471	5.415	0.471	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		
Total	8.538	(0.335)	0.916	9.119	0.581	7.785		
Large Commercial (RS 3)								
Monthly Basic Charge	\$185.50	\$16.45		\$201.95	\$16.45	\$185.51	\$16.44	8.9%
Delivery Charge	4.007	0.350		4.357	0.350	4.009	0.348	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		
Total	6.175	0.350	0.911	7.436	1.261	6.580		

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
Commercial Transportation (RS 23)								
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		
Small Industrial (RS 4)								
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		
Small Industrial Service (RS 6)								
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		
Small Industrial Service (RS 10)								
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
Residential (RS 1)								
Monthly Basic Charge	\$8.64	\$0.76		\$9.40	\$0.76	\$8.64	\$0.76	8.8%
Delivery Charge	6.993	0.637		7.630	0.637	6.992	0.638	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		
Total	10.135	(0.169)	0.917	10.883	0.748	9.377		
Small Commercial (RS 2)								
Monthly Basic Charge	\$8.65	\$0.76		\$9.41	\$0.76	\$8.65	\$0.76	8.8%
Delivery Charge	4.878	0.444		5.322	0.444	4.878	0.444	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		
Total	8.001	(0.362)	0.916	8.555	0.554	7.248		
Large Commercial (RS 3)								
Monthly Basic Charge	\$185.50	\$16.45		\$201.95	\$16.45	\$185.51	\$16.44	8.9%
Delivery Charge	3.459	0.316		3.775	0.316	3.461	0.314	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		
Total	5.627	0.316	0.911	6.854	1.227	6.032		

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
Commercial Transportation (RS 23)								
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		
Small Industrial (RS 4)								
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		
Small Industrial Service (RS 7)								
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
Residential (RS 1)								
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		
Total	16.221	(1.437)	0.673	15.457	(0.764)	14.905		
Small Commercial (RS 2)								
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		
Total	13.573	(1.366)	0.672	12.879	(0.701)	12.262		
Large Commercial (RS 3)								
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		
Total	10.566	(0.145)	0.667	11.088	0.520	10.718		
Industrial Transport (CNRL)								
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**

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
Residential (RS1)							
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
Total	20.850	3.629	24.479	(1.395)	23.084	1.564	24.648
Residential (RS1P Propane)							
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
Total	12.587	1.966	14.553	(0.046)	14.507	0.901	15.408

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
Small Commercial Sales (RS2)							
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
Total	18.087	3.096	21.183	(1.395)	19.788	1.313	21.101
Small Commercial (RS2P Propane)							
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
Total	12.572	1.966	14.538	(0.046)	14.492	0.901	15.393
Large Commercial Sales (RS3)							
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
Total	14.235	2.286	16.521	(0.046)	16.475	1.051	17.526

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
Small Industrial (RS4)							
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
Total	7.623	1.038	8.661	(0.046)	8.615	0.501	9.116
Commercial Interruptible (RS5)							
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
Total	9.356	1.408	10.764	(0.046)	10.718	0.642	11.360

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
Seasonal Off-Peak (RS6)							
Off Peak (Mar-Nov)							
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
Total	12.813	2.078	14.891	(0.046)	14.845	0.955	15.800
Peak (Dec-Feb)							
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
Total	20.765	2.078	22.843	(0.046)	22.797	0.955	23.752
NGV (RS7)							
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
Total	5.715	-	5.715	(0.046)	5.669	-	5.669

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
Small Commercial Transportation (RS22)							
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
Total Delivery	15.505	3.096	18.601	(1.395)	17.206	1.313	18.519
Large Commercial Transportation (RS33)							
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
Total Delivery	11.650	2.286	13.936	(0.046)	13.890	1.051	14.941
PNG Company Use Rate	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)

LOW CARBON ENERGY RATES	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
Residential (RS1-LCE)							
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
Total	48.350	3.629	51.979	(1.395)	50.584	1.564	52.148
Small Commercial Sales (RS2-LCE)							
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
Total	45.587	3.096	48.683	(1.395)	47.288	1.313	48.601

Pacific Northern Gas Ltd.
(PNG-West Division)

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

LOW CARBON ENERGY RATES	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
Large Commercial Sales (RS3-LCE)							
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
	11.723	2.286	14.009	(0.052)	13.957	1.051	15.008
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	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
	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
Total	41.735	2.286	44.021	(0.046)	43.975	1.051	45.026
Small Industrial (RS4-LCE)							
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
	5.341	1.038	6.379	(0.052)	6.327	0.501	6.828
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	5.268	1.038	6.306	(0.046)	6.260	0.501	6.761
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
Total	35.123	1.038	36.161	(0.046)	36.115	0.501	36.616

Pacific Northern Gas Ltd.
(PNG-West Division)

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

LOW CARBON ENERGY RATES	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
Commercial Interruptible (RS5-LCE)							
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
Seasonal Off-Peak (RS6-LCE)							
Off Peak (Mar-Nov)							
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
Peak (Dec-Feb)							
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.
(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
<u>Rio Tinto Alcan- Supp No. 7, 7A</u>							
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
Total Delivery	4.2900	0.8476	5.1376	(0.0460)	5.0916	0.3797	5.4713
<u>Rio Tinto Alcan- Supp No. 7, 7A - Interruptible</u>							
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
Total Delivery	4.6979	0.9273	5.6252	(0.0460)	5.5792	0.4168	5.9960
<u>B.C. Hydro- Supp No. 10</u>							
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
Interruptible Delivery	\$ 6,590.17	\$ 1,271.77	\$ 7,861.94	\$ -	\$ 7,861.94	\$ 613.83	\$ 8,475.77
Company Use	4.6239	0.9273	5.5512	-	5.5512	0.4168	5.9680
Interim Rate Adjustment Rider	0.1470	-	0.1470	(0.0520)	0.0950	-	0.0950
GCVA Co. Use Rider	4.7709	0.9273	5.6982	(0.0520)	5.6462	0.4168	6.0630
LCCR 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
Total Delivery	4.6979	0.9273	5.6252	(0.0460)	5.5792	0.4168	5.9960
<u>Industrial Interruptible Transportation Service</u>							
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
Total Delivery	4.6979	0.9273	5.6252	(0.0460)	5.5792	0.4168	5.9960

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
RS40 - Firm Transportation							
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
Total Delivery	5.2683	1.0376	6.3059	(0.0460)	6.2599	0.5009	6.7608
RS40 - Interruptible Transportation Service							
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
Total Delivery	4.6979	0.9273	5.6252	(0.0460)	5.5792	0.4168	5.9960
RS80 - Large Volume Industrial Transportation Service							
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
Total Delivery	1.0020	-	1.0020	0.0060	1.0080	-	1.0080
RS80 - Interruptible Transportation Service							
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
Total Delivery	1.0020	-	1.0020	0.0060	1.0080	-	1.0080

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
Residential (RS1)							
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
Total	10.393	0.331	10.724	(1.149)	9.575	0.624	10.199
Small Commercial (RS2)							
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
Total	8.682	0.252	8.934	(1.149)	7.785	0.471	8.256
Large Commercial (RS3)							
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
Total	6.413	0.157	6.570	0.010	6.580	0.348	6.928

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
Small Industrial (RS4)							
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)
Total	2.355	-	2.355	-	2.355	-	2.355
	4.693	0.106	4.799	0.010	4.809	0.217	5.026
Small Industrial Transportation >15,000 GJ (RS6)							
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
Total Delivery	2.6292	0.1161	2.7453	0.0100	2.7553	0.2427	2.9980
Small Industrial Transportation (RS10)							
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
Total Delivery	1.2049	0.0539	1.2588	0.0100	1.2688	0.1127	1.3815
Commercial Transportation (RS23)							
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
Total Delivery	4.235	0.181	4.416	0.010	4.426	0.386	4.812
PNG Company Use Rate							
	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)

LOW CARBON ENERGY RATES	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
Residential (RS1-LCE)							
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
Total	37.893	0.331	38.224	(1.149)	37.075	0.624	37.699
Small Commercial (RS2-LCE)							
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
Total	36.182	0.252	36.434	(1.149)	35.285	0.471	35.756

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

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

LOW CARBON ENERGY RATES	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
Large Commercial (RS3-LCE)							
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
Total	33.913	0.157	34.070	0.010	34.080	0.348	34.428
Small Industrial (RS4-LCE)							
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
Total	32.193	0.106	32.299	0.010	32.309	0.217	32.526

Pacific Northern Gas (N.E.) 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
Residential (RS1)							
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
Total	10.195	0.331	10.526	(1.149)	9.377	0.638	10.015
Small Commercial (RS2)							
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
Total	8.145	0.252	8.397	(1.149)	7.248	0.444	7.692
Large Commercial (RS3)							
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
Total	5.865	0.157	6.022	0.010	6.032	0.314	6.346

Pacific Northern Gas (N.E.) 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
Small Industrial (RS4)							
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
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
GCVA Commodity Rider	(0.294)	-	(0.294)	-	(0.294)	-	(0.294)
Subtotal Commodity	2.355	-	2.355	-	2.355	-	2.355
Total	4.961	0.106	5.067	0.010	5.077	0.251	5.328
Small Industrial Transportation Service (RS7) (Bypass Rate)							
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	-	-	-	-	-	-	-
Total Delivery	0.2050	-	0.2050	-	0.2050	-	0.2050
Commercial Transportation (RS23)							
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
Total Delivery	3.687	0.181	3.868	0.010	3.878	0.356	4.234
PNG Company Use Rate	2.115	-	2.115	1.141	3.256	-	3.256

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

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

LOW CARBON ENERGY RATES	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
Residential (RS1-LCE)							
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
Total	37.695	0.331	38.026	(1.149)	36.877	0.638	37.515
Small Commercial (RS2-LCE)							
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
Total	35.645	0.252	35.897	(1.149)	34.748	0.444	35.192

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

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

LOW CARBON ENERGY RATES	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
Large Commercial (RS3-LCE)							
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
Total	33.365	0.157	33.522	0.010	33.532	0.314	33.846
Small Industrial (RS4-LCE)							
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
Total	32.461	0.106	32.567	0.010	32.577	0.251	32.828

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
Residential (RS1)							
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
Total	17.437	(0.637)	16.800	(1.895)	14.905	(0.248)	14.657
Small Commercial (RS2)							
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
Total	14.649	(0.492)	14.157	(1.895)	12.262	(0.178)	12.084
Large Commercial (RS3)							
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
Total	11.542	(0.396)	11.146	(0.428)	10.718	(0.141)	10.577
Industrial Transport (RS5 - CNRL)							
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
Total Delivery	0.846	(0.040)	0.806	0.0060	0.812	(0.0180)	0.794
PNG Company Use Rate							
	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)

LOW CARBON ENERGY RATES	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
Residential (RS1-LCE)							
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
Total	44.937	(0.637)	44.300	(1.895)	42.405	(0.248)	42.157
Small Commercial (RS2-LCE)							
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
Total	42.149	(0.492)	41.657	(1.895)	39.762	(0.178)	39.584
Large Commercial (RS3-LCE)							
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
Total	39.042	(0.396)	38.646	(0.428)	38.218	(0.141)	38.077

**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**

Exhibit E – Other Regulatory Schedules

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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
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%

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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
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>

2025-2027 RRA
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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	

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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)	

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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

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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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Test Years 2025-2027
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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

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**

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 \$ %		
Residential:	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)	-	-	
Carbon Tax*		0.0000	-	0.0000	166.47	-	-	
			\$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.

Small Commercial:	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)	-	-	
Carbon Tax*		0.0000	-	0.0000	816.95	-	-	
			\$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 \$ %		
Residential:	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)	-	-	
Carbon Tax*		0.0000	-	0.0000	91.15	-	-	
			\$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.

Small Commercial:	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)	-	-	
Carbon Tax*		0.0000	-	0.0000	392.46	-	-	
			\$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	
						\$	%
Residential:	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.

Small Commercial:	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	
						\$	%
Residential:	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.

Small Commercial:	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	
						\$	%
Residential:	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.

Small Commercial:	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	
						\$	%
Residential:	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.

Small Commercial:	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 (N.E.) Ltd. Application for Reconsideration and Variance
of British Columbia Utilities Commission Order G-284-25
on the Pacific Northern Gas (N.E.) Ltd. PNG(NE) 2025 to 2027 Revenue Requirements
and Stay of Proceedings

BOOK OF AUTHORITIES

1. *Pipeline Regulation*, BC Reg 210/2010
2. *Utilities Commission Act*, RSBC 1996, c 473
3. *British Columbia Hydro and Power Authority v. British Columbia (Utilities Commission)* (1996) 20 BCLR (3d) 106
4. *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.

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Energy Resource Activities Act

PIPELINE REGULATION

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

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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 m³, 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.

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

Chris Sanderson, J. Christian and
A.M. Dobson-Mack Counsel for the Appellant

Mark M. Moseley Counsel for the Respondent
The British Columbia Utilities Commission

Carol Reardon Counsel for the Respondent
Intervenor, British Columbia Energy Coalition

Michael P. Doherty Counsel for the Respondent
Intervenor, Consumer's Association of Canada
(B.C. Branch) et al

D.W. Burseey Counsel for the Respondent
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 demand¹. The process results in the selection of that mix of resources which yields the preferred² 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 ratemaking³, 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-1 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
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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
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	Total	15.97	12.42	10.16
			% Increase	17.42