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ORDER NUMBER
G-164-18

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

Pacific Northern Gas(NE) Ltd.
2018–2019 Revenue Requirements Application

BEFORE:

D. A. Cote, Commissioner/Panel Chair
A. K. Fung, QC, Commissioner
B. A. Magnan, Commissioner

on August 30, 2018

ORDER

WHEREAS:

A. On November 30, 2017, Pacific Northern Gas (N.E.) Ltd. (PNG[NE]) filed its 2018–2019 Revenue Requirements Application (RRA) for its Fort St John/Dawson Creek (FSJ/DC) and Tumbler Ridge (TR) divisions with the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA) seeking approval to, among other things, increase 2018 and 2019 delivery rates (Application);

B. By Order G-193-17 dated December 19, 2017, the BCUC approved the following delivery rate increases, among others, on an interim and refundable/recoverable basis effective January 1, 2018:

   1. an 8.8 percent increase from $4.060/GJ to $4.419/GJ for FSJ Residential service and a 9.3 percent increase from $3.862/GJ to $4.221/GJ for DC Residential service;
   2. a 7.4 percent increase from $3.227/GJ to $3.465/GJ for FSJ Small Commercial service and an 8.9 percent increase from $2.690/GJ to $2.928/GJ for DC Small Commercial service;
   3. a 26.7 percent increase from $7.152/GJ to $9.064/GJ for TR Residential service; and
   4. a 23.7 percent increase from $5.854/GJ to $7.239/GJ for TR Small Commercial service;

   Order G-193-17 also approved an increase to the RSAM rate rider from $0.472GJ to $0.540/GJ on an interim and refundable/recoverable basis for the FSJ/DC Division and a decrease to the RSAM rate rider from $1.256/GJ to $0.373/GJ on an interim and refundable/recoverable basis for the TR Division. Further, Order G-193-17 established a regulatory timetable including a February 28, 2018 deadline for PNG(NE) to file its updated application (Amended Application);

C. British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and Tenants Resource and Advisory Centre (BCOAPO et al.) registered as an intervener in the proceeding;

D. By Order G-31-18 dated February 2, 2018, the BCUC established a written public hearing process, including two rounds of BCUC and intervener information requests (IRs), followed by final and reply arguments;

E. On February 28, 2018, PNG(NE) filed its Amended Application;

F. On June 26, 2018, the BCUC reopened the evidentiary record and issued two rounds of Panel IRs to PNG(NE) and requested submissions from parties on the need for additional arguments on the specific content of the responses to the Panel IRs. The BCUC did not receive any requests for additional arguments; and

G. The BCUC has considered the Application, Amended Application, evidence and submissions of the parties.

NOW THEREFORE pursuant to sections 45(5) and 59 to 61 of the UCA and for the reasons attached as Appendix A to this order the BCUC orders as follows:

1. PNG(NE)'s request for recovery of the 2018 revenue requirement and resultant delivery rate changes for the FSJ/DC and TR divisions presented in the Amended Application is approved on a permanent basis, effective January 1, 2018, subject to the adjustments identified by PNG(NE) in IRs and in argument as well as to the adjustments outlined in these directives.

2. The 2018 RSAM rate rider set forth in the Amended Application is approved on a permanent basis, effective January 1, 2018.

3. PNG(NE)'s request for recovery of the 2019 revenue requirement and resultant delivery rate changes for the FSJ/DC and TR divisions presented in the Amended Application is approved on an interim and refundable/recoverable basis, effective January 1, 2019, subject to the adjustments identified by PNG(NE) in IRs and in argument as well as to the adjustments outlined in these directives. The 2019 rates will remain interim pending the BCUC review of the negative salvage compliance filing and the BCUC's determination on the timing of the phase-in period for the negative salvage accounting.

4. PNG is directed to file a proposal within 60 days of Order G-151-18 for a report to the BCUC, to be filed annually, which outlines its future construction of extensions and new facilities as well as any significant system modifications or additions that are planned. The proposal is to be filed with the PNG-West report, filed pursuant to directive 5 of Order G-151-18, and in accordance with Section 2.5 of the reasons for decision attached to this order.

5. The following changes and additions to PNG(NE)'s deferral accounts are approved:

    a. The creation of new deferral accounts for each of FSJ/DC and TR bearing interest at PNG(NE)'s short-term interest rate to levelize the impact of the combined net revenue deficiencies for 2018 and 2019 to be fully amortized in 2019;

    b. The transfer of the 2016 unaccounted for gas (UAF) losses for the FSJ/DC division above 1.5 percent totalling 145,572 GJs valued at $276,296 before tax from the temporary UAF deferral account to the UAF volume deferral account to be recovered from customers via the Company Use rider, and dissolution of the temporary UAF deferral account;

   c. The proposal to fully amortize the balance of the TR division Legacy Deferred Income Taxes deferral account in 2018;

   d. The dissolution of the Legacy Deferred Income Taxes deferral account and the non-pension postretirement benefit (NPPRB) Regulatory Asset Deferral account for each of FSJ/DC and TR following final amortization of the remaining balances in 2018.

6. PNG(NE) FSJ/DC division is approved to continue the use of the UAF volume deferral account on the basis that the UAF volume forecast for each of 2018 and 2019 are set based on using 1 percent of deliveries UAF loss factor. PNG(NE) must file an application with the BCUC to obtain approval to record UAF losses for the FSJ/DC division above 1.5 percent in this deferral account.

7. PNG(NE) TR division is approved to continue the use of the UAF volume deferral account on the basis that the UAF volume forecast for each of 2018 and 2019 are set to zero with PNG(NE) recording the variance between zero and up to 1 percent without requiring further BCUC approval. PNG(NE) must file an application with the BCUC to obtain approval to record UAF losses for the TR division above 1 percent in this deferral account.

8. PNG(NE) is approved to apply the depreciation rates based on the findings of the depreciation study set forth in the Amended Application, effective January 1, 2018, subject to the adjustments outlined in these directives.

9. PNG(NE)'s proposal to exclude provisions for negative salvage values from depreciation expense is denied.

10. PNG(NE) is directed to incorporate positive salvage values for Account 485 in its depreciation rates to coincide with the timing and methodology for incorporation of negative salvage in depreciation rates.

11. PNG(NE) is directed to amortize land rights in accordance with the recommendations made in the Concentric Advisors ULC Depreciation Report, effective January 1, 2019.

12. PNG(NE) 's forecast of 340 new services is rejected and it is directed to calculate and refile as part of its compliance filing made pursuant to directive 17 of this order a capital expenditure amount for FSJ/DC New Services based on the installation of 230 new services in each of 2018 and 2019.

13. PNG(NE)'s forecast for Distribution Mains is rejected and it is directed to calculate and refile as part of its compliance filing made pursuant to directive 17 of this order a capital expenditure amount for FSJ/DC Distribution Mains reflecting no more than the average actual expenditure for Distribution Mains over the past three years with an inflation factor reflecting changes in the BC CPI over this period.

14. PNG(NE) is directed to remove the capital expenditures related to the North Pine pipeline project from its 2018 and 2019 revenue requirements in its compliance filing pursuant to directive 17 of this order.

15. PNG(NE) is directed to file in future RRAs, in addition to information provided for the test period, the total project costs by year for any projects that span beyond the test period, along with those being requested over a particular test period.

16. PNG(NE) is directed to file a CPCN application for the Baldonnel Line Lowering project prior to proceeding with Phase 2 of the project and construction.

17. PNG(NE) is directed to re-calculate the 2018 and 2019 revenue requirements and delivery rate changes in a compliance filing and file revised regulatory schedules with the BCUC reflecting the changes outlined in this order and further described in the attached reasons for decision by no later than 30 days from the date of this order.

18. PNG(NE) is directed to inform all customers of the final 2018 permanent rates and resulting bill impact and the 2019 interim rates and resulting bill impact by way of written notice to be included with the customer invoice following the filing of its compliance filing pursuant to directive 17 of this order.

19. PNG(NE) is directed to collect from/refund to customers the difference between the 2018 interim rates and the 2018 permanent rates over the balance of 2018.

DATED at the City of Vancouver, in the Province of British Columbia, this 30th day of August 2018.

BY ORDER

Original signed by:

D. A. Cote
Commissioner

Attachment

Pacific Northern Gas (N.E.) Ltd.
2018–2019 Revenue Requirements Application

Reasons for Decision

August 30, 2018

Before:
D. A. Cote, Commissioner/Panel Chair
A. K. Fung, QC, Commissioner
B. A. Magnan, Commissioner

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1.0 Introduction

1.1 Background

Pacific Northern Gas (N.E.) Ltd. (PNG[NE]) operates a gas processing plant and natural gas distribution system providing service to 21,400 natural gas customers in Fort St John (FSJ), Dawson Creek (DC), and Tumbler Ridge (TR). It is a wholly owned subsidiary of Pacific Northern Gas (PNG), a wholly owned subsidiary of AltaGas Utility Holdings (Pacific) Inc., which is in turn a wholly-owned subsidiary of AltaGas Ltd. (AltaGas). PNG also has a western division, PNG-West, which is the owner and operator of a natural gas transmission and distribution system located in the west central part of British Columbia commencing just north of Prince George at Summit Lake and extending west to Kitimat and Prince Rupert. Along this corridor PNG-West serves 20,400 natural gas customers with an additional 150 propane customers being served in the community of Granisle, BC. [1] A system map encompassing all of PNG's operations is shown in Figure 1.

Figure 1: PNG System Map PNG-West Division and PNG(NE)[2]

On November 30, 2017, PNG(NE) submitted its 2018-2019 Revenue Requirements Application (RRA) to the BCUC seeking approval to amend its rate schedules for the PNG(NE) division to be effective January 1, 2018. On December 19, 2017, the BCUC issued Order G-193-17 approving interim delivery rates as well as the applied for Rate Stabilization Adjustment Mechanism (RSAM) on an interim basis, effective January 1, 2018. In addition, this order established a preliminary regulatory timetable covering the period up to February 28, 2018 when PNG(NE) was scheduled to file an updated application (Amended Application). PNG(NE) states that the Amended Application generally includes all of the Original Application with revisions arising from evidentiary update information inclusive of revised demand forecasts, updated cost forecasts in addition to the impact of 2017 actual operating results on rate-base items.[3] Henceforth, any further reference to the Application will include the amendments set out in the Amended Application as applicable.

[1] Exhibit B-1-1, FSJ/DC, p. 2.
[2] PNG System Map PNG-West Division and PNG(NE) (August 2018), retrieved from: https://www.png.ca/images/PNG-ServiceAreas-WebVersion-20180313-v05-FINAL.jpg.
[3] Exhibit B-1-1, FSJ/DC, p. 1.

1.2 Regulatory process

On February 2, 2018, the BCUC, by Order G-31-18 established a regulatory timetable with a written hearing as supported by the parties. The timetable included two rounds of information requests (IRs) as well as final arguments from the parties and a reply argument from the applicant.

The British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens; Organizations of BC, and Tenants Resource and Advisory Centre (BCOAPO et al.) registered as the sole intervener.

Following the scheduled process and submission of reply argument by PNG(NE), the Panel issued two rounds of Panel IRs requesting further information and clarification of a number of issues. Parties were provided the opportunity to file additional arguments to address the specific content of the responses to the Panel IRs. The BCUC did not receive any requests for additional arguments.

1.3 Approvals sought

PNG(NE) seeks an order from the BCUC granting the approvals as described in the following:

FSJ/DC division[4]

1. Approval, effective January 1, 2018, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2018" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated in the Amended Application and to adjustments and undertakings identified through the regulatory review process.
2. Approval, effective January 1, 2019, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2019" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated in the Amended Application and to adjustments and undertakings identified through the regulatory review process.
3. Approval of PNG(NE)'s proposal to create a short term interest bearing rate deferral account in 2018 to levelize the impact of the combined net revenue deficiencies for 2018 and 2019 to be fully amortized in 2019.
4. Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, including:
    a. Further to BCUC Order G-105-17, approval pursuant to sections 58 to 61 of the *Utilities Commission Act*, to move the 2016 unaccounted for gas (UAF) losses above 1.5 percent from the temporary UAF deferral account to the UAF volume deferral account and to be recovered from customers via the Company Use rider, PNG(NE)'s historic mechanism for recovering/refunding UAF losses/gains;

[4] PNG(NE) Final Argument, pp. 3–4.

   b. Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in 2018; and

   c. Approval to eliminate the NPPRB Regulatory Asset Deferral account following the final amortization of the remaining balance in 2018;

5. Approval of the depreciation expense based on the findings of a new depreciation study as set forth in the Application.

6. Approval to continue the unaccounted for gas (UAF) volume deferral account to record the difference between forecast and actual UAF volumes in 2018 and 2019 based on using 1.0 percent of deliveries UAF loss factor for 2018 and 2019 and requiring PNG (NE) to apply for BCUC approval to record actual 2018 or 2019 UAF losses above 1.5 percent in the deferral account.

7. Approval of a 2018 debit RSAM rate rider equal to $0.442/GJ and a 2019 debit RSAM rate rider equal to $0.059/GJ.[5]

<u>TR division</u>[6]

1. Approval, effective January 1, 2018, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2018" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

2. Approval, effective January 1, 2019, on a permanent basis pursuant to sections 58 to 61 of the *Utilities Commission Act*, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes presented under Tab Schedules, Tab 6 in the table entitled "Summary of Proposed Gas Delivery Charge Rate Changes Effective January 1, 2019" as set forth under the heading "Proposed Rate Changes for Rev. Def. ($/GJ)", subject to changes incorporated into the Amended Application and to adjustments and undertakings identified through the regulatory review process.

3. Approval of PNG(NE)'s proposal to create a short term interest bearing rate deferral account in 2018 to levelize and smooth the impact of the combined net revenue deficiency for 2018 and 2019 to be fully amortized in 2019.

4. Approval of the changes and additions to PNG(NE)'s deferral accounts and amortization expenses for 2018 and 2019, pursuant to sections 58 to 61 of the *Utilities Commission Act*, as detailed in Section 2.9 – Amortization, and as shown in the Continuity of Deferred Charges tables set forth in this same exhibit under Tab Schedules, Tab 2, pages 12 through 15, including:

   a. Approval to fully amortize the Legacy Deferred Income Taxes deferral account balance in 2018;

   b. Approval to eliminate the Legacy Deferred Income Taxes deferral account following the final amortization of the remaining balance in 2018; and

   c. Approval to eliminate the NPPRB Regulatory Asset deferral account following the final amortization of the remaining balance in 2018.

5. Approval of the depreciation expense based on the findings of a new depreciation study as set forth in the Application.

[5] Exhibit B-1-1, FSJ/DC Tab Schedules, Tab 6 Rates, pp. 19 & 39.
[6] PNG(NE) Final Argument, pp. 4–6.

6. Approval to continue the unaccounted for gas (UAF) volume deferral account on the basis, pursuant to sections 58 to 61 of the *Utilities Commission Act,* that the UAF volume forecast for 2018 and 2019 are set at zero with PNG(NE) recording the variance between zero percent and a loss of up to 1.0 percent without having to seek further BCUC approval. PNG(NE) would be required to file an application with the BCUC to obtain approval to record UAF losses above 1.0 percent in this deferral account.
7. Approval of a 2018 debit RSAM rate rider equal to \$0.312/GJ and a 2019 debit RSAM rate rider equal to \$0.049/GJ.[7]

1.4 Issues arising and organization of the decision

There were a number of issues arising within the proceeding, each of which is identified and addressed in the sections following.

Section 2.0 outlines issues that are addressed in the PNG-West Decision that also apply to PNG(NE). These include:

- Proposed rate deferral mechanism
- Handling of UAF gas losses
- GIS and Asset Record Modernization projects
- Depreciation study and related issues
- CPCN Requirements

Section 3.0 focuses on operating, maintenance, administrative and general expenses.

Section 4.0 addresses issues related to PNG(NE)'s proposed capital expenditures.

Section 5.0 examines issues related to deferral accounts, specifically the amortization of the Legacy Deferred Income Taxes deferral account.

Section 6.0 addresses other matters which have arisen over the course of the proceeding. These include the capital structure and rate of return as well as the potential for rate harmonization among the divisions.

With the exception of those issues identified and discussed in the following sections, the Panel finds the PNG(NE) 2018-2019 RRA filing and associated approval requests to be just and reasonable and accordingly approves them.

2.0 Issues addressed in the PNG-West Decision

A number of issues are discussed and addressed in some detail within the BCUC reasons for decision accompanying Order G-151-18 in the PNG-West 2018-2019 RRA proceeding (PNG-West Decision).[8] Many of these are not unique to PNG-West but also apply to the PNG(NE) proceeding. The issues in common include the following:

[7] Exhibit B-1-1, TR Tab Schedules, Tab 6 Rates, pp. 10 and 21.
[8] PNG-West 2018-2019 RRA proceeding, Order G-151-18 with Reasons for Decision, dated August 15, 2018 (PNG-West Decision).

- The proposed rate deferral mechanism;
- Handling of UAF losses;
- The GIS and Asset Record Modernization projects;
- Issues related to the Depreciation Study; and
- CPCN requirements.

This section addresses how these issues apply to divisions within PNG(NE). The reader is encouraged to read the PNG-West Decision in conjunction with these reasons for decision.

2.1 Proposed rate deferral mechanism

PNG(NE), in keeping with PNG-West's proposal for a rate deferral mechanism, proposes to establish a rate deferral mechanism whereby the full impact of combined rate changes for 2018 and 2019 are balanced over a two year period. This would be achieved by recording $165,000 of FSJ/DC's 2018's revenue deficiency in an interest bearing deferral account resulting in a revenue deficiency for FSJ/DC of $0.816 million in 2018 and $0.842 million in 2019 and rate increases of 6.3 percent and 6.1 percent for 2018 and 2019, respectively. For TR once the rate deferral mechanism is applied, the revenue deficiency totals $0.206 million for 2018 and $0.230 million for 2019 with a resultant residential rate increase of 19.1 percent and 18.1 percent in 2018 and 2019, respectively.[9]

BCOAPO et al. took no position in this proceeding with respect to the proposed rate deferral mechanism but as discussed in Section 6.2 does have concerns with the impact of the large increase in delivery rates on its ratepayers.

BCUC determination

Consistent with the PNG-West Decision the Panel approves the proposed rate deferral mechanism for the PNG(NE) divisions as outlined in the Application. As noted, employment of the proposed rate deferral mechanism balances the impact on rates over the two-year period by smoothing out the rate fluctuations that would have otherwise occurred.

2.2 Handling of UAF gas losses

The American Gas Association describes unaccounted for gas (UAF) as follows:

> The difference between the total gas available from all sources, and the total gas accounted for as sales, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times. In cycle billings, an amount of gas supply used but not billed as of the end of a period.[10]

In the BCUC decision in the PNG(NE) 2016-2017 RRA proceeding, the BCUC gave approval for PNG(NE) to seek BCUC approval only in those cases where UAF amounts exceeded the UAF loss cap of 1.5 percent for FSJ/DC and 1 percent for TR. [11] In the PNG(NE) 2018-2019 RRA, PNG(NE) has applied to continue to use the UAF volume

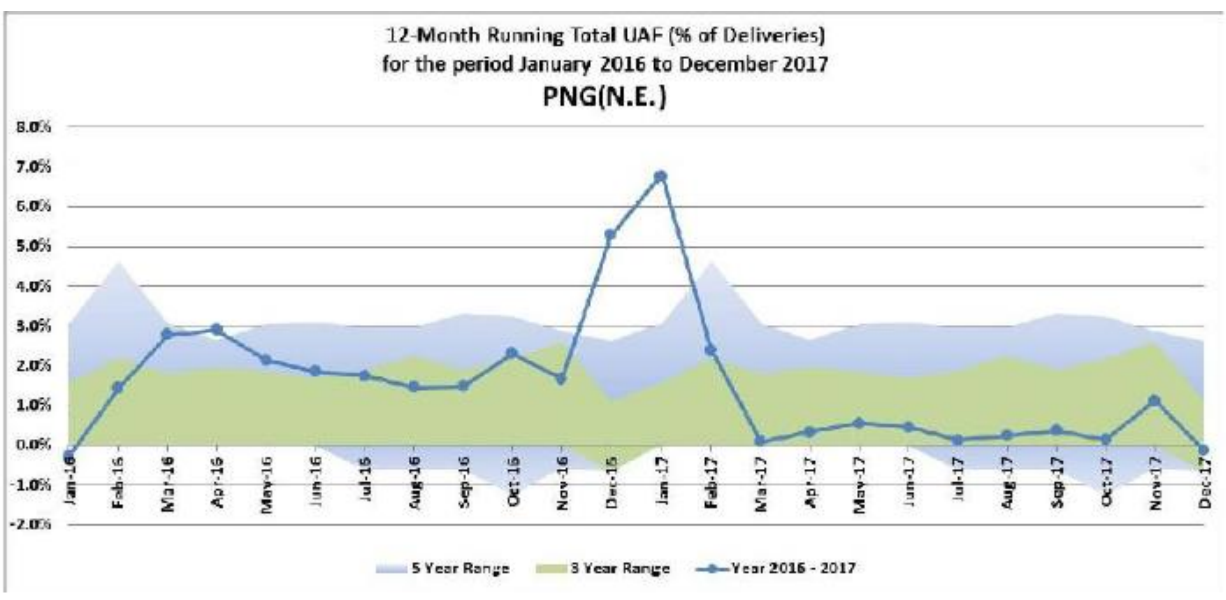
[9] Exhibit B-1-1, FSJ/DC, p. 6; Exhibit B-1-1, TR, p. 6.
[10] American Gas Association – Glossary (August 2018), retrieved from: https://www.aga.org/natural-gas/glossary/u/
[11] PNG(NE) 2016-2017 RRA for the PNG(NE) Service Area proceeding, Final Order G-132-16 with Reasons, dated August 10, 2016.

deferral account to record the difference between forecast and actual UAF. The application for FSJ/DC is made on the basis of using one percent as a loss factor for the 2018 and 2019 forecast and the requirement that the company apply for BCUC approval to record actual UAF losses above 1.5 percent in the deferral account. For TR, the application is made on the basis that the UAF volume forecast for 2018 and 2019 are set at zero and PNG(NE) would be required to file an application with the BCUC to obtain approval to record UAF losses above 1.0 percent in the deferral account.[12]

On February 24, 2017, PNG(NE) applied to the BCUC for approval to record the 2016 UAF losses for the FSJ/DC division above 1.5 percent in the UAF deferral account. PNG(NE) submitted that 2016 actual UAF losses were 203,081 GJ which converts to approximately 5.3% of its deliveries to its sales and transport customers. At the approved company used gas commodity cost of $1.898/GJ, the value of the UAF losses above 1.5 percent that would require approval amounted to $276,296 before tax.[13] Under Order G-105-17, the BCUC denied this request and directed the company to establish a separate deferral account on a temporary basis to record these losses until such time as the disposition of the excess UAF (over 1.5 percent) had been determined. At that time, the BCUC also directed PNG(NE) to prepare a report summarizing the results of its further examination of the data, calculations, and reasons for the increased losses as well as a proposal for these losses to be reviewed as part of its next RRA[14].

As directed, PNG(NE) filed a UAF report summarizing its investigation of the increased UAF losses occurring between January 1, 2016 and December 31, 2016 as part of the 2018-2019 RRA. Within the report, PNG(NE) identified two separate incidents where significant UAF losses occurred; the first of these was in February and March and the second in December 2016. Figure 2 depicts the running total of UAF losses as a percentage of deliveries graphically from January 2016 to December 2017[15].

Figure 2: 12-Month Running Total UAF (% of Deliveries) for the Period January 2016 to December 2017



[12] Exhibit B-1-1, FSJ/DC, p. 11 and Exhibit B-1-1, TR, p. 25.
[13] Exhibit B-1-1, FSJ/DC, Appendix B, p. 9.
[14] ibid., p. 2.
[15] ibid., pp. 5–6.

As outlined in Figure 2, in February and March 2016, PNG(NE) recorded approximately 135,000 GJ of UAF losses, increasing the running total UAF to just under 3.0 percent of deliveries over the previous 12 months. This was up from close to zero percent as of January 2016 and there was no significant reversal in the ensuing months. This was followed in December, 2016 with another large loss leading to a cumulative loss of just under 7.0 percent of total deliveries. As with PNG-West, in January 2017 PNG(NE)'s running total trend reversed and the UAF exhibited a declining trend culminating in the running total of UAF losses by the end of 2017 being near zero.[16]

PNG(NE) explains that determining monthly UAF volumes is dependent upon the unbilled estimate, which is the volume of natural gas delivered but not yet billed to customers. This is calculated by determining the number of unbilled days of service (DOS) from when a customer was last billed to the end of the current calendar month. PNG(NE) states that in February 2016 it implemented a change in how unbilled DOS are reported which resulted in a reduction of the estimated residential customer unbilled consumption and, as a result, an increase in the UAF loss. With respect to the December 2016 UAF losses, PNG(NE) explains that this is likely a result of a residential and small commercial unbilled estimate that incorrectly reflected the impact of a significant cold snap that occurred in the middle of that month.[17]

PNG(NE) states that with the exception of January 2017, the running 12-month total UAF trend falls within historical bounds for the balance of 2017. It also states that it remains diligent in the monitoring of its UAF volumes, identifying any anomalies and examining the causes of such anomalies. Looking ahead, it is evaluating the costs and benefits of accessing more accurate customer information such as using advanced metering infrastructure or the use of a new residential end-use survey in an effort to improve its unbilled estimate under these circumstances. Having undertaken this review of the 2016 UAF causes, PNG(NE) states that it has a high level of confidence that the causes of the high UAF in 2016 were isolated events rather than ongoing systemic issues. As a result, PNG(NE) has requested BCUC approval of the UAF balance above 1.5 percent totalling 145,572 GJs valued at $276,296 before tax.[18]

BCUC determination

While UAF loss totals differ from those reported by PNG-West, the explanations as to why they occurred provided by PNG(NE) mirror those of PNG-West, which were accepted by the BCUC. Consistent with the PNG-West Decision, the Panel accepts the PNG(NE) Unaccounted for Gas Report for the Period January 2016 to December 2017 and its explanations as to the events resulting in high UAF losses in 2016. **Accordingly, Panel has determined that based on these explanations it is appropriate to approve recording of the 2016 UAF losses for FSJ/DC above 1.5 percent in the UAF volume deferral account. Therefore, PNG(NE) is directed to transfer those losses related to 2016 totalling 145,572 GJs valued at $276,296 before tax from the temporary UAF deferral account to the UAF volume deferral account and close the temporary UAF deferral account. There being no reason put forward to justify changing the current approved practice, the Panel also approves for PNG(NE) to continue to record a UAF loss of up to 1.5 percent for FSJ/DC and 1 percent for TR in 2018 and 2019 without having to seek further BCUC approval.**

2.3 GIS and Asset Record Modernization projects

In the PNG-West Decision the BCUC accepted the capital expenditures for the Geographical Information System (GIS) and the asset record modernization (ARM) projects as being reasonable. PNG has allocated a share of the costs for these projects to both FSJ/DC and the TR divisions. The GIS project is estimated to cost approximately $2.4 million and is scheduled to be completed over three years. Of this amount $852,000 has been allocated to

[16] Exhibit B-1-1, FSJ/DC, Appendix B, pp. 4–6
[17] ibid., pp. 5–6.
[18] ibid., pp. 8–9.

FSJ/DC with $30,000 being allocated to TR. The ARM project is estimated to cost $1,472,000 and is scheduled to be completed over the next five years. FSJ/DC has been allocated approximately $353,000 of the estimated cost while TR has been allocated approximately $60,000. In keeping with the PNG-West Decision, **the Panel accepts the allocations to FSJ/DC and TR as reasonable and accepts PNG(NE)'s filing of 2018 and 2019 capital expenditures for the GIS and ARM projects, respectively. The incorporation of the project costs into rates is approved upon completion of the projects, subject to any prudency review of expenditures that may arise.**

2.4 Depreciation study and related issues

2.4.1 Introduction

PNG(NE) states that it last updated depreciation rates for the PNG companies in 2011. In 2017, PNG engaged Concentric Advisors ULC (Concentric) to undertake a review of depreciation rates for all service areas based on the plant in service at December 31, 2016. PNG(NE) reports that consistent with the previous study, Concentric relied on various statistical methods, operation interviews with PNG staff and informed judgement based on their experience in the natural gas industry to estimate depreciation rates. For most accounts, the straight-line method using the average life group procedure for assets in a particular class has been used to calculate the annual and accrued depreciation while the annual and accrued depreciation are based on amortization accounts for certain general plant accounts. PNG(NE) reports that the 2017 depreciation methodologies application is consistent with that of the 2010 Depreciation study. In addition, it reports that a key finding of the Concentric 2017 Depreciation Study that is consistent with other peer group utilities is an extension of the useful life of assets in certain accounts. When incorporated, this has effectively reduced the depreciation expense for both 2018 and 2019.[19]

Panel discussion

The Panel reviewed the Depreciation Study prepared by Concentric and notes that the methodology used is consistent with previous depreciation studies. The Panel finds that, based on the methodology used and the analysis undertaken, the Depreciation Study results in a reasonable set of recommendations for depreciation rates for each service area. Therefore, the Panel accepts the Concentric 2017 Depreciation Study and depreciation expense as submitted except in the specifically identified areas where PNG(NE) has deviated from the recommendations outlined. These include net salvage values, negative and positive, as well as the depreciation of land rights. Each of these is addressed as follows.

2.4.2 Depreciation study issues

2.4.2.1 Inclusion of negative salvage costs

The incorporation of negative salvage values into depreciation expense allows for the current period recovery of future anticipated costs of an asset's removal that would otherwise occur at the end of its life. By contrast, there are certain instances where positive salvage results due to the experience of realizing proceeds on the disposition of an asset. Currently, the PNG companies do not incorporate negative salvage as part of its annual depreciation expense and only partially incorporates the recommendations provided by Concentric regarding positive salvage, as outlined below.[20]

[19] Exhibit B-1-1, FSJ/DC, pp. 51–53.
[20] ibid., pp. 51–53.

Concentric's recommendations for handling negative salvage

In its 2017 Depreciation Study, Concentric specifically recommends that negative salvage values be incorporated into the depreciation rates for certain accounts. This recommendation has been made with reference to the PNG companies' current practice of foregoing the provision for the estimated costs of asset retirement and recording actual costs of removal at the time they are incurred.[21]

Concentric states that the incorporation of negative salvage results in a $3.0 million increase or 30 percent of the PNG companies' total depreciation forecast. While acknowledging the impact of including negative salvage, Concentric explains that delaying negative salvage introduction "will increase the inter-generational inequity from customers that pay for the eventual removal costs from those that benefited from those removed assets." Concentric also states that inclusion of a negative salvage allowance provides for proper matching of expenses to revenues and intergenerational equity is assured. In support of its position Concentric notes that the allocation of negative salvage costs over the life of the asset is appropriate and equitable and is also in accord with authoritative texts and most Uniform Systems of Accounts citing those published in Alberta, Ontario, the National Energy Board of Canada and the U.S. Federal Energy Regulatory Commission (FERC). Moreover, the inclusion of negative salvage percentages is widely accepted in regulatory jurisdictions throughout North America, although not all utilities have chosen to do so. Canadian regulators favouring allowing the inclusion of negative salvage rates include the following:

- The British Columbia Utilities Commission (for FortisBC Energy)
- The Alberta Utilities Commission
- The Manitoba Utilities Board
- The Ontario Utilities Board
- The Regie de l'Energie du Quebec;
- The Nova Scotia Utility and Review Board
- The National Energy Board

Concentric explains that the problem with delaying collection until negative salvage costs are incurred is that it results in higher revenue requirements over the remaining life of the asset. Moreover, the longer this is delayed, the higher the depreciation rate will be. Therefore, each year this process is delayed results in an increase in the differential between net and calculated book value and, as a result, depreciation rates increase proportionally.[22]

In defining depreciation for regulated utilities, FERC's Uniform System of Accounts states it is:

> The loss in service value not restored by current maintenance incurred in connection with the consumption or prospective retirement of property in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance". [23]

Concentric notes that the words "service value" are the operative words in FERC's definition. These are defined in FERC's Uniform System of Accounts as "the difference between the original cost and its net salvage". Negative salvage value is further defined as the salvage value of the property to be retired less the removal cost or the cost of demolishing, dismantling, tearing down or otherwise removing electric plant.

[21] ibid., pp. 51 & 52.
[22] Exhibit B-1-1, FSJ/DC, Appendix C, pp. I-3–I-6.
[23] Ibid., p. 1-4

In Concentric's view the revenue requirements over time resulting from an "expensing as incurred" approach are greater than those that result from the accrual of negative salvage during the life of the asset in those instances where the rate of return is included in the revenue requirements. It explains that "as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods."[24]

PNG(NE)'s position

PNG(NE) states that while the incorporation of negative salvage values in depreciation rates matches the cost of the asset to the service it provides and preserves intergenerational equity, PNG(NE) has made the decision to not incorporate it in its depreciation rates. It justifies this by pointing to the materiality of the negative salvage estimates and resulting rate impacts of incorporation of these estimates as a basis for its position. If it were accepted, the depreciation expense for FSJ/DC in 2018 would increase by $823,000 and by another $857,000 in 2019. Those for TR would increase by $190,000 and another $194,000 respectively for 2018 and 2019.[25] The resulting impact on PNG(NE) ratepayers would be an increase of 7.1 percent for FSJ/DC while rates in Tumbler Ridge would increase by 21.4 percent with small decreases for both divisions expected in 2019.[26]

PNG(NE) states that it does not record a provision for the cost to ultimately retire assets because, due to the indeterminate timing and scope of asset retirements, it is not possible to make a reasonable estimate of fair market value of the liability. It points out that under ASC 410-2-25-4 of US Generally Accepted Accounting Principles (GAAP), the fair value of an asset obligation is required only if a reasonable estimate of fair value can be made. If not, "the liability shall be recognized when a reasonable estimate of fair value can be made." In PNG(NE)'s view, a reasonable estimate for retirement costs can only be made at the time of disposal noting that its discussion of US GAAP provisions refers to asset obligations related to legal obligations as there is no requirement to provide provisions for removal of asset costs which do not arise from a legal obligation.[27]

With reference to PNG-West, PNG acknowledges that it would consider offsetting the immediate impact on customer rates by amortizing the Option Fee Payment Deferral Account. However, it notes that PNG(NE) does not have an equivalent credit deferral account to offset the negative salvage recording impact and PNG does not foresee implementing different accounting treatments between divisions. With respect to the costs related to the implementation of negative salvage into depreciation rates, PNG(NE) asserts that it cannot determine the extent of the costs at this time. To do so it would need to assess the viability of using its existing financial system to record the negative salvage values and potentially there may be a requirement for one-time system changes.[28]

Finally, PNG(NE) states that if the Concentric recommendation regarding negative salvage were adopted it would reluctantly consider a long transition period given the significant delivery rate impact on what are the highest delivery rates in BC.[29]

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[24] ibid., pp. I-4–I-5.
[25] Exhibit B-1-1, FSJ/DC, p. 52; Exhibit B-1-1, TR, p. 46.
[26] Exhibit B-3, BCUC IR 20.1; Exhibit B-5, BCUC IR 25.2.
[27] Exhibit B-5, BCUC IR 28.1.
[28] ibid., BCUC IR 27.2 & 24.2.
[29] Exhibit B-3, BCUC IR 20.3.1 & 25.4.1.

Position of the parties

In its Final Argument, BCOAPO et al. states that it does not propose that the recommendations made by Concentric in the 2017 Depreciation Study, especially regarding negative salvage values, be implemented in any way other than proposed by PNG(NE).[30] In response, PNG(NE) reiterates that it does not recommend implementing negative salvage estimates in depreciation rates at this time due to the significant adverse rate impacts that would result.[31]

BCUC determination

Concentric makes a strong case for the inclusion of negative salvage in depreciation rates where required. While the inclusion of negative salvage in depreciation rates is not universal among North American regulatory jurisdictions, it is widely accepted. Moreover, in Concentric's view, the incorporation of negative salvage in depreciation rates is effective in matching the cost of the asset to its provision of service in a manner that best addresses intergenerational equity. On these points the Panel agrees. If negative salvage were incorporated, ratepayers who enjoyed the benefits of the service would also pay for its removal at its life end. This appropriately matches costs with the timing of service received and ensures that future ratepayers are not saddled with costs for services they did not enjoy or did so only on a limited basis. Moreover, as stated by Concentric, if negative salvage is not incorporated, higher revenue requirements and rates will result in the future.

With reference to PNG-West the BCUC determined that the inclusion of negative salvage in depreciation rates is appropriate.[32] The Panel is of the same view for the PNG(NE) divisions which are closely linked to PNG-West. **Accordingly, based on the evidence presented, the Panel determines that the inclusion of negative salvage in depreciation rates for PNG(NE) FSJ/DC and TR divisions is appropriate and directs PNG(NE) to incorporate negative salvage in their depreciation rates going forward in coordination with PNG-West.** However, in making this determination the Panel is mindful of the impact on PNG(NE)'s rates, especially those of TR. In keeping with this, the BCUC has determined that a phase-in period would be most appropriate to moderate the immediate impacts of the transition. To better understand the impacts of varying transitional periods, the Panel in the PNG-West proceeding has directed PNG-West to file within 45 days of Order G-151-18 a report detailing the following:

- The impact on PNG-West and PNG(NE) rates for each of the following phase-in time periods; 3 years, 5 years, 7 years and 10 years;
- A description of how PNG intends to handle the accounting for negative salvage over the phase-in period and the method it proposes to use to charge customers over the phase-in period; and
- A cost estimate for any required system changes to handle negative salvage and options for their implementation for PNG-West and PNG(NE).

Once this has been prepared, an appropriate process to review the report and transition to the inclusion of net salvage in depreciation rates for both PNG-West and PNG(NE) will be determined.

The rates effective January 1, 2019 will remain interim pending the review of the above-noted compliance filing and the BCUC's determination on the timing of the phase-in period for the negative salvage accounting.

[30] BCOAPO Final Argument, p. 6.
[31] PNG(NE) Reply Argument, p. 3.
[32] PNG 2018–2019 RRA, Final Order G-151-18 with Reasons for Decision, dated August 15, 2018, pp. 34–35.

2.4.2.2 Positive salvage

PNG(NE) states that the 2010 Depreciation Study recommended positive salvage values be incorporated into depreciation rates for Account 484, Transport Equipment and Account 485, Heavy Work Equipment. It reports that the recommendation for Account 484 from the 2010 study was followed due to its experience of receiving proceeds from the disposition of these assets. However, on the basis of the company's experience of not realizing any proceeds on disposition of Account 485, it opted not to incorporate positive salvage. PNG(NE) states that after further review it concurs with the recommendations of Concentric in the current Depreciation Study and agrees that 10 percent as recommended would be an appropriate provision for Account 485 net salvage. If incorporated, the depreciation expense would be lower in 2018 by $11,900 and in 2019 by $12,300 for FSJ/DC and lower by $300 for both years for TR. In its response to IRs, PNG(NE) sates that it is "agreeable to reflect this recommendation in its final regulatory schedules." However, in its Final Argument, PNG(NE) states it prefers to adopt this recommendation to coincide with implementation of provisions for negative salvage.[33]

BCUC determination

In accordance with the recommendations of the 2017 Depreciation Study and PNG(NE)'s assessment, the Panel directs PNG(NE) to incorporate positive salvage for Account 485 in its depreciation rates. As requested by the company, this change will coincide with the timing and methodology for incorporation of negative salvage in depreciation rates**.**

2.4.2.3 Depreciation of land rights

PNG(NE) states that consistent with the 2010 Depreciation Study, the 2017 Depreciation Study recommends land rights be depreciated over a period of 75 years. PNG(NE) notes that in the past it had determined that land rights had an indefinite life and should not be depreciated; a position it continues to take in the current Application. If depreciation of land rights were incorporated the impact on depreciation for FSJ/DC would be greater by $9,900 and for TR by $100.[34]

In making an assessment that land rights have an indefinite life and therefore should not be depreciated, PNG(NE) offers the following explanation:

> All agreements for provincial right of ways and providing for access to fee simple lands imply access for an indefinite period of time. This in indicated by the use of contractual language such as: "so long as required by grantee", "in perpetuity", "as long as desired by grantee" to describe the term for which many of these agreements apply. With the introduction of the BC Oil and Gas Commission in 1999, the standard term for provincial government agreements for land rights was changed to a period of 30 years, with provision to be a "monthly occupier" thereafter, subject to all provisions of the original agreement unless a written agreement is entered into to the contrary. Registered statutory right of way agreements with private landowners continue to be issued with terms that are perpetual in nature.[35]

PNG(NE) continues, stating that its access under existing land rights has not been challenged nor is it expected to be in the future as, under the Land Titles Act and the Gas Utility Act, it has the right to expropriate land on which its assets are situated. However, PNG(NE) acknowledges that it is unaware of any other Canadian gas

[33] Exhibit B-1-1, FSJ/DC, p.52; Exhibit B-1-1, TR, p.46; PNG(NE) Final Argument, p.16.
[34] Exhibit B-1-1, FSJ/DC, p. 52; Exhibit B-1-1, TR, p.46.
[35] Exhibit B-5, BCUC IR 32.1.

distribution utility that applies the same land rights methodology and confirms the normal accounting process is to amortize land rights.[36]

BCUC determination

The Panel directs PNG(NE) to amortize the value of land rights effective in 2019. While PNG(NE) has provided assurances to the contrary, the Panel is not persuaded that over the longer term these land rights will continue in perpetuity. But perhaps more importantly, this approach is standard accounting practice among other Canadian utilities and there is no reason it should not apply to PNG(NE).

2.5 CPCN requirements

In the PNG-West Decision the BCUC raised a number of concerns with respect to specific capital projects where significant work had been undertaken prior to the BCUC being notified. With earlier notification the BCUC may have requested a CPCN in some of these instances. The issue raised by the Panel in that proceeding was how best to report capital expenditures and determine the need for CPCN applications prior to the initiation of construction.

In the PNG-West Decision the Panel determined there was a need to develop a process to allow PNG-West's future capital expenditures to be considered in advance of construction and assess where a CPCN process would be helpful. Accordingly, PNG-West was ordered to file a proposal for future capital expenditure reporting which would allow for an assessment of these expenditures prior to construction being initiated and the opportunity for the BCUC to require a CPCN if and when it deemed necessary.

BCUC determination

The Panel acknowledges that the issues that were raised within the PNG-West proceeding were related to specific capital projects for PNG-West and similar issues were not raised in this proceeding. However, the Panel notes that issues related to the filing of capital expenditure plans and CPCN requirements have equal application to all PNG divisions. Therefore, **because of this, the Panel has determined that there is also a need to develop a process to allow PNG(NE)'s future capital expenditures to be considered in advance of construction and assess where a CPCN process would be in the public interest. Accordingly, the Panel orders PNG(NE) to file a proposal within 60 days of Order G-151-18 for a report to the BCUC, to be filed annually which outlines its future construction of extensions and new facilities as well as any significant system modifications or additions that are planned. PNG(NE)'s submission is to be filed with that of PNG-West and include recommendations for:**

- The form the annual report should take;
- The timing of the report;
- The regulatory review process;
- The level of detail to be required;
- Description of capital projects to be included/excluded from the report; and
- Any recommendations for minimum dollar thresholds**.**

[36] Exhibit B-5, BCUC 32.1 & 32.3.

3.0 Operating, maintenance, administrative and general expenses

PNG(NE) is requesting recovery of the following operating, maintenance and administrative and general (OMA) expenses for 2018 and 2019 as outlined in Table 1 and Table 2: [37]

Table 1: FSJ/DC Operating, Maintenance, and Administrative and General Expenses

Fort St. John/ Dawson Creek (FSJ/DC)	2017 Forecast	2018 Test Year	2019 Test Year
Operating (before transfers to capital)	$5,552,000	$5,931,000	$6,036,000
Maintenance	$392,000	$421,000	$429,000
Administrative & General (before transfers to capital)	$2,971,000	$2,904,000	$2,957,000
Less: transfers to capital - operating	$ (181,000)	$ (230,000)	$ (284,000)
Less: transfers to capital – admin. & gen.	$ (491,000)	$ (274,000)	$ (406,000)
Total	**$8,243,000**	**$8,752,000**	**$8,732,000**

Table 2: TR Operating, Maintenance, and Administrative and General Expenses

Tumbler Ridge (TR)	2017 Forecast	2018 Test Year	2019 Test Year
Operating (before transfers to capital)	$680,000	$728,000	$746,000
Maintenance	$80,000	$82,000	$84,000
Administrative & General (before transfers to capital)	$292,000	$250,000	$255,000
Less: transfers to capital - operating	$ (19,000)	$ (26,000)	$ (23,000)
Less: transfers to capital – admin. & gen.	$ (40,000)	$ (17,000)	$ (12,000)
Total	**$993,000**	**$1,017,000**	**$1,050,000**

The forecast OMA expenses are subject to adjustments and corrections identified during the regulatory review process, as outlined by PNG(NE) in section 13.2 of its Final Argument.[38] The 2018 forecast OMA expenses are $509,000 or 6.2 percent higher and $24,000 or 2.4 percent higher than the 2017 forecast OMA expenses for FSJ/DC and TR, respectively.[39] With respect to FSJ/DC, the increase is primarily attributable to $168,000 less overall transfers to capital due to a reduction of forecast capital expenditures compared to the consolidated

[37] Exhibit B-1-1, FSJ/DC, pp. 32, 35 & 37; Exhibit B-1-1, TR, pp. 26, 30 & 32.
[38] PNG(NE) Final Argument, p. 25.
[39] Exhibit B-1-1, FSJ/DC, pp. 32, 35 & 37: $5,371,000 + $392,000 + $2,480,000 = $8,243,000; Exhibit B-1-1, TR, pp. 26, 30 & 32: $661,000 + $80,000 + $252,000 = $993,000.

capital expenditures of all the divisions and changes to estimated labour spent on capital projects. In addition, the increase is attributable to an increase of $379,000 in operating expenses in 2018. PNG(NE) submits that the primary drivers of the increase in operating expenses include:[40]

i. Additional engineering projects including digital data mapping (DDM) and the implementation of a GIS, which are projects shared by the PNG companies. The DDM project will identify geological and hydrological hazards, while the GIS project (discussed in Section 2.3 of these reasons for decision) will provide access to accurate, trusted and complete information on the PNG companies' key assets anywhere within PNG's service territory.[41] The 2018 forecast operating cost for the DDM and GIS projects for FSJ/DC is $36,466 and $70,000, respectively, with comparable costs forecast for 2019 of $36,552 and $70,000, respectively;[42]

ii. Labour cost increases attributable to a new engineering position, which is required to manage both capital and O&M project priorities, and champion strategic initiatives;[43]

iii. Licencing costs for the Computerized Maintenance Management System (CMMS), which is a stand-alone project that will replace the PNG companies' current asset management system.[44] The 2018 and 2019 forecast operating costs for the CMMS for FSJ/DC are $82,765 and $83,208, respectively;[45] and

iv. General inflationary pressures.

The above items are also the main drivers of the increase in operating expenses in the TR division. In addition to these items, the increase in forecast 2018 OMA expenses as compared to the 2017 forecast for TR is due to higher amine and emission monitoring costs. The increase in OMA expenses is partially offset by lower pension and non-pension post-retirement benefit costs recorded to administrative and general.[46] Similar to FSJ/DC, a reduction in overall transfers to capital is expected due to a reduction of forecast capital expenditures compared to the consolidated capital expenditures of all the divisions and changes to estimated labour spent on capital projects.

The forecast 2019 OMA expenses are comparable to the 2018 forecast, with a decrease of $20,000 or 0.2 percent in FSJ/DC and an increase of $33,000 or 3.2 percent in TR. The increase in TR is mainly due to inflation, greater automobile expense allocation to operating costs due to lower planned capital expenditures in 2019 and higher forecast for company use gas.[47]

Positions of the parties

BCOAPO et al. raises several issues related to PNG(NE)'s OMA expenses, which are discussed below.

<u>Automotive Costs</u>

BCOAPO et al. states that its understanding is that the 2018 forecast for the Automotive line item of Account 685, "General Operations", is related to the 2016 actual expenses inflated by 2 percent. Given this understanding, BCOAPO et al. questions why the forecast 2018 automotive costs recorded in Account 685 for

[40] Exhibit B-1-1, FSJ/DC, p. 33; Exhibit B-5, BCUC IR 22.3.
[41] Exhibit B-13, Panel IR 1.1.
[42] Exhibit B-9, BCUC IR 61.5 & 83.2.
[43] Exhibit B-5, BCUC IR 13.7.
[44] Exhibit B-13, Panel IR 1.1.
[45] Exhibit B-5, BCUC IR 13.4 & 13.8.
[46] Exhibit B-1-1, TR, pp. 26, 28 & 33.
[47] ibid., Sections 2.3.1, 2.3.5 & 2.3.8, pp. 26, 28 & 29.

FSJ/DC are $346,774, which are "in considerable excess" of the actual 2016 costs of $237,041 plus 2 percent. Further, BCOAPO et al. states that its understanding is that PNG's vehicle maintenance costs will be lower, given that PNG intends to perform more of this work in-house. While acknowledging that any adjustment to the approved allocation methodology will affect all divisions' revenue requirements, BCOAPO et al. invites PNG to address this issue.[48]

By way of background, PNG(NE) explains that the forecast automotive costs are generated by PNG on a consolidated basis (for all divisions within PNG-West and PNG(NE)) by inflating the prior year actual costs by 2 percent plus an incremental increase in consideration of recent cost experience and anticipated changes in underlying costs, such as rising fuel prices. The consolidated costs are then allocated to PNG-West and the PNG(NE) divisions based on a pro rata of operating and maintenance (O&M) and capital labour costs.[49] The forecast and actual automotive costs allocated to operating and capital expenses for each division and the total automotive costs on a consolidated basis are reproduced in Table 3, which includes the automotive costs recorded to Account 685:[50]

Table 3: Automotive Costs

	2019 Forecast	2018 Forecast	2017 Forecast	2017 Actual	2016 Actual
Consolidated automotive costs – total	$1,054,502	$1,033,825	$1,097,363	$900,724	$961,660
FSJ/DC automotive costs – operating	$347,542	$347,044	$332,089	$260,541	$258,712
FSJ/DC automotive costs – capital	$99,669	$63,735	$68,734	$53,575	$48,059
TR automotive costs – operating	$52,286	$48,574	$46,280	$21,214	$11,028
TR automotive costs – capital	$322	$76	$457	$1,071	$3,482
PNG-West automotive costs – operating	$465,201	$432,547	$521,411	$455,097	$562,444
PNG-West automotive costs – capital	$89,481	$141,849	$128,392	$109,226	$77,935

In response to BCOAPO et al., PNG(NE) further explains that the consolidated forecast is allocated to PNG-West and the PNG(NE) divisions on a pro rata basis using the forecast O&M and capital labour costs for each

[48] BCOAPO Final Argument, p. 9.
[49] Exhibit B-5, BCUC IR 11.2 & 13.12.1; Exhibit B-8, BCUC IR 38.2–38.4; due to the timing of the Application PNG forecast its 2018 consolidated automotive costs by inflating the 2016 actual costs.
[50] Exhibit B-5, BCUC IR 13.12.1 Tables.

division.[51] For the FSJ/DC division specifically, the forecast 2018 automotive costs are greater than 2 percent of the 2016 actuals due to a higher pro rata allocation based on forecast operating labour costs for 2018 over the actual pro rata allocation to operating costs as determined by the applied forecast and cost allocation methodology.[52]

<u>Other Administrative and General Expenses</u>

BCOAPO et al. also questions why "Other Administrative and General" expenses in the TR division have increased by 67.4 percent over a seven-year period; an increase that is more significant than the division's other OMA expenses.[53]

In response, PNG(NE) states that the increase in 2018 compared to 2011 is "primarily due to increased shared services cost allocations from PNG-West."[54] PNG(NE) explains that the increase in shared services cost allocations reflects changes to the shared services cost allocation model which were approved by the BCUC in its 2013 Decision. The changes reflect a more accurate allocation of PNG-West costs to PNG(NE).[55]

BCUC determination

The Panel notes that the forecast 2018 OMA expenses before transfers to capital show an overall increase in 2018 over 2017 forecast of $341,000 or 3.8 percent and $8,000 or 0.8 percent in FSJ/DC and TR, respectively. With respect to the $341,000 forecast increase in 2018 over 2017 forecast in FSJ/DC, PNG(NE) has explained that approximately $189,000 are attributable to the new DDM, GIS and CMMS projects. Once deducted this leaves approximately $152,000 or 1.7 percent of the proposed increase attributable primarily to the new engineering position and inflationary pressures. The Panel accepts PNG(NE)'s explanation for the increase in 2018 OMA expenses over 2017 forecast and PNG(NE)'s explanation of why these new projects and initiatives are necessary. The OMA expenses before transfers to capital in 2019 are comparable to 2018 with an overall increase of $166,000 or 1.8 percent and $25,000 or 2.4 percent, in FSJ/DC and TR, respectively, which is in line with recent inflation and consistent with PNG(NE)'s explanation for the increase. Accordingly, the Panel finds the requested 2018 and 2019 OMA expenses to be reasonable. In addition, the Panel is persuaded that the overall change in transfers to capital in FSJ/DC and TR during 2018 and 2019 is consistent with the forecast change in capital expenditures relative to the consolidated capital expenditures of all of PNG's divisions and with the changes in estimated labour spent on capital projects. **Therefore, subject to the adjustments identified by PNG(NE) in IRs and in arguments and any adjustments resulting from the PNG-West Decision that impact shared services costs, the Panel approves the 2018 and 2019 OMA expenses requested.**

With respect to BCOAPO et al.'s question regarding the automotive costs forecast for FSJ/DC, the Panel accepts PNG(NE)'s explanation that the forecast increase to FSJ/DC's automotive costs for 2018 is greater than 2 percent of 2016 actual costs primarily due a higher pro rata allocation based on forecast 2018 operating labour costs over the actual pro rata allocation. Further, PNG(NE) also explains in its evidence that, in addition to the inflationary increase, it also applies to the consolidated forecast an incremental increase in consideration of recent cost experience and anticipated changes in underlying costs, such as rising fuel prices and the carbon tax. Based on the explanations provided by PNG(NE) and the fact the PNG(NE) has acted in accordance with the established allocation methodology utilized for PNG-West, the Panel accepts the automotive costs as outlined in this Application. However, the Panel notes the variance between actual costs on a divisional basis and those that

[51] PNG(NE) Reply Argument, para. 23.
[52] PNG(NE) Reply Argument, para. 24.
[53] BCOAPO Final Argument, p. 11.
[54] PNG(NE) Reply Argument, para. 38.
[55] PNG(NE) Reply Argument, para. 38.

are forecasted using this allocation methodology. Given this variance the Panel directs PNG to review and assess the effectiveness of the automotive cost allocation methodology with respect to variances in forecast and actual expense allocations in its next RRA and, based on this assessment, provide recommendations for future handling and allocation of costs among the PNG divisions.

4.0 Capital expenditures

4.1 Capital projects review

PNG(NE) forecasts capital expenditures of $7,433,431 and $6,276,127 for FSJ/DC and $1,021,573 and $197,625 for TR in 2018 and 2019 respectively. PNG(NE) separates its capital expenditures into two categories: recurring and non-recurring. Recurring capital expenditures are those that are required on an ongoing basis such as new services, meter and regulator purchases and investigative dig cut-outs. Non-recurring capital expenditures are those related to specific projects of varying sizes such as pipeline repairs or replacements. PNG(NE)'s total capital expenditures also include projects that have been carried forward from a previous year.

Table 4 below provides a summary of PNG(NE)'s actual and forecast capital expenditures for 2016 and 2017 and its forecast capital expenditures for 2018 and 2019, according to division and expenditure type.

Table 4: Actual and Forecast Capital Expenditures [56]

Division	2016 Actual	2016 Forecast	2017 Actual	2017 Forecast	2018 Forecast	2019 Forecast
FSJ/DC						
Planned - Recurring	$3,805,399	$3,899,215	$3,533,205	$3,648,251	$3,212,068	$3,663,474
Planned – Non-recurring	$1,292,294	$2,622,757	$273,958	$342,529	$4,221,363	$2,612,652
Carryforward Projects	$169,680	$71,583	$833,639	-	-	-
Total Capital Expenditures	$5,267,373	$6,593,555	$4,640,803	$3,990,780	$7,433,431	$6,276,127
TR						
Planned - Recurring	$10,192	$56,734	-	$45,388	$59,160	-
Planned – Non-recurring	$227,094	$477,721	$199,325	$445,613	$62,413	$197,625
Carryforward Projects	$48,983	-	$122,380	-	$900,000	-
Total Capital Expenditures	$286,269	$534,455	$321,705	$491,001	$1,021,573	$197,625

For FSJ/DC, PNG(NE) reports capital under spending of $1,326,182 for 2016. This was offset somewhat by capital over spending of $650,023 in 2017 resulting in a net under expenditure of $676,159 for the two-year period. Similarly, for TR, PNG(NE) reports a capital under spending of $248,186 for 2016 and a further under spending of $169,295 for 2017, resulting in a total under spending of $417,481 over the two-year period.

[56] Exhibit B-1-1, FSJ/DC, pp. 60–71, 82–88; Exhibit B-1-1, TR, pp. 54–58, 69–72 (Table created by BCUC).

Planned – Recurring capital projects

For FSJ/DC planned recurring capital makes up the largest part of forecasted capital expenditures for 2018 while for TR, recurring capital expenditures are a much smaller part of total capital expended. As outlined in Table 4, PNG(NE) had minor under expenditure variances in 2016 and in 2017 for the Planned – Recurring capital projects category within FSJ/DC with a small over expenditure for TR over the same period. However, while total recurring capital expenditures were relatively close to forecast in FSJ/DC, there were significant variances within the actual project categories. Most notable of these were the New Services, Distribution Mains and Distribution Main Improvement-Other categories.

With respect to New Services, PNG(NE) reports under spending of $632,000 in 2016 and $890,000 in 2017 for FSJ/DC. PNG(NE) explains that the capital forecast for this item was based on previous years' activities for distribution service lines designed to meet the needs of new customers and all areas experienced a downturn in construction activity in both 2016 and 2017. Table 5 provides a comparison of the number of new distribution service lines forecasted for 2016 and 2017 against the actual number installed. Related to this are Distribution Mains which are installed to meet the needs of new growth that had directionally similar variances to forecast. Expenditures of $110,000 in 2016 and $179,000 in 2017 resulted in variances to forecast in this project category of $444,000 in 2016 and $386,000 in 2017 for FSJ/DC. PNG(NE) explains that these variances are due to the impact of the economic downturn in construction activity over 2016 and 2017. [57]

Table 5: Comparison of The Number of New Distribution Service Lines Forecast For 2016 And 2017 and The Actual Number of New Distribution Service Lines Installed In 2016 And 2017.[58]

FSJ/DC	2016 Forecast	2016 Actual	2017 Forecast	2017 Actual
New Distribution Service Lines	400	207	400	127

Offsetting under expenditures in New Services and Distribution Mains were over expenditures of $723,000 in 2016 and $1,137,000 in 2017 for Distribution Main Improvements-Other. PNG(NE) explains that the 2016 over expenditure resulted from unplanned line lowerings in the FSJ area and in 2017 its decision to accelerate electrofusion tee replacement activity due to its reassessment of the work as necessary to ensure system safety and reliability and reduce the level of risk.[59]

For 2018 and 2019, PNG(NE) is forecasting an increase in the number of New Services in the FSJ/DC service area, estimating capital expenditures of $848,957 and $1,021,938 for 2018 and 2019 based on 340 new services being installed in each of those years. These amounts, while lower than 2016 and 2017 forecasts, are substantially higher than actual 2016/2017 expenditures. PNG(NE) states that the 2016 and 2017 variances were considered as part of the forecasting process and adjustments were made accordingly. [60]

With respect to Distribution Mains providing service to new customers, PNG(NE) has forecast $445,000 for 2018 and $587,000 for 2019. These amounts are again substantially higher than 2016 and 2017 actual expenditures. PNG(NE) explains that growth continues in the region and the resultant economic development has created opportunities to provide natural gas to service the demand. Worthy of note is the Company's expectation of continued uncertainty in Northeastern BC's economy over the course of 2018 and 2019. PNG(NE) has stated that it expects both upwards and downwards pressures as a result of mining and commodity price increases as

[57] Exhibit B-1-1, FSJ/DC, pp. 83–88; PNG(NE) Final Reply Argument, p. 6.
[58] Exhibit B-9, BCUC IR 79.1.2.
[59] Exhibit B-1-1, FSJ/DC, p. 84; Exhibit B-5, BCUC IR 52.3.
[60] Exhibit B-1-1, FSJ/DC, pp. 61–67, Exhibit B-5, BCUC IR 37.1.

well as decreases due to softwood lumber tariff issues and stalled LNG projects, all of which lead to what it describes as an “uncertain economic outlook”.[61]

BCOAPO et al. raises concern over the New Services capital expenditures, noting that “the Total Actual New Services spending for both 2016 and 2017 added together is less than the Approved Spending for just 2016 by itself.” It further states that the 2016 actual was “barely 50%” of the forecast and the 2017 actual was less than 32 percent of the forecast.[62]

The BCOAPO et al. submits there:

> …is strong evidence of recent over-forecasting of the new services component of cap ex; as such new services forecast for the 2018 and 2019 Test Years should be reduced by at least 50% in both years, with appropriate adjustments made to the revenue requirement, revenue deficiency, and rates.[63]

PNG(NE) states that it is not possible for actual results to match forecast amounts and resulting variances will be either favourable or unfavourable to either ratepayers or the utility. PNG(NE) notes that focusing on New Services or other categories of under spending variances yet ignoring the significant over expenditures in Distribution Main Improvement-Other goes to its point that these favourable or unfavourable variances will be realized. PNG(NE) also notes that in four of the last five years it has been unable to achieve its allowed return which is evidence that the risk it undertakes “under its regulatory construct actually resulted in an under collection of rates.”[64]

BCUC determination

The Panel is not persuaded that PNG(NE) has adequately justified the need for its forecast amounts for recurring capital with particular reference to New Services and Distribution Mains. Looking back to 2016 and 2017, PNG(NE) has expended recurring capital in line with what it has forecast. However, this has occurred only because of an unplanned incident necessitating additional expenditures in the Distribution Main Improvement-Other category in 2016 and the decision made to advance a project into 2017 rather than scheduling it later. At the same time there have been large unspent capital amounts in New Services and Distribution Mains over this period which the Panel is not satisfied have been adequately addressed going forward into 2018 and 2019.

The Panel acknowledges that PNG(NE) has reduced its forecast for FSJ/DC for the number of new distribution service lines within this service area and its forecast expenditures. But, as noted these are still well above those in recent history and PNG(NE) has not provided sufficient supporting evidence to suggest that the economic conditions which have affected construction growth in FSJ/DC are expected to change in the near future. Given these circumstances, the Panel finds the forecast for 340 New Services in each of 2018 and 2019 to be overly optimistic and unrealistic. A review of PNG(NE)’s reported actuals for new services for the period 2013 to 2017 indicates that the average number of new services installed over the past five years was 291 and the most recent two year average was 167, as shown in Table 6.

[61] Exhibit B-5, BCUC IR 12.1.
[62] BCOAPO Final Argument, p. 8.
[63] BCOAPO Final Argument, p. 8.
[64] PNG(NE) Reply Argument, pp. 5–6; Exhibit B-9, BCUC IR 79.1.2.1.

Table 6: Number of New Services for 2013 to 2017 – Reported Actuals[65]

Year	New Services – Reported Actuals
2013	352
2014	385
2015	385
2016	207
2017	127
5-year Average	**291**
2-year Average	**167**

Based on recent history, and allowing for some improvement in growth prospects, the Panel finds that a forecast number of 230, which is based on the median of the five year and two year averages, is more reasonable and reflective of the uncertain economic outlook. **Therefore, the Panel rejects PNG(NE)'s forecast of 340 new services and directs PNG(NE) as part of its compliance filing to calculate and refile a capital expenditure amount for New Services based on the installation of 230 new service for each of 2018 and 2019.**

Similarly, the Panel finds that a reduction in the forecast amounts for Distribution Mains is warranted. PNG(NE) has provided no evidence to support the large increase in forecast expenditures nor has it outlined projects it plans to undertake. **Accordingly, the Panel rejects the forecast capital expenditures for Distribution Mains. The Panel directs PNG(NE), as part of its compliance filing, to refile an amount for this category reflecting no more than the average actual expenditure for Distribution Mains over the past three years with an inflation factor reflecting the BC CPI over this period.**

As for the balance of FSJ/DC and TR recurring projects, the Panel finds that PNG(NE) has provided sufficient evidence in support of the amounts forecast. Accordingly, the Panel accepts PNG(NE)'s filing of recurring capital expenditures, with the exception of those areas previously noted.

Planned - Non-recurring capital projects

PNG(NE)'s Planned – Non-recurring forecast capital expenditures for 2018 and 2019 are $4,221,363 and $2,612,652 respectively for FSJ/DC, with no Carry-forward projects moved from previous periods. This is a significant increase compared to the 2016 and 2017 actual expenditures of $1,292,294 and $273,958.

For TR, PNG(NE) is forecasting capital expenditures for 2018 and 2019 of $62,413 and $197,625, respectively, for Non-recurring capital projects, which are below the actual expenditures of $227,094 and $199,325 reported for 2016 and 2017, respectively. However, PNG(NE) does forecast capital expenditures of $900,000 for 2018 for the Transmission Line Repair project, which is a carry-forward project from 2017.

The major capital projects planned for FSJ/DC in 2018 and 2019 are listed in Table 7 and Table 8 below:

[65] PNG(NE) 2014 RRA FSJ/DC Division and TR Division, Exhibit B-5, BCUC IR 50.2; PNG(NE) 2016-2017 RRA FSJ/DC Division and TR Division, Exhibit B-5, BCUC IR 25.2; Exhibit B-9, BCUC IR 79.1.2 (Table created by BCUC).

Table 7: Test Year 2018 Capital Expenditures (FSJ/DC)[66]

2018 Major Capital Projects (> $50,000)	Budgeted Cost Excluding Overhead
Planned – Non-recurring	
North Pine Pipe Purchase – FSJ	$1,700,000
DC Gate #1 Station Replacement	$1,121,300
Cecil Lake Aluminium Replacement – FSJ	$282,423
Geotechnical Information System	$242,128
Min Repairs and Assessments	$235,855
Replace Line Heaters	$222,988
Steel Main Replacement – DC	$158,245
Underground Fitting Removal – DC	$140,054
Other Minor Projects <$50,000	$118,371
Subtotal	**$4,221,363**

Table 8: Test Year 2019 Capital Expenditures (FSJ/DC)[67]

2019 Major Capital Projects (> $50,000)	Budgeted Cost Excluding Overhead
Planned – Non-recurring	
Cecil Lake Aluminium Replacement – FSJ	$1,065,402
Geotechnical Information System	$376,860
Main Repairs and Assessments	$287,465
Station Modifications	$166,629
Steel Main Replacement – DC	$156,068
Baldonnel Line Lowering – Phase 1 – FSJ	$140,814
Underground Fitting Removal - DC	$140,001
Block Valve Installation - DC	$103,534
Structure Improvements	$95,880
Pennwest Pipeline Replacement FEED Study	$80,000
No Other Minor Projects <$50,000	$-
Subtotal	**$2,612,652**

[66] Exhibit B-1-1, FSJ/DC, p. 61 (Table created by BCUC).
[67] Ibid., p. 66 (Table created by BCUC).

BCUC determination

The Panel notes that the North Pine Pipeline project with capital expenditures of $1.7 million was the subject of a separate CPCN application and therefore will not be addressed within these Reasons for Decision. By Order G-136-18 dated July 20, 2018 the BCUC denied PNG(NE)'s application for a CPCN to own and operate the North Pine pipeline project. **Accordingly, PNG(NE) is directed to remove the capital expenditures related to the North Pine pipeline project from its 2018 and 2019 revenue requirements in its compliance filing made pursuant to directive 17 of the order accompanying these reasons.** Of the remaining projects listed in Table 7 and Table 8 for the FSJ/DC division, specific concerns arose with respect to the Cecil Lake Aluminum Replacement and the Baldonnel Line Lowering project which are addressed below. As for the balance of non-recurring projects, the Panel finds that PNG(NE) has provided sufficient evidence justifying the need for these projects, many of which involve replacement of aged facilities and replacement of equipment to ensure safe and reliable operations are maintained.

Accordingly, the Panel accepts PNG(NE)'s filing of capital expenditures, subject to the removal of expenditures relating to the North Pine Pipeline project, adjustments identified in the IR process and any further directives concerning specific projects made within these Reasons for Decision. **The incorporation of the capital expenditures into rates is approved upon completion of the projects, subject to any prudency review of expenditures that may arise**.

Cecil Lake Aluminum Replacement Project (FSJ/DC)

The Cecil Lake Aluminum Replacement project is to replace the aluminum pipeline infrastructure in the Cecil Lake area and capital expenditures for 2018 and 2019 are estimated at $282,423 and $1,065,402 respectively. PNG(NE) states that aluminum natural gas pipelines are no longer commonly used and can pose an integrity risk. Furthermore, PNG(NE) explains that it does not have the in-house training or tooling to respond to and repair emergency events related to aluminum pipelines and the last remaining contractor in the PNG(NE) service area has elected to no longer maintain the required certifications. Therefore, an emergency event could result in a state of non-conformance with maintenance, repair and integrity management aspects of CSA Z662 and consequently subject employees and the general public to risk above tolerable levels.[68]

PNG(NE) elaborates on the scope and timelines of the project, indicating that the project will span beyond 2019, stating that:

> In order to complete the full scope of the multi-year program, additional phases of the Cecil Lake Aluminum Replacement project will extend beyond 2019. Replacement of the 15.5km of pipeline is anticipated to take place across an additional 2-3 years beyond 2019 at a projected cost of $1.5-$2 million annually.[69]

BCUC determination

The Panel accepts there is a need for the Cecil Lake Aluminum Replacement project in order to provide safe and reliable service while maintaining conformance with CSA standards. **Accordingly, the Panel accepts PNG(NE)'s filing of capital expenditures of $1,347,825 for the Cecil Lake Aluminum Replacement project. The incorporation of the project costs into rates is approved upon completion of the project, subject to any prudency review of expenditures that may arise.**

[68] Exhibit B-9, BCUC IR 82.1; PNG(NE) Final Argument, p. 21.
[69] Exhibit B-14, Panel IR No. 2 1.1.

The Panel notes that PNG(NE) anticipates the project to continue for 2–3 years beyond 2019, at an additional cost of $1.5 to $2 million annually which could place the total project cost at $7.3 million, a significant capital expenditure for the FSJ/DC division. This was not apparent until the Panel IR which followed the regulatory process. Given the magnitude of the total capital expenditures for this project, this information should have been provided at a much earlier date. In the future, the Panel expects PNG(NE) to be more forthcoming and transparent with respect to details regarding ongoing capital projects which cover more than one test period. **Accordingly, for future RRAs, in addition to information provided for the test period, PNG(NE) is directed to provide the total project costs by year for any capital projects that span beyond the test period, rather than dividing the project into small pieces and reporting on only the capital expenditures as they impact a particular test period**.

Baldonnel Line Lowering (FSJ/DC)

PNG(NE) reports that a privately-owned sewage lagoon located immediately adjacent to PNG(NE)'s right of way has breached on several occasions, resulting in the super saturation of soils supporting its high-pressure pipeline. The geotechnical failures have the potential to impact the pipeline and result in integrity concerns. As such, PNG(NE) proposes to lower the pipeline to a depth that will render the lagoon as no risk and also minimize the risk of geological failure.[70]

PNG(NE) forecasts capital expenditure of $141,000 for Phase 1 of the project in 2019. Phase 1 of the project includes all work required to develop a technical design, geotechnical review, geotechnical drilling, fish habitat assessments, regulatory requirements and permitting. Phase 2 of the project is for construction which is scheduled for 2020. The total capital costs for the project are to be determined following the completion of frontend engineering, development of lowering and relocation options, and development of the associated cost estimates.[71]

In April 2018 PNG(NE) requested that the Ministry of Environment (MOE), the permitting body for the lagoon, "cause the permit holder to cease discharging effluent in the lower 3rd of the coulee slope which significantly contributes to the already noted geotechnical issues."[72] PNG(NE) further explains:

> PNG(NE) has determined that the best course of action to ensure the integrity of the pipeline and the security of gas supply is to relocate the pipeline away from the ongoing threat from the lagoon discharge and the present geotechnical risk.[73]

PNG(NE) states that it deems a horizontal direction drill in the existing pipeline location, which is within its existing rights of way, to be the most likely and feasible remediation option. However, CN Rail permitting for access, landowner permissions, British Columbia Oil and Gas Commission permitting and Enbridge proximity permitting will all be required.[74]

BCUC determination

The Panel is persuaded that PNG(NE)'s concerns regarding the integrity of the high-pressure pipeline and the geotechnical risk justifies the need for the first phase of the project. **Therefore, the Panel accepts the capital expenditures of $140,814 in 2019 for Phase 1 of the Baldonnel Line Lowering project.**

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[70] Exhibit B-1-1, FSJ/DC, pp. 66 & 69; Exhibit B-5, BCUC IR 44.1; Exhibit B-9, BCUC IR 91.2.
[71] Exhibit B-1-1, FSJ/DC, pp. 66 & 69; Exhibit B-5, BCUC IR 44.2.
[72] Exhibit B-9, BCUC IR 91.1.
[73] Ibid., BCUC IR 91.1.
[74] Exhibit B-9, BCUC IR 91.2, 91.3.

However, the Panel notes that the exacerbation of the geotechnical conditions is caused by a privately-owned sewage lagoon which has the potential to impact the pipeline and therefore, PNG(NE)'s ability to ensure the security of supply to its customers. The Panel also notes that PNG(NE)'s preferred option for remediation requires the attainment of permits and permissions from the various external parties identified. Perhaps more importantly, the total project costs are yet to be determined. Given these circumstances the Panel finds that the public interest is best served by a more comprehensive review of this project going forward. **Therefore, in accordance with section 45(5) of the UCA, PNG(NE) is directed to file a CPCN application for this project prior proceeding with Phase 2 of the project and construction.**

5.0 Deferral Accounts

5.1 Amortization of Legacy Deferred Income Taxes deferral account

PNG(NE) requests approval to fully amortize the remaining balance of the Tumbler Ridge Legacy Deferred Income Taxes deferral account in 2018, which amounts to $106,000 including accrued interest, and eliminate the account once the balance is fully amortized. The deferral account earns interest at PNG(NE)'s weighted average cost of debt (WACD) and records the legacy Tumbler Ridge deferred income tax balances. By Order G-89-13 the BCUC directed PNG(NE) to amortize a portion over 6 years and by Order G-131-13 the BCUC directed PNG(NE) to amortize the remaining balance over 7 years.[75] Accordingly, in the absence of PNG(NE)'s proposal in the current proceeding, the deferral account balance would be fully amortized by the end of 2020.[76] PNG(NE) states that it has made the request to fully amortize the remaining balance in 2018 in order to help mitigate the impact of the significant increase in its cost of service.[77] The proposal results in a higher delivery rate decrease in 2018 of 8.5 percent.[78]

BCUC Determination

The Panel approves PNG(NE)'s request to fully amortize the balance of the Legacy Deferred Income Taxes deferral account in 2018 and then eliminate the account. The Panel agrees with PNG(NE) that this is a reasonable request to mitigate cost of service increases in 2018.

6.0 Other matters

6.1 Capital structure and rate of return

The allowed return on equity (ROE) and common equity for the PNG(NE) FSJ/DC and TR divisions were established in the BCUC Generic Cost of Capital Stage 2 proceeding, effective January 1, 2013, by Order G-47-14 and Decision dated March 25, 2014. PNG(NE) FSJ/DC and TR were measured against the FortisBC Energy Inc. (FEI) benchmark utility. The FEI benchmark utility's allowed ROE is 8.75% and the common equity component is 38.5%. For PNG(NE) FSJ/DC, the allowed ROE is 9.25% (50 basis points above the benchmark) and the common equity component is 41.0%. For PNG(NE) TR, the allowed ROE is 9.5% (75 basis points above the benchmark) and the common equity component is 46.5%.

[75] Exhibit B-1-1, TR, p. 50.
[76] Exhibit B-3, BCUC IR 24.1.
[77] Exhibit B-1-1, TR, p. 50.
[78] Exhibit B-3, BCUC IR 24.2.

In its March 25, 2014 Decision, the BCUC acknowledged that the PNG utilities face a unique set of circumstances with respect to the level of business risk. The BCUC viewed that it was important to ensure that PNG's business risk assessment remains contemporary and its cost of capital is aligned with it. The PNG utilities were directed to include an updated business risk assessment in all future RRAs[79].

As part of the Application, PNG(NE) filed a consolidated business risk assessment update for 2018 for all divisions as it considered that they face similar risks[80]. PNG considers that its business risks for each of its entities have been trending higher since 2012 (i.e. lack of LNG and mining industries, climate change policies, electrification policies, and gas supply risks). However, PNG(NE) does not propose any changes to its capital structure and ROE as the change has not been overly substantive at this time[81].

In response to information requests (IR), PNG(NE) filed DBRS credit rating reports for 2015, 2016 and 2017 on a confidential basis, which cover all three divisions on a consolidated basis. PNG's credit rating remains the same at BBB(low) over the last five years[82]. Furthermore, PNG(NE) submits that natural gas commodity prices continue to be lower than 2012 and 2016 and have been less volatile in recent years[83].

Panel discussion

The Panel acknowledges that PNG(NE) has filed the 2018 update of its business risk assessment in compliance with Order G-47-14, and that PNG(NE) is not seeking any changes to its allowed ROE and capital structure for the FSJ/DC and TR divisions at this time. Based on the evidence presented, the Panel agrees there is no immediate need for a change to allowed ROE or the current equity component as the overall risk profile has not changed substantially. As market conditions and utility business environment change, the appropriateness of the utility's cost of capital should be reviewed as part of the rate setting process. Therefore, the Panel expects that PNG(NE) will continue to include an updated business risk assessment in all future RRAs, as directed in Order G-47-14.

6.2 Potential Rate Harmonization

Based on the implementation of its proposed rate deferral mechanism, PNG(NE) has calculated a revenue deficiency for TR of $206,000 for 2018 and $230,000 for 2019. PNG(NE) attributes this revenue deficiency primarily to lower forecast deliveries to its only commercial customer, Canadian Natural Resources (CNRL). This results in a residential rate increase of 19.1 percent and 18.1 percent respectively for these years or in terms of actual rates, a delivery rate increase of approximately $98 per year for the average residential customer in 2018 and $113 in 2019. Commercial rate increases are directionally similar to that forecast for residential customers. Of concern to the Panel is that these delivery rate increases are significant and, if they were to coincide with a material increase in gas commodity costs, have the potential to create what is commonly referred to as "rate shock".[84]

Table 9 outlines forecast gas deliveries for test years 2018 and 2019 and lists historical deliveries going back to 2013. This Table indicates a sharp drop in CNRL industrial transport deliveries in 2016 continuing into 2017, a trend that is forecast to continue through 2018 and 2019. PNG(NE) reports that its discussions with CNRL have

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[79] BCUC Generic Cost of Capital Proceeding (Stage 2), Decision and Order G-47-14 dated March 25, 2014, p. 114.
[80] Exhibit B-1-1, FSJ/DC Appendix F, p. 1 and TR Appendix E, p. 1.
[81] Exhibit B-1-1, FSJ/DC Appendix F, p. 6 and TR Appendix E, p. 6.
[82] Exhibit B-5, BCUC IR 49.1.
[83] ibid., BCUC IR 50.2; Exhibit B-9, BCUC IR 93.0.
[84] Exhibit B-1-1, TR, p. 6; Exhibit B-3, BCUC 2.1.

confirmed that the reduced deliveries are related to the shut-down of their low pressure wells due to the current low-commodity price environment.[85]

Table 9: Forecast Gas Deliveries[86]

Customer Classification	Test Year 2019 Deliveries	2019 to 2018 Change in Forecast Deliveries	2019 to 2018 Change in Forecast Margin	Test Year 2018 Deliveries	2018 to 2017 Change in Forecast Deliveries	2018 to 2017 Change in Forecast Margin	Decision 2017 Deliveries	Actual 2017 Deliveries	Actual 2016 Deliveries	Actual 2015 Deliveries	Actual 2014 Deliveries	Actual 2013 Deliveries
	GJ	GJ	$	GJ	GJ	$	GJ					
Residential	80,063	(958)	(8,100)	81,021	(2,135)	(14,408)	83,156	84,503	70,939	78,755	96,784	81,534
Commercial												
Small Commercial Firm (Rate 2)	35,156	(1,068)	(7,300)	36,224	(2,189)	(13,052)	38,413	35,659	33,942	34,627	44,907	47,937
Large Commercial Firm (Rate 3)	16,000	-	-	16,000	3,000	14,522	13,000	18,446	11,650	16,931	58,278	74,711
Total Commercial	51,156	(1,068)	(7,300)	52,224	811	1,470	51,413	54,105	45,592	51,558	103,185	122,648
Industrial Transport (CNRL)	450,000	-	-	450,000	(365,000)	(153,366)	815,000	463,093	596,334	815,142	628,584	602,495
Total	581,219	(2,026)	(15,400)	583,245	(366,324)	(166,304)	949,569	601,701	712,865	945,455	828,553	806,677

Table 10 provides the forecast for residential customer count and use per account (UPA) and a historical view going back to 2008. While the customer count has remained stable and increased slightly over the years, the use per customer has dropped significantly. PNG(NE) provides no insight as to whether this is due to weather factors or whether the use of alternative fuels is behind this reduced usage. However, if it is determined that the use of a lower cost alternative fuel is a factor, it is likely a trend that worsens as natural gas prices rise.

Table 10: Forecast Residential Customer Count and UPA[87]

	Forecast			Actual										
Residential Customers - TR	Test Year 2019	Test Year 2018	Decision 2017	2017	2016	2015	2014	2013	2012	2011	2010	2009	2008
Customer Count at Year End	1,138	1,140	1,127	1,139	1,141	1,137	1,149	1,151	1,109	1,092	1,084	1,077	1,073
Normalized Use per Account (GJ)	70.3	71.2	73.7	74.3	68.5	74.2	77.7	81.8	82.9	87.7	80.3	81.6	83.1

The BCUC raised this issue in a number of Tumbler Ridge information requests (BCUC IR 2.1, 2.2 and 2.3). In response PNG(NE) noted it is cognizant of the significant size of its proposed delivery increases and acknowledges that it could constitute rate shock for some of its customers, especially those of low-income households. That said, PNG(NE) further explains that when these increases are coupled with a proposed decrease of both the RSAM rate riders and commodity costs, the impact on customers is reduced. When these factors are taken into account, the average residential customer would face an annual total bill decrease of $45 in 2018 followed by an increase of $145 in 2019.[88] In consideration of the small number of customers and the downturn in the region's economy, PNG(NE) states it has tried to keep operating costs down and delayed non-critical capital work and, in addition, has explored other sources of gas supply to potentially lower costs for its customers. In conclusion, the company states that it does not see an alternative to its proposed rate increases but concedes it does plan to explore rate design alternatives in the future to help mitigate delivery rate increases.[89]

PNG(NE) was also queried as to whether it had considered rate design alternatives to the current structure between divisions of PNG(NE) or with PNG-West as a means of mitigating rate volatility with specific reference

[85] Exhibit B-1-1, TR, p.24.
[86] Ibid., p.23.
[87] Ibid., p.24.
[88] Ibid. Tab 6, p. 2 and 13. In its response to BCUC IR 2.1 (Exhibit B-3) PNG(NE) provides the total 2019 residential bill increase as $128; however, the source for the information is Exhibit B-1-1, TR, Tab 6, p. 13, which includes an amount of $145.
[89] Exhibit B-3, BCUC IR 2.1 and 2.2.

to postage-stamp rates and amalgamation. In response PNG(NE) notes that it has considered options for amalgamating its divisions in a manner that could result in postage stamp rates. However, the company also points out that TR's lack of connection to the Westcoast transmission system and the costs related to both the TR gas processing plant and the 35 kilometer transmission pipeline which must be borne by its ratepayers are unique factors among PNG divisions.

More specifically, an option for amalgamation that has been considered is the recovery of TR processing and transmission costs from all customers of PNG (NE) divisions. This would reduce TR costs at the expense of those from FSJ/DC but with no additional benefit to the latter communities. However, PNG(NE) states it has not identified a reasoned basis grounded in cost causation and recovery principles that supports proceeding with the amalgamation of its divisions.

PNG(NE) notes the similarity between TR customers and those customers connected to a propane system in Granisle stating:

> For both these isolated systems, customers' rates and energy supply costs do reflect the cost of providing reliable energy supply to small load centres located remote from sources of marketable gas supply.
>
> PNG also notes that for both of these remote communities the cost of energy delivered is still significantly lower than for electricity.[90]

BCOAPO et al., noting a cumulative residential delivery rate increase of 40.65 percent for TR over two years, states that this will result in annual bill increases of $97 in 2018 (based on average consumption of 70.2 GJ) and $108 in 2019 (based on average consumption of 70.3 GJ). Such increases are a concern to BCOAPO et al. which represents what it describes as British Columbia's most economically vulnerable ratepayers and submits it is incumbent upon PNG(NE) to mitigate these costs through effective cost controls and proposals to smooth rates.[91]

Panel discussion

With reference to the current Application, PNG(NE) has explained that when the proposed decrease to both the RSAM rate riders and commodity costs are taken into account, the net impact in terms of 2018 and 2019 rates is more moderate than what is suggested by consideration of the revenue requirements alone. However, while the current circumstances have served to moderate the impacts of increased revenue requirements and possibly BCOAPO et al.'s short-term concerns, it is not reasonable to assume that this reprieve will continue into the future. Given its size, its less stable regional economy and the infrastructure required to sustain service, the community of TR is and will continue to be, more susceptible to greater rate volatility than other PNG divisions. The question is how this is best managed going forward.

The Panel notes that we will likely continue to be in a period of generally stable natural gas pricing. If this were to change and there were a significant increase in the cost of gas, it would have a severe impact on TR customer rates. This could result in some of the TR existing customer base switching to alternative fuels leading to an even bigger impact on delivery rates for those where fuel switching is not a viable option. There is some evidence to suggest that this may already be occurring as Table 10 indicates that the TR natural gas use per customer has dropped significantly since 2013.

[90] ibid., BCUC IR 2.2.
[91] BCOAPO Final Argument, p. 3.

The Panel encourages PNG(NE) to consider options to the current rate design and notes that harmonization of rates among its various divisions would be in keeping with historic government support for postage stamp rates. Consideration of alternative rate designs such as postage stamp rates would also offer some potential advantages. For one it could help create greater stability of rates within the PNG(NE) divisions and potentially forestall any fuel switching which may be currently occurring within TR resulting in better usage of existing assets and reduce the risk of stranded assets. Also, depending upon the approach taken, there would be potential for regulatory savings related to reduced preparation and adjudication of multiple RRAs. As a consequence, regulatory costs could be reduced and the time saved allocated to other activities which is a benefit to all PNG(NE)ratepayers.