bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

Pacific Northern Gas Ltd.

2020–2021 Revenue Requirements Application

for the West Division

Decision
and Order G-255-20

October 14, 2020

Before:
A. K. Fung, QC, Panel Chair
C. Brewer, Commissioner
M. Kresivo, QC, Commissioner

TABLE OF CONTENTS

Page no.

Executive summary

PNG owns and operates a natural gas transmission and distribution system located in the west central part of British Columbia and is a wholly owned subsidiary of TriSummit Utilities Inc. PNG serves approximately 20,400 natural gas customers with an additional 130 propane customers in Granisle, BC.

On February 28, 2020, PNG filed its 2020-2021 RRA requesting approval of permanent 2020 and 2021 delivery rates for all rate classes, a permanent RSAM rate rider of $1.175/GJ and $0.359/GJ effective January 1, 2020 and January 1, 2021, respectively, in addition to other approvals sought. The permanent 2020 and 2021 delivery rates contained in the Application include the following:

Rate Class	2020 Delivery Rate	2021 Delivery Rate
Residential	$12.374/GJ	$12.655/GJ
Small Commercial	$10.417/GJ	$10.643/GJ
Granisle Propane	$7.086/GJ	$7.283/GJ

The Panel established a written public hearing process, in which 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 participated as the sole intervener.

PNG applied for several adjustments to its 2020 and 2021 delivery rates during the regulatory process, which are summarized in PNG's final argument[1] and Appendix A of this decision. This includes PNG's request for approval to smooth delivery rate increases over the two years, resulting in an average increase of approximately 2.0 percent in 2020 and approximately 1.9 percent in 2021. This is achieved in part by making the following interim 2020 delivery rates approved by Order G-330-19A permanent:

Rate Class	Interim Delivery Rate Effective January 1, 2020
Residential	$12.377/GJ
Small Commercial	$10.420/GJ
Granisle Propane	$7.090/GJ

There are several factors that contribute to increases to PNG's 2020 and 2021 costs that were identified during the public hearing, including pipeline integrity management activities, IT project costs and full recovery of the shared corporate services cost allocation from PNG's parent company, TSU. After a review of the evidence and argument, the Panel found the costs associated with these items in 2020 and 2021 to be reasonable. The Panel

[1] PNG-West Supplemental Final Argument (July 2, 2020), p. 4.

approves the 2020 and 2021 delivery rates and RSAM rate rider filed in the Application on a permanent basis, subject to the adjustments identified by PNG during the regulatory process and summarized in Appendix A to the decision approving the permanent delivery rates and to the directives and determinations in this decision. This includes approval to make the interim delivery rates approved by Order G-330-19A permanent, effective January 1, 2020. In addition, PNG is directed to file annually a report on significant capital expenditures by April 30 and to provide specific items in its next RRA, including information regarding pipeline integrity management activities and details of any cost savings associated with various IT projects.

1.0 Introduction

1.1 Nature of the Application

The purpose of this proceeding is to review the 2020-2021 revenue requirements application (RRA) Pacific Northern Gas Ltd. (PNG) filed on behalf of its western division, PNG-West, for approval by the British Columbia Utilities Commission (BCUC) pursuant to sections 58 to 61 of the *Utilities Commission Act* (UCA). In a separate but related proceeding, the Panel reviews the RRA brought by PNG's subsidiary, Pacific Northern Gas (N.E.) Ltd. (PNG(NE)), for the same period.

For purposes of clarity the term "PNG" will be used when referring to general corporate direction while the term "PNG-West" will be used with reference to requests for approval made during the proceeding and any operational and non-corporate issues related to this division.

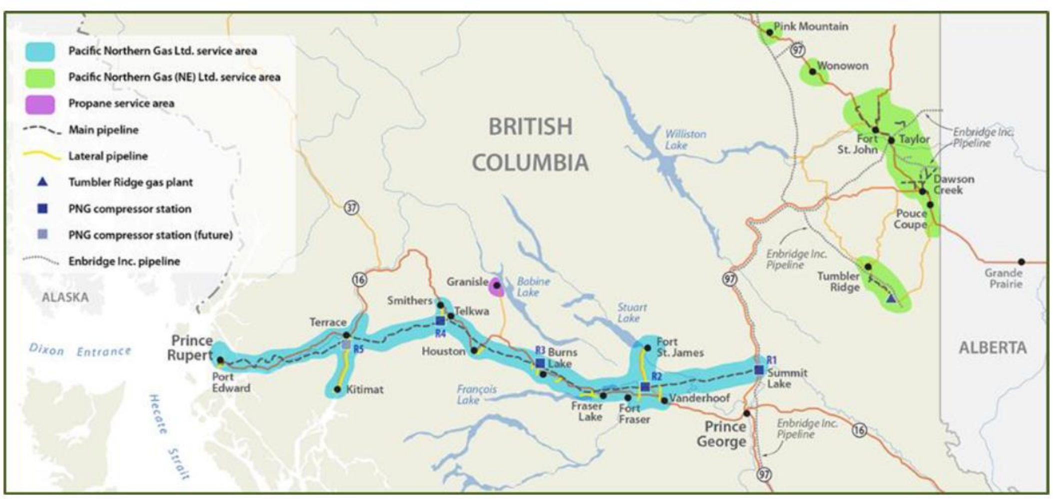
1.2 Background

PNG-West owns and operates 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 Prince Rupert and Kitimat. Along this corridor PNG-West serves some 20,400 natural gas customers with an additional 130 propane customers in Granisle, BC.[2]

PNG(NE) operates a gas processing plant and natural gas distribution system providing service to some 21,500 natural gas customers in three different but connected service territories: Fort St John (FSJ); Dawson Creek (DC); and Tumbler Ridge (TR).

The PNG-West and PNG(NE) natural gas pipeline systems are illustrated in Figure 1.[3]

Figure 1: PNG System Map -PNG-West and PNG(NE)



[2] Exhibit B-2, Section 1.1, p. 2.
[3] Exhibit B-2, p. 3.

PNG-West's 2020-2021 RRA filed on November 29, 2019 seeks approval to amend its delivery rates and Revenue Stabilization Adjustment Mechanism (RSAM) on an interim and refundable/recoverable basis, effective January 1, 2020 (Original Application). PNG-West's fiscal years 2020 and 2021 are referred to as the "Test Period."

By Order G-330-19A, the Panel, among other things, approved interim delivery rates of $12.377/GJ for residential service and $10.420/GJ for small commercial service and $7.090/GJ for Granisle propane service. The Panel also approved an increase in the RSAM rate rider from a credit of $0.327/GJ to a debit of $1.095/GJ. These interim approvals were effective January 1, 2020.

On February 28, 2020, PNG-West filed an amended application to support its request for approval of rates on a permanent basis. The amended application includes all of the information of the Original Application and revisions such as amended demand forecasts which take into consideration the effects of 2019 actual deliveries, updated customer count and cost forecasts, as well as the impact of 2019 actual operating results on rate-base items.[4] From this point forward, the "Application" refers to PNG-West's amended application.

In December 2011, AltaGas Utility Holdings (Pacific) Inc., a 100 percent owned subsidiary of AltaGas Ltd. (AltaGas) acquired PNG. In late 2018, AltaGas undertook a corporate reorganization that resulted in the (i) renaming of AltaGas Utility Holdings (Pacific) Inc. to AltaGas Canada Inc. (ACI); (ii) amalgamation of AltaGas' Canadian utilities and renewables power infrastructure into ACI; and (iii) establishment of ACI as a new standalone public company.[5] On March 31, 2020, the Public Sector Pension Investment Board (PSPIB) and the Alberta Teachers' Retirement Fund Board (ATRFB) completed the purchase of all issued and outstanding common shares of ACI,[6] and ACI's name was changed to TriSummit Utilities Inc. (TSU).[7]

1.3 Regulatory Process and Participants

By Order G-330-19A, the BCUC established a regulatory timetable and a written public hearing process for the review of the Application. The timetable included intervener registration, an amended application, two rounds of BCUC and intervener information requests (IR), and responses to IRs.

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) registered as the sole intervener. Two interested parties also registered, and four letters of comment were received.

On April 27, 2020, the BCUC established the remainder of the regulatory process, which included written final and reply arguments.[8] This was subsequently amended at the request of PNG-West.[9]

By letter dated June 2, 2020, the Panel issued Panel IR No. 1 requesting additional information and further clarification on the Salvus to Galloway remediation project and the outcome of the Reactivated Capacity Allocation Process (RECAP).

---

[4] Exhibit B-2, p. 1.
[5] Ibid., Section 1.1, p. 2.
[6] TSU Press Release dated December 19, 2010 (https://trisummit.ca/index.php/newsroom/news-2019/217-ltaasanadanchareholdersspproverrangementnvolv20191219134200)
[7] TSU Fiscal 2020 Second Quarterly Report, Management's Discussion and Analysis, The Company, p. 2 (https://trisummit.ca/images/pdf/TSU_Q2_2020_Combined_Doc_MDAFS_FINAL.pdf)
[8] Order G-95-20.
[9] Order G-116-20.

On June 16, 2020, PNG-West filed an evidentiary update addressing two errors that pertain to the modelling of certain IT-related capital additions and income tax deductions and that also impact rates in the Test Period. Following a review of the evidentiary update, the BCUC re-opened the evidentiary record and amended the regulatory timetable to include BCUC and intervener IRs on the evidentiary update, PNG-West's response to the IRs, and revisions to the dates for written intervener final and PNG-West reply argument.[10]

Following PNG-West's filing of its Reply Argument, on July 31, 2020, the Panel re-opened the evidentiary record to issue Panel IR No. 2 regarding the Shared Corporate Services Costs. The BCUC amended the regulatory timetable and requested written supplementary final and reply arguments from the parties on the matters arising from Panel IR No. 2.

1.4 Approvals Sought

PNG-West included its approvals sought on pages 10-11 of the Application and subsequently identified several adjustments to its 2020-2021 revenue requirements and resulting delivery rates during the regulatory process, which are summarized in PNG-West's Final Argument[11] and Appendix A to this decision. PNG-West summarizes the final approvals sought in its Final Argument and Supplemental Final Argument dated July 2, 2020 as follows:[12]

1. Approval on a permanent basis, effective January 1, 2020, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, amongst others:[13]

    - A $0.276/GJ (2.3 percent) increase from $12.098/GJ to $12.374/GJ for Residential service;
    - A $0.219/GJ (2.1 percent) increase from $10.198/GJ to $10.417/GJ for Small Commercial service; and
    - A $0.193/GJ (2.8 percent) increase from $6.893/GJ to $7.086/GJ for Granisle Propane service.

    PNG-West is also seeking approval, effective January 1, 2020, to increase the RSAM rate rider applicable to Residential, Small Commercial and Commercial Transport customers on a permanent basis from a credit of $0.327/GJ to a debit of $1.175/GJ.[14]

    A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG-West division is provided in Appendix B of the Application.

    PNG-West proposes in its Supplemental Final Argument to have interim 2020 delivery rates as approved by Order G-330-19A made permanent.

2. Approval on a permanent basis, effective January 1, 2021, for the recovery of the applied for revenue deficiency and the resultant delivery rate changes to the following rate classes, among other rate classes:[15]

[10] Order G-158-20.
[11] PNG-West Supplemental Final Argument (July 2, 2020), p. 4.
[12] PNG-West Final Argument, Section 3, pp. 4-6; PNG-West Supplemental Final Argument (July 2, 2020), Section 2.1, p. 3.
[13] Exhibit B-2, Section 1.4, p. 8, Table 2; Tab 6, p. 6.
[14] Ibid., Tab 6, pp. 1-4.
[15] Exhibit B-2, Section 1.4, p. 8, Table 2; Tab 6, p. 22.

- A $0.281/GJ (2.3 percent) increase from $12.374/GJ to $12.655/GJ for Residential service;
- A $0.226/GJ (2.2 percent) increase from $10.417/GJ to $10.643/GJ for Small Commercial service; and
- A $0.197/GJ (2.8 percent) increase from $7.086/GJ to $7.283/GJ for Granisle Propane service.

PNG-West is also seeking approval, effective January 1, 2021, for a reduction in the RSAM rate rider on a permanent basis for PNG-West applicable to Residential, Small Commercial and Commercial Transport customers from a debit of $1.75/GJ to a debit of $0.359/GJ.[16]

A summary of the revenue deficiencies and resultant delivery rate changes for all rate classes for the PNG-West Division is provided in Appendix B.

3. Approval of the following changes and additions to deferral accounts and amortization expenses for 2020 and 2021:[17]

   a) Approval to amortize a portion of the LNG Partners Option Fee Payment deferral account in 2021 to mitigate rate impacts on customer rates; [18]
   b) Approval of a short-term interest bearing rate deferral account in 2020 to levelize the impact of the combined net revenue deficiencies for 2020 and 2021 to be fully amortized in 2021;[19]
   c) Approval to create the Accelerated Capital Cost Allowance (CCA) deferral account to record the impact of taking accelerated CCA in 2019 and amortizing this to the benefit of customers in test year 2020, as well as the subsequent dissolution of this account after test year 2021;[20]
   d) Approval to eliminate the Triton Liquefied Natural Gas (PLP) Project Amendment Sharing deferral account;[21] and
   e) Approval to record additions to the existing Reactivated Capacity Allocation Process Development Cost rate base deferral account in 2020 and 2021.[22]

4. Approval to create a new interest bearing deferral account to record the portion of Shared Corporate Services Costs not recovered in customer rates in test year 2020 or 2021, to be amortized at a future date subject to BCUC approval.[23]

5. Approval to re-instate a one-year interest bearing Transfer Pricing deferral account to track differences between forecast and actual utility charges to non-regulated services or activities.[24]

[16] Ibid., Tab 6, pp. 17-20.
[17] Ibid., Section 2.9, pp. 73-79; Tab 2, pp. 7-11.
[18] Exhibit B-2, Section 1.3, p. 7; PNG-West Final Argument, Section 6, pp. 9-10; PNG-West Supplemental Final Argument (July 2, 2020), Section 2.1, p. 3.
[19] PNG-West Supplemental Final Argument (July 02, 2020), Section 2.1, p. 3.
[20] Exhibit B-2, Section 2.9, pp. 76-77.
[21] Ibid., Section 2.9 pp. 78-79.
[22] PNG-West Supplemental Final Argument (July 2, 2020), Section 2.2, p. 3
[23] Ibid., Section 2.5.7.1, p. 63.
[24] Ibid., Section 2.5.7.2, pp. 65-66.

6. Approval to continue the unaccounted for gas (UAF) volume deferral account. PNG-West also requests approval to increase both the UAF component of Company Use gas from 0.0 to 1.0 percent and the UAF Volume deferral account loss cap from 1.0 to 1.5 percent.[25]

7. Approval to capitalize costs pertaining to magnetic flux leakage (MFL) in line inspection (ILI) runs to BCUC Account 469 on the basis that they are similar to inspection activities of electro-magnetic acoustic transducer (EMAT) ILI runs, and accordingly should have the same accounting treatment.[26]

8. Approval of the capital reporting process proposed by PNG-West in response to directive 5 of BCUC Order G-151-18.[27] The capital reporting process is applicable to PNG-West and PNG(NE).

9. Approval of the automotive cost allocation methodology proposed by PNG-West in response to a directive as per Section 3.0 of the BCUC's reasons for decision accompanying Order G-164-18A in PNG(NE)'s 2018-2019 RRA.[28] The automotive cost allocation methodology is applicable to PNG-West and PNG(NE).

1.5 Decision Framework

In this decision, the Panel specifically addresses the following:

Section 2.0 discusses two key drivers of cost increases over the Test Period: IT project expenditures and pipeline system integrity management;

Section 3.0 addresses issues related to the cost of service including those associated with operating, maintenance, administrative and general expenses, including the Shared Corporate Services Costs, Automotive Cost Allocation methodology and the forecast interest rates applied to short term and long term debt during the Test Period;

Section 4.0 deals with issues related to rate base, including capital expenditures, and reporting on significant capital projects;

Section 5.0 examines issues related to deferral accounts including handling of UAF Gas Losses, the Transfer Pricing deferral account, the Accelerated CCA deferral account, the PLP Project Amendment Sharing deferral account, and the RECAP deferral account; and

Section 6.0 addresses other matters, including the rate smoothing proposal, impact of the COVID-19 pandemic and PNG-West and PNG(NE) rate design.

2.0 Key Drivers of Cost Increases

The following sections address IT projects and pipeline system integrity management, which are two specific factors common to both PNG-West and PNG(NE) divisions that contribute to the increase in capital expenditures and operating and administrative expenses during the Test Period.

---

[25] Ibid., Section 2.2.3, pp. 29-33; PNG-West Final Argument, Section 16.1, pp. 32-33.
[26] PNG-West Final Argument, Section 15.1.1.2, pp. 12-13, 27-28.
[27] Exhibit B-2, Section 3.4.1.1, pp. 152-156; PNG-West Final Argument, Section 16.2, pp. 33-34.
[28] Ibid., Section 3.4.1.7, pp. 169-174; Ibid., Section 16.3, pp. 34-35.

2.1 IT Projects

Several new IT projects are driving increased capital expenditures and operating and administrative expenses for the Test Period, including a new accounting system, JD Edwards (JDE) Enterprise Resource Planning (ERP); payroll system, Ultimate Software (UltiPro) Human Resource Information System (HRIS); and customer information services (CIS) system. PNG proposes to allocate IT project costs to PNG-West and the PNG(NE) divisions using specific allocators for each IT project from the cost allocation methodology approved by the BCUC in Order G-114-13, including the composite average allocator, employee count and customer count allocators. The composite average allocator comprises customer count, employee count and rate base.[29] We describe these systems, amongst others, below.

JDE ERP and UltiPro HRIS Systems

PNG began implementation of the JDE ERP system, in May 2019 and it is expected to be complete by the end of June 2021.[30] As for the UltiPro HRIS system, it is being implemented in two phases, the first phase occurred in February 2020 and the second phase is expected to proceed during 2020.[31] PNG will allocate costs associated with the new JDE ERP and HRIS systems to PNG-West and the PNG(NE) divisions based on the composite average allocator and employee count allocator, respectively. The need for the new JDE ERP and UltiPro HRIS systems is a result of the corporate reorganization that took place in 2018, and the fact that AltaGas, the former parent company, would no longer provide certain services after June 30, 2020.[32]

PNG does not anticipate any annual cost savings associated with the new JDE and HRIS systems. However, by jointly implementing these systems with other TSU entities, rather than procuring a separate solution on a stand-alone basis, PNG submits it will benefit from shared project costs with the other participating entities. In addition, PNG submits that there are qualitative benefits associated with these projects, including the implementation of paperless processes that will allow PNG to significantly reduce the amount of manual rework required for coding errors. While this may not result in annual cost savings, these efficiencies will allow PNG's existing administrative staff to better support operational activities.[33] Operational benefits will be further realized as the CIS and HRIS systems are being configured to export files that can be uploaded into JDE ERP and avoid duplication of data entry for journal entries.[34]

CIS System

PNG is jointly implementing a new CIS system to replace the existing legacy system, which is expected to go-live in April 2021. PNG will allocate costs associated with the new CIS system to PNG-West and the PNG(NE) divisions based on customer count. PNG selected an SAP solution supported by VertexOne following a request for proposal process, based on the following factors:

- It has the lowest cost on a net present value basis and a shorter implementation timeframe;
- It will provide better customer service using more advanced technology;

[29] PNG(NE) Proceeding, Exhibit B-3, BCUC IR 18.1.1, 16.2.
[30] Exhibit B-2, p. 52; Exhibit B-3, BCUC IR 20.2.2.
[31] Ibid., p. 54.
[32] PNG-West Final Argument, p. 17; Exhibit B-2, pp. 51, 54.
[33] Exhibit B-3, BCUC IR 20.2, 21.5.
[34] Ibid., BCUC IR 20.2; Exhibit B-7, BCUC IR 97.4.

- It will enhance business processes and elevate them to industry standard practices; and
- It will result in internal staffing efficiencies and superior functionality.[35]

PNG considered maintaining its existing system; however, this option was rejected as the 20-plus year-old technology had limitations on customer experience and future enhancements would no longer be supported by the outsourcer, Vertex. As for the possibility of implementation of a stand alone CIS system, PNG also rejected this alternative based on the higher expected cost compared to joint CIS implementation and PNG's limited resources which would make it difficult to manage the implementation of a new CIS on its own.[36]

In addition to the joint CIS system resulting in the sharing of common costs, PNG anticipates savings for bill print and presentment of approximately $100,000 annually and has reflected these savings in test year 2021. PNG also expects to realize further financial benefits from the new CIS system commencing in year 2022 after the new CIS system has been fully implemented. At this time, PNG expects fewer internal resources will be required and plans to reduce the CIS technical support group by one headcount,[37] resulting in anticipated annual cost savings for PNG-West in the range of $51,000 to $71,800.[38]

However, net cost savings from the new CIS system will not be realized until 2032 onwards, as a result of the overall reduction in cost of service being more than offset by the higher depreciation charges from TSU for the first ten years of the CIS system's expected life.[39]

Other IT Projects

PNG will also be undergoing a Microsoft 365 transition, management of change initiative and Synergi Gas hydraulic modelling software implementation during the current Test Period.[40] PNG will allocate costs associated with each of these projects to PNG-West and the PNG(NE) divisions based on the composite average allocator.[41]

The transition to the Microsoft 365 platform is being undertaken jointly by PNG and its affiliates. Microsoft is phasing out support for legacy Windows platforms hence the need to implement Microsoft 365.[42] Through the Microsoft 365 transition PNG no longer needs to pay for Office Productivity licenses (i.e. Word, Excel, Outlook etc.) which reduces their annual contractor cost by $25,000 per year. However, the transition results in an incremental cost increase overall.[43]

The current management of change system does not adequately meet the requirements of the CSA Z662 for integrity, safety, and loss management, and therefore this system needs to be updated in order to comply with

[35] Exhibit B-2, p. 44; Exhibit B-3, BCUC IR 18.1 and 18.3.
[36] Exhibit B-3, BCUC IR 18.1.
[37] Ibid., BCUC IR 18.5; PNG(NE) Proceeding, Exhibit B-3, BCUC IR 10.2.
[38] Exhibit B-7, BCUC IR 96.5; PNG(NE) Proceeding, Exhibit B-6, BCUC IR 72.4 (PNG consolidated annual costs savings in the range of $100,000 to $140,000 less FSJ/DC of $46,000 to $64,000 and TR of $3,000 to $4,200).
[39] PNG(NE) Proceeding, Exhibit B-6, BCUC IR 72.3.
[40] Exhibit B-2, pp. 55, 102 and 111.
[41] Exhibit B-7, BCUC IR 124.1, 125.2; PNG(NE) Proceeding, Exhibit B-3, BCUC IR 18.1.1.
[42] PNG-West Final Argument, p. 17.
[43] Exhibit B-7, BCUC IR 104.1.

the standards and meet the expectations of the BC Oil and Gas Commission (BC OGC).[44] The management of change project commenced in the third quarter of 2019 and is expected to be complete by the end of 2020.[45] PNG's current hydraulic modelling system is aged and limited in its ability to interface with other systems. The Synergi Gas project is expected to commence in 2021 and is anticipated to be complete in 2022. This updated system will improve the real-time accuracy of PNG's system hydraulics, and more accurately inform decisions related to the need for main extensions, main upsizing or looping, and improve the timeliness of data refreshes and response to customer requests.[46] PNG expects to realize cost savings through efficiency improvements as a result of upgrading its existing system. However, these cost savings cannot yet be quantified. Further, PNG states that the updated system will ensure that PNG's IT systems are as accurate and up to date as possible, thereby helping to avoid costly error associated with unaccounted for change and inherent system limitations.[47]

GIS and ARM

Order G-151-18 in PNG-West's 2018-2019 RRA (PNG-West 2018-2019 Decision) approved the Geographical Information System (GIS), Asset Record Modernization (ARM) and Maximo asset management systems for PNG.[48] PNG is implementing the GIS over a three-year period from 2018 to 2020. The GIS project remains on budget and on schedule to deliver a fully operational system by the end of 2020. The ARM project is being executed over a five-year period from 2018 to 2022.[49]

PNG was directed in the PNG-West 2018-2019 Decision to file a report on the GIS and ARM projects in the 2020-2021 RRA, outlining detailed project benefits and any anticipated cost savings to be achieved.[50] In response to that directive, PNG submits that at this stage it is premature to assign any estimates to the costs that can be avoided by the introduction of the GIS project.[51] However, PNG expects to be in a position to associate cost savings with the GIS project at the end of 2020, once the project is completed.[52] PNG anticipates benefits such as increased system reliability and security, improved staff and contractor productivity, and more efficient regulatory processes upon project completion.[53]

The ARM project is being executed over a five-year period from 2018 to 2022.[54] PNG reports several benefits resulting from the ARM project, such as improved information accuracy, emergency response performance, system integrity management and management of change,[55] which are expected to result in cost savings and realized cost avoidance opportunities through the lifetime of an operating asset. However, PNG has not attempted to quantify annual cost related benefits to the list of compliance requirements and operational improvements, as there is considerable work to be completed on the ARM project beyond 2020. PNG emphasizes that this project continues to be pursued and justified for compliance purposes, for the effective

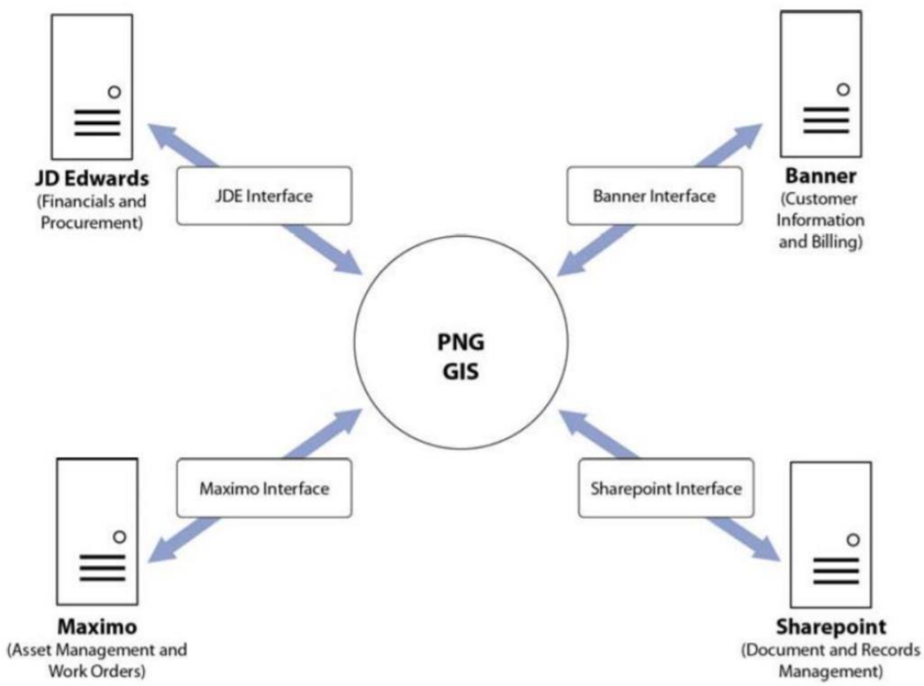
[44] PNG(NE) Proceeding, Exhibit B-3, BCUC IR 35.2.
[45] Exhibit B-3, BCUC IR 56.1.
[46] Exhibit B-2, p. 111; Exhibit B-7, BCUC IR 125.3.
[47] Exhibit B-3, BCUC IR 62.3.1.
[48] PNG-West 2018-2019 Decision, pp. 17 and 19 (Computerized Maintenance Management System (CMMS) and Maximo were confirmed to be the same asset management system in response to PNG(NE) Proceeding, Exhibit B-6, BCUC IR 79.1).
[49] Exhibit B-2, p. 161.
[50] Order G-151-18, directive 9.
[51] Exhibit B-2, pp. 160-161.
[52] Exhibit B-3, BCUC IR 84.1.
[53] Exhibit B-2, pp. 161-163.
[54] Ibid., p. 161.
[55] Exhibit B-2, p. 163.

management and retention of accurate, complete, verifiable, and retrievable pipeline system asset records as required under CSA Z662.[56]

PNG is implementing the Maximo system to support the planning and scheduling of all associated preventative maintenance and capital work.[57] The first phase of the Maximo project is expected to be fully operational by the end of 2020.[58] PNG(NE) notes that the Maximo costs will be unlikely to deliver any cost savings in the short or medium term. However, Maximo will allow more efficient management of assets and will become the main repository for information on assets, including maintenance requirements. Further, it will result in adequate asset condition information to allow the development of a risk-based inspection process which may deliver cost savings.[59]

In the PNG-West 2018-2019 RRA proceeding, PNG provides a network architecture diagram which shows the relationship between the various IT projects described above involving PNG-West and the PNG(NE) divisions.[60]

Figure 2: **Network Architecture Diagram**



Position of the Parties

BCOAPO accepts PNG's proposal for the "Customer information services (CIS) and IT Projects" as filed.[61]

---

56 Exhibit B-3, BCUC IR 84.1, 84.4.
57 Ibid., BCUC IR 10.1.1.
58 PNG(NE) Proceeding, Exhibit B-3, BCUC IR 16.1.
59 Ibid., Exhibit B-3, BCUC IR 17.1.
60 PNG-West Division 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 46 Series, Attachment BCUC 1.46a, p. 24.
61 BCOAPO Final Argument, pp. 12–13.

Panel Determination

The Panel accepts the 2020 and 2021 capital, operating and administrative expenditures associated with the above-noted IT projects, including the allocation of IT project costs between PNG-West and PNG(NE)'s FSJ/DC and TR divisions, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision.

The Panel has reviewed the evidence related to each individual IT project, in addition to the need for the new systems and the alternatives considered by PNG. Specifically, the Panel notes that the JDE accounting and HRIS payroll systems are required to address the change in PNG's parent from AltaGas to TSU. For the CIS project, the Panel notes that the new system is required to address the limitations of the existing system related to customer experience and the expectation that the existing system may no longer be supported by the current outsourcer in the future. Considering the need for these new IT systems, and the alternative analysis put forward by PNG, the Panel finds that the Test Period IT expenditures for these new systems are reasonable. In addition, the Panel recognizes that these projects offer opportunities for enhanced business processes, better customer service and internal staffing efficiencies as well as additional operational benefits yet to be identified upon project completion.

With respect to the methodology for allocating IT project costs between PNG-West and the PNG(NE) divisions, the Panel notes that PNG has used specific allocators from the methodology previously approved by the BCUC by Order G-114-13. The allocator used for each project has been selected based on the type of IT system and the nature of the benefits that the system provides. Accordingly, the Panel finds the allocation of IT project costs between PNG-West and the PNG(NE) divisions to be reasonable.

While the Panel has accepted the need for these projects at this time, it remains concerned with the anticipated financial benefits and the timing of any cost savings associated with these new systems. PNG does not currently anticipate any ongoing annual cost savings associated with the new JDE, HRIS and management of change systems nor Microsoft 365. Nonetheless, the evidence in this proceeding is sufficient to satisfy the Panel as to the need for these projects.

PNG provided cost savings associated with the CIS system, including the bill print and presentment savings achieved from the supplier through joint implementation and the reduction of one headcount for technical support. However, the net expected cost savings from the new CIS system will not be realized until 2032 onwards, due to depreciation charges from TSU for the first ten years of the CIS system's expected life offsetting the cost savings. Additionally, there are potential cost savings and cost avoidance opportunities associated with the Synergi Gas, GIS, ARM and Maximo projects which PNG has yet to quantify. These cost savings need to be quantified and anticipated cost savings, if any, appropriately applied to PNG's future revenue requirements once the projects have been implemented. **Accordingly, the Panel directs PNG-West to file a report detailing the following in the next RRA:**

- **Any change(s) in annual operating and administrative costs as a result of implementing each IT project, including the amount and details on what the change(s) relate to, specifying any cost savings realized as compared to the existing processes;**
- **The actual versus forecast 2020 and 2021 IT project costs for each of capital expenditures and operating/ administrative expenses, including detailed explanations for any significant variances for each IT project;**

- **An update on the timing schedule for each IT project, as necessary; and**
- **The net annual cost savings for the CIS, Synergi Gas, GIS, ARM and Maximo projects, specifying the annual cost savings achieved and the annual offsetting costs incurred, including operating and administrative expenses and the revenue requirement impact of the capital additions (i.e. return on equity and debt and depreciation charges).**

2.2 Pipeline System Integrity Management

PNG-West attributes increases to Test Period operating costs and capital expenditures part to activities related to pipeline system integrity management. The purpose of PNG-West's integrity management program is to ensure the protection of the public and the environment by demonstrating that all transmission and distribution assets are suitable for the continued provision of safe and reliable service.[62] The issue for the Panel to assess is the reasonableness of PNG-West's proposed Test Period expenditures related to integrity management. PNG-West takes the position that cost of service increases resulting from planned integrity management activities cannot be deferred as they are critical to ensuring continued provision of safe and reliable natural gas service.[63]

PNG-West notes that its pipeline assets are attracting increased attention by the BC OGC. The BC OGC's 2014 audit of PNG-West's operational strategies identified necessary improvements related to its segment-by-segment pipeline risk assessments, management of change processes, integrity program planning, and continual improvement processes.[64] PNG-West submits that improvements to its integrity programs have been made in recent years, however the segment-by-segment risk assessment is yet to be completed.[65] Beginning in January 2020, quarterly updates are being provided by PNG-West to the BC OGC regarding progress towards completion of this outstanding requirement. Further integrity related activities have also been recently mandated by the BC OGC. In February 2020, PNG-West was notified that their integrity management programs had been selected for a full and formal audit, and in March 2020, PNG-West was directed to provide integrity records regarding segments of pipelines constructed prior to 1979.[66]

Continued focus by the BC OGC on integrity related activities, in addition to other factors such as evolving industry best practices, have led PNG-West to develop systemic management practices and programs to enable proactive versus reactive operations by way of investment and continuous improvement.[67] Examples of integrity management related systemic improvements include PNG-West's Stress Corrosion Cracking Management Program and its Geohazards Management Program. PNG-West submits that both their Distribution Integrity Management Plan and their Transmission Integrity Management Plan are currently in the process of being updated.[68]

PNG-West acknowledges that since the loss of major customers in the early 2000s, it has consciously made some risk-based decisions to defer maintenance and integrity work due to cost pressures.[69] However, PNG-West states it is currently facing an elevated risk of pipeline incident and regulatory non-compliance. As a result,

[62] Exhibit B-3, BCUC IR 11.1 & 12.1 Attachments.
[63] PNG-West Final Argument, para 88.
[64] Exhibit B-7, BCUC IR 101.4.
[65] Ibid., BCUC IR 103.1 – Attachment BCUC 103.1b
[66] Ibid., BCUC IR 103.1 – Attachments BCUC 103.1c, 103.1d
[67] Exhibit B-3, BCUC IR 10.1.1.
[68] Ibid., BCUC IR 11.1 & 12.1
[69] Ibid., BCUC IR 10.1.1.

PNG-West is forecasting increases in both operating costs and capital expenditures due to the need to undertake integrity management activities.

Operating Expenditures

PNG-West states that increases to operating costs are driven by activities to address aging infrastructure concerns and to ensure compliance with pipeline integrity related codes, standards and regulations.[70] Examples of integrity related activities include investigative digs, right-of-way (ROW) clearing and geohazard management. These activities are part of the Pipeline Account, for which costs are forecast at $3.338 million and $2.696 million for 2020 and 2021, respectively. In comparison, actual Pipeline Account expenses were $1.671 million in 2019 and $1.814 million in 2018.[71]

Starting in 2018, PNG-West initiated a new approach to its investigative digs by prioritizing dig sites to ensure the most potentially injurious anomalies and pipeline defects were being addressed in a timely manner on a priority basis within the given budget and schedule.[72] In 2020 and 2021, PNG-West plans to continue this approach and expects a greater number of digs stemming from planned ILI runs. PNG-West forecasts costs for investigative dig activity to be $614,000 in 2020 and $558,000 in 2021, as compared to actual investigative dig costs of $430,000 in 2019 and $148,000 in 2018. [73] Higher costs for this Test Period relative to previous years are expected due to challenging access to remote areas of the pipelines. Furthermore, PNG-West states that due to the recent incorporation of EMAT technology for ILI runs in order to detect cracks and other linear anomalies, additional specialty integrity assessment resources are required during investigative digs and have been accounted for in the forecasts.[74]

ROW clearing operating costs are forecasted to increase considerably in the current Test Period relative to actual costs incurred in previous years. PNG-West forecasts ROW clearing expenses to be $530,000 in 2020 and $540,000 in 2021, as compared to actual ROW clearing expenses of $272,000 in 2019 and $223,000 in 2018. PNG-West acknowledges that over the past 20 years it has deferred some planned integrity management activities, including ROW clearing, in order to mitigate rate increases.[75] However, PNG-West explains that they can no longer defer such activities. To ensure compliance with BC OGC mandated requirements, PNG-West plans to increase ROW clearing efforts in the coming years which will entail higher costs.[76]

PNG-West submits that the growing focus from regulators and industry with respect to integrity and geohazard management has led to an expected increase, or in the least, sustainment of associated support costs.[77] PNG-West forecasts approximately $200,000 for each of test years 2020 and 2021 to support the development of a proactive geohazard identification and management system. Geohazards include, for example, river erosion and ground movements from landslides and seismicity. There were no geohazard identification and management operating expenses reported in 2019 or 2018.[78]

[70] PNG-West Final Argument, para 16.
[71] Exhibit B-3, BCUC IR 10.1.
[72] Ibid., BCUC IR 13.3.1.
[73] Exhibit B-2, Section 2.3.1, p. 37; Exhibit B-3, BCUC IR 10.1.
[74] Exhibit B-3, BCUC IR 13.4.
[75] Exhibit B-5, BCOAPO IR 3.1.
[76] Ibid.
[77] Exhibit B-3, BCUC IR 14.1.1.
[78] Ibid., BCUC IR 10.1.

Capital Expenditures

PNG-West submits that a significant component of planned capital expenditures relates to work necessary to maintain the integrity of natural gas transmission and distribution assets.[79] Specifically, PNG-West forecasts an increase in capital expenditures related to ILI runs and the Salvus to Galloway pipeline remediation project, which are discussed in Sections 3.2 and 4.1, respectively. Other notable capital expenditures include cut-out repairs and compressor station upgrades.

Capital expenditures related to EMAT ILI runs are forecasted to increase significantly relative to previous years. PNG-West forecasts capital expenditures for EMAT ILI runs to be $2,174,062 in 2020 and $2,893,975 in 2021, whereas actual expenditures were $334,188 in 2019 and $1,270,891 in 2018.[80] This increase in EMAT run costs is attributed to the fact that 2020 and 2021 will be the first years that more than one EMAT run will be completed in a given calendar year, with three EMAT runs in each year.[81] Several factors are identified as reasons for expanding the use of EMAT technology, specifically the technology's ability to accommodate PNG-West's diameter transmission lines due to recent tool advancements[82] and the technology's ability to detect stress corrosion cracks in pipelines – a growing concern given the vintage and characteristics of segments of PNG-West's transmission system.[83]

In the Application, PNG-West forecasts Salvus to Galloway remediation project expenditures to be $1.452 million in 2020 and $2.529 million in 2021.[84] PNG-West submits these costs are required to complete design developments, critical access improvements and repairs of high-priority dents and metal loss features for specific segments of the pipeline. The Salvus to Galloway remediation project is discussed in further detail in Section 4.1 below.

Other notable integrity related capital expenditures forecasted for the Test Period include investigative dig cut-out repairs and compressor station upgrades. PNG-West forecasts capital expenditures of $1.021 million for 2020 and $1.042 million for 2021 to address investigative dig cut-out repairs expected as a result of past and planned ILI runs.[85] In comparison, PNG-West incurred actual capital expenditures of $583,310 in 2019 and $449,023 in 2018 for dig cut-out repairs.[86] PNG-West submits that the remote geographic location of the planned ILI runs will result in increased logistical costs to complete anticipated cut-out repairs.[87]

With respect to compressor station upgrades, PNG-West forecasts capital expenditures of $1.347 million in 2020 and $1.239 million in 2021.[88] As a comparison, PNG-West incurred actual capital expenditures of $0.415 million in 2019 and $2.457 million in 2018. PNG-West states that it has had a history of deferring investments on its compressor stations due to cost pressures and is presently at the point where further delays pose operating and

79 PNG-West Final Argument, para 88.
80 Exhibit B-3, BCUC IR 13.3.
81 Ibid., BCUC IR 13.3.1.
82 Ibid., BCUC IR 49.3.
83 Ibid., BCUC IR 49.1.
84 PNG-West Final Argument, para 94.
85 Ibid., para 89.
86 Exhibit B-2, Section 3.1.1, 3.1.2, pp. 124, 130.
87 PNG-West Final Argument, para 89.
88 Ibid., para 99.

safety risks.[89] Proposed compressor upgrade work is driven largely by legislation (e.g. emission reduction), reliability and asset life replacement.[90]

Panel Determination

The Panel accepts the Test Period capital expenditures and operating expenses related to pipeline system integrity management, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

The Panel acknowledges that there are factors related to pipeline integrity that are contributing to greater forecast operating and capital expenditures during the Test Period. As PNG-West's evidence shows, these factors include heightened stakeholder integrity-related expectations, aging infrastructure, improvements in available technology and deferral of past integrity-related work. The Panel notes that PNG-West considers its overall understanding and appreciation of integrity management-based requirements to be continually maturing and broadening, and that this process will be accompanied by changes to operational practice and associated expenses. Notwithstanding the demonstrated need for inspections and repairs to some of PNG-West's pipelines, the Panel is concerned about the extent to which potentially increasing integrity related costs can be reasonably sustained by ratepayers into the future.

The Panel urges PNG-West to continue to include in future revenue requirement or certification of public convenience and necessity (CPCN) applications detailed discussions regarding the need for integrity management activities, in an effort to ensure the provision of safe and reliable service. However, future applications seeking approval of integrity management activity costs should continue to highlight project prioritization and alignment with overall system planning. Any integrity related costs which PNG-West considers necessary to comply with mandated regulatory requirements emanating from the BC OGC should be clearly identified.

The Panel notes that PNG-West states that both PNG-West's Distribution Integrity Management and Transmission Integrity Management plans are in the process of being updated. **Accordingly, PNG-West is directed to file the updated Distribution Integrity Management and Transmission Integrity Management plans in its next RRA.**

The Panel also notes that PNG-West submits that responses to several BC OGC mandated activities are currently still in a developmental stage. These activities include a Pipeline Segment by Segment Risk Assessment, an Aged Pipeline Condition Assessment and an Integrity Management Program (IMP) Audit. **Accordingly, PNG-West is directed to file as part of the next RRA a progress update regarding the Pipeline Segment by Segment Risk Assessment, the Aged Pipeline Condition Assessment and the IMP Audit.** The progress update shall include, for example, the current status of each activity, a schedule to complete the requirements for each activity and a summary of recommendations resulting from completed activities. In addition, the progress update should also include relevant information presented by PNG-West to the BC OGC to date, including the IMP Overview Presentations submitted as part of the IMP Audit and Risk Assessment Corrective Action Plan quarterly progress reports.

---

[89] Exhibit B-3, BCUC IR 51.1.
[90] Exhibit B-7, BCUC IR 118.1.

3.0 Cost of Service

3.1 Operating, Maintenance, Administrative and General Expenses

PNG-West is requesting recovery of the following operating, maintenance and administrative and general (OMA) expenses for the Test Period, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision:

Table 1: PNG-West OMA Expenses[91]

	Test Year 2020	Test Year 2021
Operating (net of transfers to capital and shared service cost recoveries from PNG(NE))	$11,692,000	$11,710,000
Maintenance	$575,000	$587,000
Administrative and General (net of transfers to capital and shared service cost recoveries from PNG(NE))	$8,720,000	$8,858,000
Total	**$20,987,000**	**$21,155,000**

The increase in forecast OMA expenses for 2020 is $2.768 million, which is subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision, is an increase of 15.2 percent as compared to 2019 forecast OMA expenses.[92] PNG-West submits that the primary drivers for the increase include:[93]

i. General inflationary pressures;

ii. Planned activities to address aging infrastructure concerns and ensure compliance with pipeline integrity related code, standards and regulations;

iii. Forecast labour cost increases attributable to new positions in the areas of engineering, Indigenous relations and field operations; and

iv. Increased administrative and general costs to replace the accounting and payroll systems and the transition to the Microsoft 365 platform (as discussed earlier in Section 2.1 of this decision), higher insurance expenses, increased rental costs for the relocated Vancouver office and higher consultant costs related to climate change policies.

The increase in forecast OMA expenses for 2021 is $168,000, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision, which is 0.8 percent higher than the 2020 forecast amount. The largest component, specifically 138,000 or 82 percent, of this increase is attributable to administrative and general expenses. The primary drivers of the increase in forecast administrative and general expenses over 2020 include:[94]

i. General inflationary pressures;

[91] Exhibit B-2 pp. 34, 47 and 49.
[92] Ibid.: 2019 forecast OMA expenses: $9,553,000 + $505,000 + $8,161,000 = $18,219,000.
[93] PNG-West Final Argument, pp. 7, 17; Exhibit B-2, pp. 34–35.
[94] Ibid., p. 17, Exhibit B-3, BCUC IR 25.1; Exhibit B-7, BCUC IR 106.1.

ii. Increased contractor costs primarily pertaining to the new accounting and payroll systems; and

iii. Forecast labour and bonus cost increases, partially offset by lower contractor costs anticipated for 2021.

Positions of the Parties

BCOAPO submits that it is not able to identify any particular category of operating expenses for 2020 and 2021 that it can definitively challenge but expresses the following concerns with respect to PNG-West's cost control measures:[95]

- PNG-West's actual gross operating expenses were $10.748 million in 2015, rising to a forecasted $14.725 million in 2020. BCOAPO submits that the increase is greater than the general inflation level and equates to 6.5 percent, compounded annually;
- PNG-West underspent on gross operating expenses by 6 percent or $728,000 in 2019, which amount was collected from ratepayers in 2019;[96] and
- PNG-West underspent on maintenance expenses in each year from 2017 to 2019.[97]

Based on the above, BCOAPO submits that "it is possible for a utility to over-forecast/underspend on O&M expenses to the benefit of the shareholder while making up for the consequences of any under-spending at the next rates proceeding by requesting a large increase in O&M."[98]

In reply, PNG-West observes that actual gross operating costs increased by $673,000 between 2015 to 2019, or $168,000 per year, equivalent to a rate of increase of approximately 1.6 percent per year. PNG-West considers this to be equivalent to an inflationary level. PNG-West acknowledges that the increase in operating costs forecast for 2020 is significant but argues that this increase is supported by evidence on record. It submits that the increase should not be characterized as being out of line and out of control over the course of the past five years. Further, PNG-West notes that of the identified underspending in gross operating expenses of $728,000 in 2019, $275,000 is attributed to GIS-related costs and $254,000 is attributed to Maximo licensing costs that were subsequently considered to be capital in nature. The remaining $199,000 equates to a 1.6 percent underspending which PNG-West does not consider to be unreasonable. PNG-West observes that excluding the 2019 variance discussed, its actual gross operating expenses were below forecast by an average of $19,000 per year between 2015 and 2018 and maintenance expenses were below forecast by $87,000 per year between 2015 and 2019.[99]

Lastly, PNG-West submits that an average underspending on O&M expenses in the range of $100,000 per year on a budget of more than $10 million is not unreasonable and should not be construed to confer a significant benefit on PNG-West.[100]

---

[95] BCOAPO Final Argument, p. 10.
[96] Ibid., p. 11.
[97] Ibid., p. 12.
[98] Ibid., p. 12.
[99] PNG-West Reply Argument, pp. 4–5.
[100] Ibid., p. 5.

Panel Determination

The Panel accepts the 2020 and 2021 OMA expenses requested by PNG-West, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

The Panel shares BCOAPO's concern with respect to PNG-West's cost control measures and apparent pattern of underspending in the range of $100,000 per year. Generally, underspending on OMA expenditures as compared to forecast is to the benefit of the shareholder as opposed to the ratepayer. Going forward, the Panel expects that PNG-West will make greater effort to ensure that its forecasts in the test period better reflect actual expenditures to minimize the risk of ratepayers over-paying for expenditures that do not ultimately materialize. That said, the Panel has reviewed the evidence and PNG-West's stated reasons for the increase in OMA expenses in test years 2020 and 2021. The Panel finds that the OMA expenses requested for recovery in 2020 and 2021 are reasonable, subject to the determinations on the issues addressed in Section 3.3 below**.**

3.2 Accounting Treatment of In-Line Inspection Tool Runs

PNG-West requests approval to capitalize costs pertaining to MFL in-line inspection (ILI) runs, on the basis that they are similar to inspection activities of EMAT ILI runs, and accordingly, should have the same accounting treatment as previously approved by the BCUC.[101] Pursuant to those previous orders, PNG-West's EMAT ILI runs are currently capitalized to BCUC Account 469 and amortized over a period of ten years.[102]

PNG-West's ILI runs are a key component of its pipeline system integrity management program. The ILI runs consist of periodically sending tools inside PNG-West's natural gas pipelines in order to detect integrity issues such as metal loss or dents. There are different types of ILI runs employed by PNG-West, primarily EMAT, MFL, a combination thereof, and caliper tools.[103] Prior to the proposed capitalization of the abovementioned MFL ILI run, forecast operating costs for pipeline inspection activities, are $961,000 in 2020 and $272,000 in 2021; and forecast expenditures for capitalized ILI runs are $2,174,000 in 2020 and $2,894,000 in 2021.[104] Should PNG-West's proposal be accepted, one significant MFL ILI run totalling $817,014 planned for 2020 and included in PNG-West's operating expenses (BCUC Account 665) will be capitalized and reclassified to BCUC Account 469. [105]

Prior RRA decisions involving PNG-West and PNG(NE) divisions discussed the accounting treatment for all ILI tool run costs. Specifically, in PNG-West's 2016-2017 RRA, PNG-West took the position that US GAAP allows for the capitalization of major inspections under certain circumstances, and EMAT ILI runs should therefore be afforded similar treatment.[106] In both the PNG-West 2016-2017 RRA Decision and the PNG-West 2018-2019 Decision, the BCUC directed PNG-West to capitalize the EMAT ILI runs on the basis that this was permitted under US GAAP[107] and would provide relief against lumpy and volatile expenditures during a particular test period.

[101] Approval requested in Exhibit B-7, BCUC IR 102.1.1; Orders G-131-16 and G-151-18.
[102] Exhibit B-7, BCUC IR 102.1.1.
[103] Exhibit B-2, Section 2.3.1, p. 35.
[104] Ibid., Section 2.3.1, p. 36; Section 2.13.1.1.1, pp. 98-99; Section 2.13.1.1.2, pp. 107-108.
[105] Exhibit B-7, BCUC IR 102.1.1.
[106] US GAAP ASU 2014-09, Revenue from Contracts with Customers, section 340-40-25-8; US GAAP ASC 980-340-25-1; US GAAP ASC 908-360-25 [PNG-West 2018-2019 RRA, Exhibit B-3, BCUC IR 30.1; Exhibit B-6, BCUC IR 75.2].
[107] PNG-West 2016-2017 RRA Decision (G-131-16), Section 4.1, pp. 17-18; PNG-West 2018-2019 Decision (G-151-18), Section 4.4, pp. 22-25.

PNG-West submits that there have been significant developments and advancements in MFL ILI technology in recent years allowing for MFL ILI run results to provide a similar longevity benefit as those employing EMAT technology. These advanced technologies produce similar useful baseline conditions and long-term information to improve pipeline useful life and are on similar recurring schedule frequencies. Similar to EMAT ILI runs, PNG-West also notes that MFL tool runs can result in large and volatile rate impacts if expensed during a test year. Accordingly, PNG-West views there should be no distinction between the accounting treatment for MFL ILI runs and that for EMAT ILI runs and requests approval to capitalize MFL tool runs. PNG-West proposes to continue to expense smaller regular pigging ILI runs, with any variances recorded in a deferral account, noting both accounting treatments (capitalizing and expensing ILI runs) are in accordance with US GAAP. [108]

Positions of the Parties

BCOAPO accepts PNG-West's proposal to capitalize MFL ILI runs.[109]

Panel Determination

The Panel approves PNG-West's proposal to capitalize costs arising from MFL ILI runs to BCUC Account 469 for depreciation over a ten-year period.

The Panel accepts that, similar to EMAT ILI runs, significant MFL ILI runs provide valuable information that offers long term benefits to the integrity of transmission pipelines, as well as representing significant costs which can vary year over year. Further, the Panel considers that capitalization of these costs, as permitted under US GAAP, provides relief against volatile rate impacts that result from expensing these costs on a one-time basis in the year when they occur.

Given that MLF ILI runs are similar pipeline inspection tools to EMAT ILI runs that are eligible for capitalization in accordance with US GAAP, and taking into account the BCUC's previous decisions approving the capitalization of expenses for EMAT ILI runs, the Panel finds it reasonable that MLF ILI runs should also be capitalized.

3.3 Shared Corporate Services Costs

PNG seeks approval to recover in customer rates the full Shared Corporate Services Costs allocated by its parent company, TSU, of $1.835 million in 2020 and $1.872 million in 2021 on a consolidated basis. In prior test periods, PNG only sought and received approval for recovery of a portion of the Shared Corporate Services Costs in rates, which is discussed further in the History section below.[110]

PNG also seeks approval to record a portion of the above-noted cost allocation in a deferral account in order to mitigate the impact on customer rates, with the disposition of the deferral account to be determined at a future date. PNG requests approval to record $1.078 million in 2020 and $1.099 million in 2021 in the deferral account.[111]

---

[108] Exhibit B-7, BCUC IR 102.1.1.
[109] PNG-West requested approval for its proposed accounting treatment of MFL ILI runs in Exhibit B-7, BCUC IR 102.1.1.
[110] Exhibit B-2, Section 2.5.7.1, p. 63.
[111] Ibid., Section 2.5.1, p. 50, Table 20; Section 2.5.7.1, pp. 63-64.

In the sections that follow, the Panel provides some historical context for the Shared Corporate Services Costs and separately addresses the amount of Shared Corporate Services Costs and the request for approval of deferral account treatment.

<u>History</u>

As noted earlier, AltaGas acquired PNG on December 20, 2011 and PNG transitioned from being a standalone public company to a wholly owned subsidiary of a public company. After the acquisition PNG no longer needed to directly incur expenses to maintain its public reporting status. Instead, these costs were incurred by AltaGas on behalf of PNG and its other subsidiaries, in addition to other costs such as tax consultancy fees and certain insurance costs. AltaGas allocated a portion of its Shared Corporate Services Costs to PNG and its other subsidiaries using the Modified Massachusetts Formula.[112]

In late 2018, PNG's parent company, AltaGas undertook a corporate reorganization whereby it established ACI as a new standalone public company. On March 31, 2020, the PSPIB and the ATRFB completed the purchase of all issued and outstanding common shares of ACI,[113] and ACI's name was changed to TSU.[114]

TSU provides services to directly support its wholly owned subsidiaries in a variety of areas, including governance, business oversight, financing, administration, legal, accounting and regulatory.[115] The costs for these services are referred to as Shared Corporate Services Costs and are allocated to TSU's subsidiaries, including PNG, using the Modified Massachusetts Formula.[116] This methodology is consistent with standard industry practice and does not differ from the allocation methodology that was used by PNG's previous parent, AltaGas.[117]

As noted above, PNG only sought to recover a portion of the total Shared Corporate Services Costs in customer rates in prior years, noting that it ultimately expected to seek recovery of all costs allocated by its parent as economic circumstances improved.[118] In 2019 for example, the forecast and actual Shared Corporate Services Costs were $1.159 million[119] and $1.777 million respectively.[120] However PNG only proposed and received BCUC approval to recover $743K in customer rates.[121] PNG's current request for approval to include the full Shared Corporate Services Costs reflects an increase of $1.092 million over the amount approved by the BCUC in the PNG-West 2018-2019 Decision.[122]

---

[112] Order G-130-12 and accompanying reasons for decision, section 7.3, p. 23; PNG-West 2013 RRA, Exhibit B-1, p. 12.
[113] TSU Press Release dated December 19, 2010 (https://trisummit.ca/index.php/newsroom/news-2019/217-ltaasanadanchareholdersppproverrangementnvolv20191219134200)
[114] TSU Fiscal 2020 Second Quarterly Report, Management's Discussion and Analysis, The Company, p. 2 (https://trisummit.ca/images/pdf/TSU_Q2_2020_Combined_Doc_MDAFS_FINAL.pdf)
[115] Exhibit B-2, Appendix B, Section 4.1, p. 3
[116] Ibid., pp. 3-5
[117] Exhibit B-3, BCUC IR 32.1.
[118] PNG-West 2013 RRA, Exhibit B-1, p. 13; PNG-West 2014 RRA, Exhibit B-1, Section 2.5.1, p. 31; PNG-West 2015 RRA, Exhibit B-2, Section 3.1, p. 14; PNG-West 2016-2017 RRA, Exhibit B-1-1, Section 2.5.1, p. 45; PNG-West 2018-2019 RRA, Exhibit B-1-1, Section 2.5.1, p. 44.
[119] The Decision 2019 Shared Corporate Services Costs of $1.159 million was established by AltaGas under the assumption that a large gas utility that AltaGas would have a significant impact on reducing the allocation to all its subsidiaries under the MMF formula. [PNG-West Exhibit B-3, BCUC IR 29.1]
[120] Exhibit B-3, BCUC IR 29.1.
[121] Ibid.
[122] Exhibit B-2, Section 2.5.1, p. 50, Table 20.

3.3.1 Full Recovery of Shared Corporate Services Costs

PNG seeks approval to record the full Shared Corporate Services Costs of $1.835 million in 2020 and $1.872 million in 2021 in cost of service. PNG submits that the Shared Corporate Services Costs provide benefits to PNG, which include achieving economies of scale, expanding its access to capital, sharing expertise and best practices, and having the ability to share the costs associated with the necessary corporate services without incurring the full standalone costs of those services.[123] PNG submits that these costs are fair, reasonable and prudently incurred.[124]

PNG allocates the costs between PNG-West and the PNG(NE) divisions using the cost allocation methodology approved by the BCUC in Order G-114-13.[125] The cost allocation breakdown between PNG-West and the PNG(NE) divisions from 2019 to 2021 is illustrated in table 2 below:[126]

Table 2: Cost Allocation between PNG-West and PNG(NE)

Cost Allocation ($000's)	Decision 2019	Test Year 2020	Test Year 2021
PNG-West	468	1,160	1,207
PNG(NE) – FSJ/DC	259	634	624
PNG(NE) – TR	16	41	42
Consolidated	**743**	**1,835**	**1,872**

** The consolidated amount may not total due to rounding; Table prepared by BCUC*

PNG-West maintains that full recovery of the Shared Corporate Services Costs is appropriate at this time as ratepayers will benefit from incremental near-term volumes associated with energy exports in its service territory. In addition, there are potential, significant ratepayer benefits related to RECAP. [127] The RECAP refers to the open season that was conducted in spring 2020 to secure long-term, high-volume contractual arrangements with customers for unutilized capacity on the PNG-West system. PNG-West received bids following the RECAP with a total requested volume of 163.0 MMSCFD for delivery and expects to execute Transportation Service Agreements with the parties.[128]

PNG prepared a fair value estimate of the Shared Corporate Services Costs and filed this in the Application and an alternative estimate was also provided during the IR process. Both estimates are examined below.

<u>Fair Value Estimate</u>

To provide support for the reasonableness of the Shared Corporate Services Costs, PNG's management prepared a fair value estimate of the 2020 and 2021 Shared Corporate Services Costs, consisting of a summary of the estimated costs PNG would have incurred as standalone pubic company (Fair Value Estimate).[129] KPMG LLP

[123] Exhibit B-2, Section 2.5.7.1, p. 63; PNG-West Exhibit B-3, BCUC IR 30.2, 30.3.
[124] Exhibit B-2, Section 2.5.7.1, p. 63.
[125] Exhibit B-2, Section 2.11, p. 81.
[126] Exhibit B-2, Section 2.5.1, p. 50, Table 20.
[127] Exhibit B-2, Section 2.5.7.1, p. 63.
[128] Exhibit B-10-1, Panel IR 1.1.
[129] Exhibit B-2, Appendix B, Section 4.2, p. 5.

(KPMG) was retained by TSU's predecessor[130] in November 2019 to perform an independent assessment of the Fair Value Estimate and the results are summarized in a report dated February 27, 2020 (KPMG Report).[131]

The Fair Value Estimate of $4.071 million in 2020 and $4.154 million in 2021 categorizes the Shared Corporate Services into four functions and is summarized in table 3 below:[132]

Table 3: Estimated Fair Value of Shared Corporate Services

Shared Corporate Service Function	Standalone employee and third party costs2020	Standalone employee and third party costs 2021
Board of Directors	$824,073	$840,554
Executive Management	2,256,747	2,301,882
Less: PNG President	(520,000)	(530,400)
Total Executive Management	1,736,747	1,771,482
Corporate Resources (incl. Legal & Compliance)	560,647	571,859
Accounting, Tax & Finance	949,639	969,651
Total	**$4,071,105**	**$4,153,547**
Shared Corporate Services cost [proposed recovery]	1,835,433	1,872,142
Savings to PNG	**$2,235,671**	**$2,281,405**

**note totals may not reconcile due to rounding differences*

PNG made several assumptions in arriving at the Fair Value Estimate, including those listed below. As part of its overall assessment, KPMG evaluated the reasonableness of PNG's assumptions as outlined below.

- The services of seven members of the board of directors would be required, including one executive and six non-executive members. The board of director costs are based on compensation data for "micro companies" published by Korn Ferry (Korn Ferry Report), having an average and median assets size of approximately $800 million.[133] In comparison, PNG's asset base is $289.3 million.[134] To assess the reasonableness of the costs, KPMG compared them to those of FortisBC Energy Inc. (FortisBC) and TSU, respectively.[135]
- The current President would be replaced by a Chief Executive Officer (CEO) and a Chief Financial Officer (CFO). PNG based the compensation for these positions on the total direct compensation paid by TSU for these same positions. KPMG compared the cost estimates to FortisBC's costs per public filings and the '2019 CA Mercer Total Compensation Survey for the Energy Sector – General Benchmark' (Mercer Survey).[136]
- A general legal counsel would be required. The general counsel's role and seniority is assumed to be comparable to that of TSU's general counsel. For reasonableness KPMG evaluated the compensation to base salary amounts in the "Robert Half 2020 Salary survey" (Robert Half Survey), and noted the amount

[130] KPMG was retained by ACI, as the KPMG report was issued prior to the change in name from ACI to TSU on March 31, 2020.
[131] Exhibit B-2, Section 2.5.7.1, p. 64.
[132] Ibid., Appendix B, Section 4, p. 3; Section 4.1, pp. 3-5.
[133] Ibid., Appendix B, Section 4.2.1, pp. 6-7.
[134] Exhibit B-13, Panel IR 4.1.
[135] Exhibit B-2, Appendix B, Section 4.2.1, pp 6-7.
[136] Ibid., Section 4.2.2, pp. 7-8.
2019 CA Mercer Total Compensation Survey for the Energy Sector – General Benchmark' (the "Mercer Survey"). The Mercer Survey provides companies with industry benchmarks for different types of organisations and positions to consider in setting their compensation levels.

falls within the 50th to 95th percentile range.[137] PNG notes the Robert Half Survey does not include benefits or other compensation amounts.[138]

- PNG would require two additional accounting staff, an Assistant Controller and a Treasury/Investor Relations Resource, and would incur additional accounting, tax and finance costs. PNG based their compensation on the Mercer Survey. KPMG compared these costs to the Robert Half Survey, noting that the base salary amounts fall within the 50th to 95th percentile range.[139]

With respect to the comparisons to FortisBC and TSU for board costs and executive management compensation PNG acknowledges that both utilities are larger than PNG in terms of assets, revenues, customers and gigajoules (GJ) distributed. However, PNG contends they are comparable on the basis that they are utilities operating in Western Canada.[140]

In its report, KPMG offers the view that PNG applied an objective and rational methodology in developing the Fair Value Estimate.[141] Furthermore, PNG notes the Fair Value Estimate is greater than the TSU allocated amount and based on this difference, PNG submits that the costs are prudent and reasonable.[142]

Alternative Cost Estimate

PNG also provided an alternative estimate of $2.678 million for the 2020 costs to operate as a standalone public company, which uses actual 2011 costs as the base (Alternative Cost Estimate).[143] The Alternative Cost Estimate of $2.678 million represents incremental costs that would be incurred by PNG to operate as a standalone public company in 2020, recognizing that there are certain costs already included in PNG's 2020 revenue requirements.[144]

Table 4 below provides a reconciliation from the 2011 actual costs of $961,015 to the Alternative Cost Estimate of $2.678 million, based on the evidence filed by PNG in the current proceeding:[145]

---

[137] Exhibit B-2, Appendix B, Section 4.2.4, pp. 9-10.
[138] Exhibit B-3, BCUC IR 34.10.
[139] Exhibit B-2, Appendix B, KPMG Report, Section 4.2.3, pp 8-9.
[140] Exhibit B-13, Panel IR 4.1.
[141] Exhibit B-2, Appendix B, Section 4.2.5, p. 10.
[142] Ibid., Section 2.5.7.1, p. 65.
[143] Exhibit B-3, BCUC IR 32.4.
[144] Ibid.
[145] Ibid.; Exhibit B-13, Panel IR 3.2.

Table 4: Corporates Shared Services Costs

PNG's Corporate Shared Services Costs (Note 6)	Actual 2011 Costs (Note 1)	Difference	Estimated 2011 Costs (Note 2)	Inflation Factor (Note 3)	Costs Inflated	Costs Removed / Added (Note 4)	2020 Additional Market Adjusted Costs
Directors' fees and expenses	360,147	(85,094)	275,053	126.68%	348,437		348,437
Executive Management (Note 5)		1,046,201	1,046,201	134.39%	1,406,007	(306,425)	1,099,582
Annual Report	30,551	15,288	45,839	117.17%	53,710		53,710
Shareholder expenses (Computershare, TSX, Broadridge, Bowne)	94,048	(11,819)	82,229	117.17%	96,348		96,348
Investor Relations	5,718	(605)	5,113	117.17%	5,991		5,991
Investor relations – printing	4,432	(2,847)	1,585	117.17%	1,857		1,857
Investor relations - accommodations		1,841	1,841	117.17%	2,157		2,157
Investor relations - meals & entertainment		1,841	1,841	117.17%	2,157		2,157
Investor relations - transportation		6,902	6,902	117.17%	8,087		8,087
Audit fees	234,035	13,517	247,552	117.17%	290,057	(180,000)	110,057
Internal audit fees	51,022	26,178	77,200	117.17%	90,455	(50,000)	40,455
DBRS fee		27,000	27,000	117.17%	31,636	(35,000)	24,000
Director's & Officer's insurance	58,000	5,500	63,500	117.17%	74,403	137,582	211,985
Fiduciary insurance	23,650	600	24,250	117.17%	28,414	(14,415)	13,999
Additional Liability Insurance ($150MM coverage)						238,206	238,206
Crime insurance						35,000	35,000
Cyber insurance						33,603	33,603
Non-owned aircraft insurance						2,500	2,500
Provincial registration fees						37,304	37,304
Translation fees						84,183	84,183
Legal fees	43,812	55,575	99,387	117.17%	116,452		116,452
Consultant fees	55,600	40,259	95,859	117.17%	112,318		112,318
Total	**961,015**	**1,140,337**	**2,101,352**		**2,668,467**	**(585,840)**	**2,678,369**

Notes:

1) The actual 2011 costs are those reported in the PNG-West 2013 RRA and represent the costs incurred by PNG when it was a standalone public company prior to the AltaGas amalgamation. Reproduced from response to BCUC IR 24.2 in Exhibit B-3 of the PNG-West's 2013 RRA.
2) PNG states that these are the estimated 2011 costs. These are different from costs referenced in Note 1 because the 2011 source data for the estimated costs is based on 2012 budget data included in PNG-West 2012 RRA and 2011 actual costs incurred.
3) Inflation factor of 3 percent used on Directors Fees and Executive Salaries, based on the inflation factor applied for these costs historically.[146] Inflation factor of 2 percent used for all other cost elements.
4) This column represents adjustments for the following: (a) certain costs that were not incurred at PNG in 2011 and would need to be incurred in 2020 if PNG were a standalone public company; (b) market driven costs (specifically insurance) which are adjusted to 2019 actual costs incurred by TSU; and (c) removal of costs which are already included in the 2020 revenue requirements in order to reflect the incremental public company costs for 2020. To clearly reflect the movement from the "Costs Inflated" to "2020 Additional Market Adjusted Costs" the BCUC revised this column from that in the referenced IR to show the incremental increases and reductions in costs.
5) PNG included $1,046,201 in the "Estimated 2011 Costs" to reflect the 2011 compensation costs for the President & CEO, VP Corporate Development & Treasurer, and VP Finance. These costs were not included in the "Actual 2011 Costs" (Note 1) as these positions did not have the public reporting responsibilities of being a standalone public company at the time those costs were reported. PNG removed costs of $306,425 to account for the compensation costs for the VP Finance, which are already included in PNG's 2020 revenue requirements.
6) The BCUC noted some minor issues with the clerical accuracy of the reconciliation. However, the items noted were not considered material in nature.

There are two large adjustments contributing to the difference between the 2011 actual costs of $961,015 and the Alternative Cost Estimate of $2.678 million, specifically executive management costs and insurance cost.

With respect to executive management costs, the Alternative Cost Estimate includes costs of $1,099,582 related to the following two positions: President & CEO and VP Corporate Development & Treasurer. PNG submits these positions do not presently exist at PNG and would be considered incremental costs that PNG would have to incur as a standalone public company.[147]

In addition to the two positions noted above and the associated costs, PNG also directly employs the following four executive management positions in 2020: President, Senior VP Operations and Engineering, VP Finance, and

[146] Exhibit B-13, Panel IR 3.1.1

[147] Exhibit B-3, BCUC IR 32.4; Exhibit B-13, BCUC IR 3.6.

VP Regulatory Affairs, Legal & Gas Supply.[148] The compensation costs associated with these positions are included in PNG's revenue requirements and are therefore not included in the Alternative Cost Estimate. PNG provided the 2020 compensation costs for these positions in confidential IR responses.[149]

The second major adjustment between the 2011 actual costs of $961,015 and the Alternative Cost Estimate relates to insurance costs, including: directors & officers insurance, additional liability insurance, and crime, cyber and non-owned aircraft insurance. The key drivers of the increase in insurance relate to (i) an escalation in insurance premiums on directors' and officers' lability insurance policies due to increased litigation and losses experienced in the insurance industry between 2011 and 2020; and (ii) the incremental premium PNG would have to pay for the full $150 million liability limit if it were a standalone public company.[150]

Positions of the Parties

BCOAPO does not take a position on the Shared Corporate Services Costs in its Final Argument for this proceeding. However, BCOAPO addresses this matter in its Supplemental Final Argument in this proceeding and its Final Argument for the PNG(NE) 2020-2021 RRA proceeding (PNG(NE) Proceeding).

In BCOAPO's supplemental argument in this proceeding it expresses concerns regarding the three percent inflation rate used in the Alternative Cost Estimate for directors' fees and expenses and executive management costs.[151] BCOAPO also recommends that the BCUC "not accept the notion of an estimated, hypothetical stand-alone cost as the basis for definitively determining the appropriateness of the instant proposal." BCOAPO submits the estimate based on comparators has the potential to represent the highest cost an entity would incur for the service.[152] Accordingly, BCOAPO asserts that "a line-by-line assessment as undertaken by the BCUC in its extensive IRs on the issue, along with the historical record and appropriate adjustments for inflation where required, provides a superior approach to assessing the proposal".[153]

In reply, PNG submits that the three percent inflation factor applied to directors' fees and expenses and executive management costs is based on current market data and notes applying an inflation rate of one percent does not reduce the Inflationary estimate to an amount less than the 2020 forecast Shared Corporate Services Costs.[154] PNG submits that while the Fair Value Estimate is greater than the Inflationary Estimate, both are in excess of the proposed Shared Corporate Services Costs to PNG, and there is no evidence to support the assertion that the estimates represent the highest cost.[155]

Panel Discussion and Determination

PNG-West is approved to record its allocation of the Shared Corporate Services Costs incurred by its parent TSU of $1.835 million in 2020 and $1.872 million in 2021 in its revenue requirements. In addition, the allocation of the specified amounts in 2020 and 2021 between PNG-West and the PNG(NE) divisions using the allocation methodology previously approved by Order G-114-13 is hereby approved, as follows:

[148] Exhibit B-13, Panel IR 3.6.
[149] Ibid., Panel IR 3.6.
[150] Ibid., Panel IR 3.1.
[151] BCOAPO Supplementary Final Argument, p. 3.
[152] Ibid., p. 4.
[153] Ibid., p. 5.
[154] PNG Supplemental Reply Argument (August 21, 2020), Section 2.1, pp. 1-2.
[155] Ibid., Section 2.2.1, pp. 2-3.

Table 5: Approved Shared Corporate Services Costs Allocation between PNG-West and PNG(NE)

Cost Allocation	Test Year 2020 ($000s)	Test Year 2021 ($000s)
PNG-West	1,160	1,207
PNG(NE) – FSJ/DC	634	624
PNG(NE) – TR	41	42
Consolidated	**1,835**	**1,872**

** The consolidated amount may not total due to rounding; Table prepared by BCUC*

The issue for the Panel to consider is whether to approve the recovery in rates of the full corporate services cost allocation of $1.835 million in 2020 and $1.872 million in 2021, respectively. The Panel notes that PNG has only sought and received BCUC approval to recover a portion of the Shared Corporate Services Costs in recent years. Accordingly, the request for full recovery will create upward pressure on rates during this Test Period.

In considering whether to approve the Shared Corporate Services Costs, the Panel has considered the reasonableness of these costs in relation to the benefits they provide to PNG's ratepayers. PNG has put forward evidence regarding the corporate services provided by its parent, TSU, on behalf of PNG and the other subsidiaries, including governance, business oversight, financing, administration, legal, accounting and regulatory services. These services are necessary in order for PNG to maintain its capital structure and access capital, which is essential in light of upcoming capital requirements. These services are critical for any utility and without TSU, PNG would need to acquire these services on its own. The Panel acknowledges that the services provided by TSU give both direct and indirect benefits to PNG and its ratepayers, including achieving economies of scale, expanding access to capital, and sharing in corporate services costs without incurring the full standalone costs on its own. For the foregoing reasons, the Panel finds that some allocation of costs between PNG's parent and PNG is appropriate, considering the services provided by TSU and the benefits achieved by PNG as a result of those services.

In making its determinations on whether to approve the full amount of the Shared Corporate Services Costs, the Panel has reviewed the evidence related to the value of these services and costs for PNG and its ratepayers in order to assess the reasonableness of the full allocation amount. During the course of the proceeding, PNG has provided two estimates with which to compare the full Shared Corporate Services Costs: the Fair Value Estimate, which the KPMG Report reviewed, and the Alternative Cost Estimate, which is based on actual 2011 cost information escalated to the current Test Period. The Panel notes that these estimates do not purport to quantify the precise value of the shared corporate services provided by TSU on behalf of PNG and instead merely establish a point of reference with which to assess the reasonableness of the allocation amount. The Panel assesses the particulars and merits of the two estimates below.

<u>Fair Value Estimate and KPMG Report</u>

The Panel acknowledges PNG's assertion that the Fair Value Estimate provides support for the full Shared Corporate Services Costs in 2020 and 2021. Specifically, PNG highlights that the Fair Value Estimate exceeds the

Test Period cost allocation, which indicates savings resulting from being a subsidiary of TSU as opposed to a standalone public company. The Panel also recognizes that the Fair Value Estimate has been supported by KPMG.

That said, the Panel has concerns regarding the assumptions and comparators used for the Fair Value Estimate and agrees with BCOAPO that the Fair Value Estimate may represent the highest costs that a utility would incur for the service. Specifically, the Panel notes that the board of director costs are based on compensation data published in the Korn Ferry Report for “micro companies” with an average and median asset base that is significantly greater than PNG’s. In addition, the Panel notes that executive management costs are based on direct compensation paid by TSU, and the cost estimate was compared against FortisBC’s public filings. Both utilities are significantly larger than PNG in terms of asset base, revenues, number of customers and delivery volumes.

Finally, the Panel notes that the Fair Value Estimate assumes that a general counsel would be required if PNG were a standalone public company and the role and seniority would be comparable to TSU’s general counsel. While the Panel expresses no view on PNG’s need for a general counsel, it notes that TSU is a much larger entity. Accordingly, and consistent with the discussion above, the Panel is not persuaded that TSU is a reasonable proxy for establishing the fair value of the internal legal costs for its subsidiary, PNG.

For these reasons, the Panel finds the costs in the Fair Value Estimate to be overstated and does not consider this estimate to be an acceptable basis upon which to determine the reasonableness of the quantum of PNG’s Shared Corporate Services Costs for the Test Period.

Alternative Cost Estimate

The Alternative Cost Estimate represents incremental costs required for PNG to operate as a standalone public company. PNG developed the Alternative Cost Estimate of $2.678 million in response to BCUC IRs and elaborated in Panel IRs. The Panel notes that the Alternative Cost Estimate is based on actual 2011 costs, adjusted for inflation and with certain costs added or removed as required. The Panel favours this method of assessment as it avoids the problem of choosing appropriate comparators as required when using the Fair Value Estimate method. For this reason, the Panel finds that the Alternative Cost Estimate is a more reasonable basis against which to compare the full 2020 Shared Corporate Services Costs of $1.835 million and assess their reasonableness.

As noted above, executive management costs are the largest driver of the increase in the 2011 Shared Corporate Services Costs of $961,015 to the estimated 2020 costs of $2.678 million. In reviewing these costs, the Panel has considered the current PNG executive management positions. The following is a list of the positions for which compensation costs are included in either PNG’s 2020 revenue requirements or the incremental 2020 Alternative Cost Estimate:

List 1: PNG Executive Management Positions

Included in 2020 revenue requirements

- President
- VP Regulatory Affairs, Legal & Gas Supply
- VP Finance;
- Senior VP Operations and Engineering

Included in Alternative Cost Estimate

- President & CEO
- VP Corporate Development & Treasurer

The Panel interprets the above summary to reflect the total executive management positions and costs PNG considers would be required to operate as standalone public company in 2020. The Panel has several concerns regarding the incremental executive management costs included in the Alternative Cost Estimate.

First, the Panel notes that compensation costs for the President are already included in the 2020 revenue requirements and incremental costs for a President & CEO are included in the Alternative Cost Estimate. This evidence indicates that there may be a duplication of costs related to the compensation for the President's duties. The Panel considers that only a reasonable amount of compensation directly attributable to the responsibilities of a CEO should be included as an incremental cost in the Alternative Cost Estimate. Accordingly, the Panel finds the inclusion of the total compensation costs for the President & CEO position in the Alternative Cost Estimate to be overstated. PNG has filed the 2020 compensation costs for the President in confidence. In making its final determinations, the Panel has considered the impact of reducing the Alternative Cost Estimate by the amount of the confidential 2020 compensation costs for the President.

Second, the Panel notes that the summary above indicates a need for five executive management positions. However, as a standalone public company in 2011, PNG had the following four executive positions: President & CEO, VP Corporate Development & Treasurer, VP Finance and Senior VP Operations and Engineering. While the Panel recognizes that PNG's circumstances and requirements may have changed since 2011, the Panel is not persuaded the compensation costs for all five executive positions represent a reasonable amount for a utility of PNG's size. Specifically, the Panel notes that Alternative Cost Estimate includes a VP Corporate Development & Treasurer position and PNG has not explained how the costs for this position would not overlap with those of the existing VP Finance. Accordingly, the Panel finds that the incremental executive management costs in the Alternative Cost Estimate appear to be overstated. In making its final determinations, the Panel has considered the impact of removing the compensation costs for the VP Corporate Development & Treasurer from the Alternative Cost Estimate.

The Panel notes that insurance costs are also a significant driver of the incremental increase in costs between 2011 actual costs of $961,015 and the 2020 Alternative Cost Estimate of $2.678 million. The Panel has reviewed these costs and the supporting evidence provided by PNG and accepts the rationale put forward by PNG for adding these incremental insurance costs.

Based on the analysis and discussion above, the Panel considers that the 2020 Alternative Cost Estimate could be reduced by the actual 2020 compensation costs for the current PNG President and the 2020 compensation costs for one other executive position, for example, the VP Corporate Development & Treasurer. However, the Panel notes that the Alternative Cost Estimate is only one method of evaluating the potential costs for PNG if it were to operate as a standalone public company and there are other factors to take into consideration given the changes in PNG's circumstances between 2011 and 2020. For example, as part of the Fair Value Estimate assessed by KPMG, PNG notes that there are several non-executive positions that may be required if PNG were to operate as a standalone public company, specifically an Assistant Controller and Treasury/Investor Relations Resource. However, these positions are not included in the Alternative Cost Estimate and do not presently exist at PNG.

In summary, the Panel considers that while the 2020 Alternative Cost Estimate of $2.678 million could be reduced by the executive management costs for the President and one other executive position, that estimate may nonetheless be increased due to the requirement for other non-executive positions. As noted above, the Alternative Cost Estimate simply provides a point of reference with which to assess the reasonableness of the allocation amount, rather than a precise calculation. While we express no view on the precise Alternative Cost Estimate of $2.678 million, we find that on balance the Alternative Cost Estimate provides support for the reasonableness of the Shared Corporate Services Costs, even after taking into account the potential adjustments discussed above.

The Panel recognizes BCOAPO's concern with respect to applying an inflation factor of a three percent to directors' fees and expenses and executive management costs. However, based on the discussion above, the Panel does not consider that an adjustment to the inflation factor would have a material impact on the reasonableness of using the 2020 Alternative Cost Estimate as support for the 2020 Shared Corporate Services Costs.

The Panel acknowledges that the Shared Corporate Services Costs allocated to PNG by its parent, TSU, are significantly greater than previously approved. However, the Panel accepts that PNG has put forward sufficient evidence to support the reasonableness of the Shared Corporate Services Costs. With respect to the increase in costs and the impact on ratepayers, the Panel addresses this in the section below on the appropriate deferral account treatment for these costs.

3.3.2 Shared Corporate Services Costs Deferral Account

As noted earlier, PNG recognizes the recovery of the full Shared Corporate Services Costs from TSU will result in an increase in customers' rates. Accordingly, PNG-West is seeking approval to establish a new interest bearing deferral account to record a portion of the Shared Corporate Services Costs for future recovery as the BCUC may determine. The table 6 below illustrates the full cost allocation, the amount proposed to be recorded in the Shared Corporate Services Costs deferral account and the net amount to be recovered from customers in test years 2020 and 2021 by PNG-West and the PNG(NE)'s divisions. The net amount to be recovered in rates after the allocation to the deferral account is equal to an inflationary increase of two percent over the historical consolidated amount allowed for recovery in the PNG-West 2018-2019 Decision. For example, in the PNG-West 2018-2019 Decision the BCUC approved $743K to be recovered in customer rates for PNG consolidated, and the proposed amount to be recovered in Test Year 2020 is $756K, two percent greater.[156]

[156] Exhibit B-2, Section 2.5.1, pp. 50-51, Table 20; Section 2.5.7.1, p. 63-64.

Table 6: PNG-West and PNG(NE) - Cost Allocation, Cost Deferral and Cost of Service Impact

Cost Allocation, Cost Deferral and Cost of Service Impact by Division ($000's)		Decision 2019	Test Year 2020	Test Year 2021
PNG-West	Cost Allocation (as above)	468	1,160	1,207
	Cost Deferral	-	676	700
	Cost of Service Impact	468	484	507
PNG(NE) – FSJ/DC	Cost Allocation (as above)	259	634	624
	Cost Deferral	-	377	374
	Cost of Service Impact	259	255	250
PNG(NE) – TR	Cost Allocation (as above)	16	41	42
	Cost Deferral	-	24	25
	Cost of Service Impact	16	17	17
Consolidated	**Cost Allocation (as above)**	**743**	**1,835**	**1,872**
	Cost Deferral	**-**	**1,078**	**1,099**
	Cost of Service Impact	**743**	**756**	**773**

** Totals may not sum due to rounding*

PNG-West plans to seek approval for the amortization of the Shared Corporate Services Costs deferral account in future years as PNG-West increases customer volumes.[157] PNG-West believes that the amortization of the Shared Corporate Services Costs deferral account would depend upon the successful outcome of the RECAP to ensure that customer rates are not adversely impacted. It hopes that a successful outcome will enable PNG-West to seek amortization of the deferral account commencing in 2022; however, to the extent that the RECAP project results in lower than anticipated revenues or revenues to be realized over a longer period, PNG-West submits that it is possible that the amortization of the deferral account may be delayed beyond 2022.[158] In the event that RECAP does not proceed or does not result in any incremental large volume industrial transportation volumes, PNG-West would expect to recover the balance of the deferral account from customers in the future. PNG-West notes that should it become aware of other financial impacts on customer rates, favourable or unfavourable, those additional revenues or costs could also impact the amortization start date and the length of the amortization period.[159]

PNG-West states that under a scenario where it is approved to recover the full amount of the Shared Corporate Services Costs for Test Years 2020 and 2021 and does not defer any portion thereof, residential customer rates would increase by approximately two percent in test year 2020, with no material change in test year 2021.[160]

PNG-West also provides the following table to illustrate the estimated rate impact for its residential customers in PNG-West assuming the deferral account is amortized over one, three and five years starting in 2021, assuming 2021 deliveries and 2021 customer rates remain constant for the future years.[161]

[157] Ibid., Section 2.5.7, p. 62; Section 2.5.7.1, p. 63-64.
[158] Exhibit B-7, BCUC IR 108.1.
[159] Exhibit B-7, BCUC IR 108.2, 108.3.
[160] Exhibit B-3, BCUC IR 31.3.
[161] Ibid., BCUC IR 31.4.

Table 7: Amortization and Estimated Rate Impact

		[------------------------------		Amortization	Amortization			
		Year 2021	Year 2022	Year 2023	Year 2024	Year 2025	Year 2026	Year 2027
One Year amortization period								
2020 addition to deferral account	676,000	676,000						
2021 addition to deferral account	700,000		700,000					
Total Amortization		676,000	700,000	-	-	-	-	-
Impact on Annual Revenue Requirement		676,000	24,000	(700,000)	-	-	-	-
Incremental Annual Impact on Residential Customer rates		1.86%	0.06%	-1.84%	0.00%	0.00%	0.00%	0.00%
Three Year amortization period								
2020 addition to deferral account	676,000	225,333	225,333	225,333				
2021 addition to deferral account	700,000		233,333	233,333	233,333			
Total Amortization		225,333	458,667	458,667	233,333	-	-	-
Impact on Annual Revenue Requirement		225,333	233,333	-	(225,333)	(233,333)	-	-
Incremental Impact on Residential Customer rates		0.62%	0.62%	0.00%	-0.60%	-0.62%	0.00%	0.00%
Five Year amortization period								
2020 addition to deferral account	676,000	135,200	135,200	135,200	135,200	135,200		
2021 addition to deferral account	700,000		140,000	140,000	140,000	140,000	140,000	
Total Amortization		135,200	275,200	275,200	275,200	275,200	140,000	-
Impact on Annual Revenue Requirement		135,200	140,000	-	-	-	(135,200)	(140,000)
Incremental Impact on Residential Customer rates		0.37%	0.37%	0.00%	0.00%	0.00%	-0.36%	-0.37%

PNG-West suggests that the proposed Shared Corporate Services Costs deferral account attracts a short-term interest rate in anticipation of the deferral account being amortized immediately following a successful RECAP. However, PNG is amenable to applying the weighted average cost of debt rate if a longer amortization period is considered to be more appropriate.[162]

Positions of the Parties

BCOAPO does not address the Shared Corporate Services Costs deferral account in its Final Argument in this proceeding, but does address it in its Final Argument in the PNG(NE) Proceeding.

Panel Determination

The Panel approves a new Shared Corporate Services Costs deferral account with a three-year amortization period and accruing interest at PNG-West's weighted average cost of debt, and PNG-West is directed to record in the deferral account its allocated portion of the consolidated Shared Corporate Services Costs of $676,000 in 2020 and $700,000 in 2021.

Similar to PNG, the Panel recognizes the impact that the full recovery of Shared Corporate Services Costs from TSU will have on rates. At the same time, the Panel has concerns regarding PNG-West's proposal to defer the full Shared Corporate Services Costs for an unspecified length of time with no set amortization.

While the Panel acknowledges PNG-West's statements that the potential, incremental volumes resulting from the RECAP may mitigate the rate impact of amortization of the deferral account in future, the Panel notes that Shared Corporate Services Costs are not one time expenses but instead are recurring expenses that are likely to persist in future test periods. Accordingly, with no set amortization of the deferral account balance, the balance in the deferral account will likely continue to increase exponentially over the years, which will impact ratepayers in several ways. First, the balance in the deferral account attracts compounding interest, which will ultimately be paid by ratepayers. Second, as the deferral account balance grows, so too does the likelihood of a significant

[162] Exhibit B-7, BCUC IR 107.5.

rate impact once the amortization of the deferral account commences. Lastly, deferring the costs over a longer timeframe will increase intergenerational inequity, as future ratepayers will pay a larger portion of costs incurred in the Test Period. Based on the foregoing, the Panel finds that it is unreasonable to defer a portion of the Shared Corporate Services Costs indefinitely with no plan for the recovery of these amounts.

The Panel has reviewed above the rate impact of including the full Shared Corporate Services Costs in rates in the years incurred (i.e. 2020 and 2021) and the impact if these amounts are deferred and amortized over a period of one, three and five years. The Panel recognizes that the full recovery in 2020 and 2021 would increase residential rates by approximately 2 percent in 2020 and agrees with PNG-West that a deferral account mechanism would mitigate this rate impact. In the Panel's view, the amortization period for the amount deferred should balance the benefits of rate smoothing with upholding intergenerational equity. The Panel acknowledges that longer amortization periods will generally increase costs for ratepayers due to the accumulation of interest charges and the inflationary increases in Shared Corporate Services Costs. In reviewing the options of a one, three and five-year amortization period, the Panel finds that a three-year amortization period is warranted, as this period realizes the benefits of smoothing rates while avoiding an inordinately long amortization period.

The Panel also recognizes that the interest rate applied to the Shared Corporate Services Costs deferral account should not exceed the minimum amount in order to avoid rate shock. In the PNG-West 2013 RRA Decision the BCUC established key principles for the treatment of deferral accounts including the appropriate interest rate to be applied given the type of costs being deferred (capital or non-capital) and the amortization period. For deferral accounts for non-capital costs which are amortized beyond one year, the utility's weighted average cost of debt should be applied. In consideration of the Panel's approval of a three year amortization period for the balance captured in the deferral account the Panel finds the weighted average cost of debt to be the appropriate interest rate for the deferred portion of Shared Corporate Services Costs and is satisfied that this interest rate will not result in rate shock.

3.4 Automotive Cost Allocation

In PNG(NE)'s 2018-2019 RRA Decision accompanying Order G-164-18A (PNG(NE) 2018-2019 Decision), the BCUC noted the variance between actual automotive costs on a divisional basis and those that are forecast using the existing automotive allocation methodology. Accordingly, the BCUC directed PNG(NE) to review the effectiveness of the automotive cost allocation methodology and provide recommendations for future allocation of costs among PNG-West and the PNG(NE) divisions. PNG completed a review, provided the results and proposed amendments in the Application, which are discussed below.

First, with respect to the basis for the consolidated automotive cost pool that is used in the methodology, PNG proposes to use actual costs of the prior year with a two percent provision for inflation.[163] Historically, the forecast was based on recent cost experience and anticipated changes in underlying costs (i.e. trend in fuel costs, carbon tax, etc.). PNG compared historic results to forecasts using the inflationary approach and found a reduction in forecast error. [164]

[163] In consideration of a 2-year RRA, the first test year would be inflated 2 percent over the prior year actual and the second test year inflated 2 percent over the forecast of the first test year.
[164] Exhibit B-2, Section 3.4.1.7, p. 174.

Second, PNG reviewed the historical approach for allocating the forecast consolidated automotive cost pool to capital and is satisfied that it is appropriate to continue with the current budgetary conventions as follows: [165]

- apply the divisional percentage of capital labour costs of consolidated labour costs to the consolidated automotive cost pool; and
- apply the current administrative convention of allocating actual automotive costs to capital whereby a 15 percent factor is applied to capital labour costs and capitalized.

Third, PNG recommends amending the historical approach for allocating the forecast consolidated automotive cost pool to operating costs. Historically, the allocation of forecast costs was based solely on the divisional proportion of labour hours. PNG now proposes applying the following approach: [166]

- once the consolidated automotive cost pool has been established, subtract the costs identified as being attributable to capital in order to arrive at the operating cost pool; and
- apply the five-year rolling average of each division's actual percentage distribution of operating automotive costs to the test year operating cost pool.

PNG compared the historical results of allocating forecast operating costs to the amended approach and noted the amended approach reduced the range of over (under) allocations and removed the bias for over allocating automotive costs to PNG(NE).[167]

As a consequence of reflecting the alternate forecast methodology in the Test Period, operating automotive costs allocated to PNG-West are $515,000 and $520,000 for test years 2020 and 2021, respectively, as compared to $469,000 allocated to PNG-West in the PNG-West 2018-2019 Decision. This results in a correspondingly lower allocation of automotive costs to PNG(NE) FSJ/DC and PNG(NE) TR in test years 2020 and 2021 as compared to the PNG(NE) 2018-2019 Decision.[168]

Position of the Parties

BCOAPO does not take a position on PNG's proposal for automotive cost allocation methodology.

Panel Determination

The Panel approves the automotive cost forecast for the Test Period, which is based on the revised allocation methodology as filed in the Application.

The Panel is satisfied with PNG's review of the effectiveness of the historic automotive cost allocation methodology, in compliance with BCUC Order G-164-18A, and its recommendations moving forward. PNG's proposed revisions to the automotive cost allocation methodology for the current Test Period appear to reduce forecasting error and remove bias in over/under allocations on a divisional basis. Accordingly, the Panel finds PNG's proposed revisions to the automotive cost allocation methodology to be reasonable.

---

[165] Ibid., pp. 171, 173.
[166] Ibid.
[167] Ibid., p. 172.
[168] Exhibit B-2, Section 2.3.5, p. 42; PNG(NE) Proceeding, Exhibit B-2, Section 2.3, p. 29.

Notwithstanding the revised methodology being reasonable, the Panel encourages PNG to continue to review and assess the effectiveness of the revised automotive cost allocation methodology with respect to variances in forecast and actual expense allocations and recommend revisions in future RRAs as necessary.

3.5 Interest Rates

PNG-West forecasts the underlying prime rate for operating line borrowings in both test years 2020 and 2021 using the forecast 90-day treasury bill rate for 2020 from BMO's published forecast dated November 22, 2019. Additionally, PNG-West's revolving term facilities are forecast, based on the 90-day treasury bill rate from BMO's November 22, 2019 forecast. Moreover, in test year 2021, the interest rate forecast for PNG-West's two floating rate long-term debt rate instruments is forecast to be the same as test year 2020, as the November 22, 2019 BMO report did not have forecasts for 2021 available at the time of the filing of the Application. [169]

PNG-West submits that with the changing economic conditions, BMO published a forecast dated March 27, 2020 which shows that the forecast 90-day treasury bill rate for 2020 declined from 1.6625 percent to 0.4875 percent and notes the BMO publication also includes a forecast for 2021 of 0.20 percent.[170] The revised 90-day treasury bill interest rate forecast would reduce PNG-West's forecast 2020 and 2021 short term and long term debt interest rates and have the following associated impact on debt costs over Test Period:[171]

- 2020 short term and long term debt costs would decrease by $105,000 and $364,000, respectively, and PNG-West estimates that delivery rates to residential customers would decline by approximately 1.1 percent or by $11.58 to the average residential annual bill.
- 2021 short term and long term debt costs would decrease by $143,000 and $447,000, respectively, and PNG-West estimates that delivery rates to residential customers would decline by approximately 1.3 percent or by $13.86 to the average residential annual bill.

PNG-West relies on the short term and long term deferral accounts to capture the variances in the actual and forecast debt rates financing costs. Given the current uncertainty in the capital markets, and the inability to be able to forecast what terms for the renewal of the operating facility may be provided in May 2021, PNG-West proposes to rely on these deferral accounts to capture any differences in financing costs for test years 2020 and 2021.[172]

Positions of the Parties

BCOAPO does not address interest rate forecast in its Final Argument for this proceeding. However, BCOAPO addresses this matter in its Final Argument for the PNG(NE) Proceeding and states that when a forecast is used to establish key parameter to be embedded in costs that make up the revenue requirement, "the preference should be to use the most recent forecast available."[173]

In reply, PNG(NE) submits that, although it believes the interest rate deferral account mechanism in place will achieve a comparable result, it is amenable to the BCOAPO's recommendation for PNG(NE) to reflect the BMO March 2020 forecast interest rates in the regulatory schedules and in the determination of final approved rates.

[169] Exhibit B-2, Section 2.14.1, pp. 116-117; Exhibit B-3, BCUC IR 67.4.
[170] Ibid., p. 116; Exhibit B-3, BCUC IR 67.4.
[171] Exhibit B-3, BCUC IR 67.4; Exhibit B-5, BCOAPO IR 1.8; Exhibit B-7, BCUC IR 127.1.
[172] Exhibit B-2, Section 2.14.1, pp. 116-117; Exhibit B-3, BCUC IR 67.4; Exhibit B-5, BCOAPO IR 1.8.
[173] PNG(NE) Proceeding, BCOAPO Final Argument, p. 7.

PNG(NE) notes that this specific matter was not addressed in the Final Arguments on the PNG-West 2020-2021 RRA but any direction regarding interest rates would most appropriately be addressed as part of the BCUC's review of the final regulatory schedules for both entities.[174]

Panel Determination

The Panel directs PNG-West to update the interest rate forecasts in its final regulatory schedules to reflect the BMO March 2020 forecast interest rates.

The Panel recognizes that PNG-West has short term and long term interest deferral accounts to address the impact of differences between the forecast and actual interest rates during the Test Period. However, the Panel notes there are advantages of using the most recent information available in developing forecasts and is persuaded that applying the more recent forecast of interest rates to the PNG-West 2020-2021 RRA is warranted.

4.0 Rate Base / Capital Expenditures

PNG-West has forecast capital expenditures before overhead to be $13.908 million in 2020 and $15.385 million in 2021, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.[175] PNG-West submits that the planned capital spending over the Test Period is of a comparable magnitude to expenditures from recent years, including $17.860 million in 2018 and $11.497 million in 2019.[176]

PNG-West states that a significant portion of planned capital expenditures for 2020 and 2021 relates to work necessary to maintain the integrity of its ageing natural gas transmission and distribution infrastructure.[177] We discuss pipeline system integrity related capital expenditures in greater detail in Section 2.2 above.

One of the notable non-recurring projects planned for the Test Period is the Salvus to Galloway remediation project. Work during the Test Period involves critical access improvements and repairs of high priority dent and metal loss features. The project is addressed in greater detail in Section 4.1 below.

PNG-West's proposal for annual reporting on significant capital expenditures in response to directive 5 of Order G-151-18 is discussed in Section 4.2 below. PNG-West's proposed capital expenditures related to IT Projects are discussed in Section 2.1 above.

Position of the Parties

BCOAPO accepts PNG-West's Capital Expenditures as filed.[178]

---

[174] Ibid., PNG(NE) Reply Argument, p. 5.
[175] Ibid., Section 2.13.1.1, p. 94; PNG-West Final Argument, p. 10.
[176] PNG-West Final Argument, para 87.
[177] Ibid., para 88.
[178] BCOAPO Final Argument, p. 12.

Panel Determination

The Panel accepts PNG-West's Test Period capital expenditures of 13.908 million in 2020 and $15.385 million in 2021, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

Significant capital expenditures, such as IT Projects, EMAT ILI Runs and the Salvus to Galloway Remediation, are discussed individually in Sections 2.1, 3.2 and 4.1, respectively. As for the balance of capital expenditures, the Panel is satisfied that PNG-West has demonstrated a need for them as submitted within this Application. The Panel accepts the capital expenditures to be completed in the test years 2020 and 2021, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

4.1 Salvus to Galloway Remediation

PNG-West includes capital expenditures of $1.90 million in 2020 and $2.22 million in 2021 related to the Salvus to Galloway Remediation project in its Application, which represents a significant non-recurring capital expenditure for the Test Period.[179] The work in the current Test Period relates to the planning, detailed design development, critical access improvements and repair of high-priority dents and metal loss features for certain segments of the Salvus to Galloway pipeline. The Test Period capital expenditures for this project represent a small portion of anticipated costs for a much broader remediation project expected in the near future.[180] PNG-West states that it will seek approval for the remaining large and complex remediation project through a CPCN application to be submitted in the third quarter of 2020.[181]

PNG-West notes in its final regulatory schedules that Test Period capital expenditures for this project will be lower than initially proposed, in order to remove general development costs which benefit multiple Salvus to Galloway remediation projects.[182] PNG-West states that the identified general development costs for the Salvus to Galloway project total $1,853,414 for the period 2018 to 2021.[183] While PNG-West has not provided a breakdown of the general development costs by year, it has indicated that the proposed change in allocation of these costs results in a $4,000 decrease in revenue requirement for 2020 and a $77,000 decrease in revenue requirement for 2021.[184]

Remediation work on the Salvus to Galloway segment of the Prince Rupert 8" transmission mainline requires a multi-year effort to address integrity concerns which began in 2018 and is scheduled to be completed in 2023.[185] Approval for critical and high-priority repair activities is sought as part of the current RRA, and the remaining remediation projects will be submitted separately for approval as part of the forthcoming CPCN application.[186] PNG-West submits that it is imperative to begin work immediately on the identified critical repair activities to avoid the loss of both the 2020 and 2021 construction windows.[187] PNG-West confirms that the work proposed in the Application will go into service during the Test Period and that no project expenditure to be incurred

179 Exhibit B-3, BCUC IR 50.6.
180 Exhibit B-7, BCUC IR 117.4.
181 Ibid.
182 Exhibit B-9, BCUC Panel IR 2.2.1.
183 Ibid.
184 PNG-West Final Argument, para 22.
185 Exhibit B-2, Section 2.13.1.1.1, p. 99; PNG-West Final Argument, para 95.
186 Exhibit B-9, BCUC IR 2.5.1.
187 Exhibit B-7, BCUC IR 117.2.

during the Test Period will increase pipeline system capacity beyond the original design or licensed operating pressure, nor will the remediation work result in any form of extension to the existing system.[188]

PNG-West considers the repair work to be an extremely high priority.[189] Following completion of an inline inspection on the Salvus to Galloway pipeline in 2018, PNG-West identified a significant number of metal loss and dent features.[190] Of the identified integrity features, PNG-West further prioritized those that are either defined as defects requiring inspection and repair under CSA Z662 or were identified as having concerning characteristics in need of further investigation.

In addition to metal loss features, PNG-West identified and prioritized geohazards along the Salvus to Galloway pipeline through completion of pre-development studies in 2018-2019.[191] These geohazards (e.g. landslide, rockfall, hydraulic scour or accretion, flood, avalanche) result in a risk of rupture of the pipeline. These geohazards present a risk to the pipeline at a higher level than other pipelines in industry.[192] PNG-West states that the metal loss and geohazard risks are cause for immediate completion of discrete scopes of high-priority repairs to maintain safe and reliable service.[193]

PNG-West submits that forecasted costs, before any adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision, for the work to be completed in test years 2020 and 2021 are at a Class 3[194] level of definition. Those costs fall into three categories:

1) Engineering and Design costs totalling $791,000 in 2020 and $497,000 in 2021;
2) Material Procurement costs totalling $25,680 in 2020 and $613,000 in 2021; and
3) Construction costs totalling $753,000 in 2020 and $756,000 in 2021.[195]

PNG-West states it has completed comprehensive risk workshops and developed a risk register with associated controls and mitigation measures for this work.[196]

In response to BCUC IRs, PNG-West provided a high-level commentary on alternative overall remediation strategies.[197] Strategies were evaluated qualitatively based on cost and achievement of project objectives, such as reduction in risk, regulatory compliance and longevity of repair solution. In response to IRs regarding project execution risks, PNG-West stated that it has completed a comprehensive risk workshop and provided a risk registry as a confidential attachment.[198] PNG-West also submitted confidential Salvus to Galloway engineering reports, including a feasibility report, a design basis memorandum and a geohazard mitigation plan.
While the BC OGC has not issued any recent orders against PNG-West regarding this segment of pipeline, such orders have been issued in the last 20 years directly associated with this pipeline segment and its overall state of

---

188 Exhibit B-9, BCUC Panel IR 2.3, 2.4.
189 Exhibit B-3, BCUC IR 50.3.
190 Ibid., BCUC IR 50.7.
191 Exhibit B-3, BCUC IR 50.3.
192 Ibid.
193 Exhibit B-7, BCUC IR 117.4.
194 BCUC CPCN Application Guidelines: "Class 3 estimates are typically prepared to support full project funding requests, and become the first project phase 'control estimate' against which all actual costs and resources will be monitored for variations to the budget." (p.8). The degree of cost estimate accuracy, or Class, is defined in the most recent revision of the applicable Association for the Advancement of Cost Engineering (AACE) International Cost Estimate Classification System Recommended Practices.
195 Exhibit B-7, BCUC IR 117.1.
196 Exhibit B-3, BCUC IR 50.4.
197 Ibid., BCUC IR 50.2.
198 Ibid., BCUC IR 50.4.

integrity and PNG-West risk management.[199] PNG-West confirms that this segment of pipeline is currently subject to a BC OGC mandated risk assessment that must address a variety of threats and consequences as outlined in applicable codes and standards.[200] Furthermore, PNG-West submits that this segment of pipeline has been selected by the BC OGC for full condition review under its "Aged Pipeline Condition Assessment" project which assesses the overall condition and integrity management sufficiency of operating pipeline assets in BC that are 50 years of age or more.[201]

Panel Determination

The Panel accepts the capital expenditures for Salvus to Galloway remediation project to be completed in the Test Period, subject to the adjustments identified by PNG-West during the regulatory process and summarized in Appendix A to this decision and the directives and determinations in this decision.

The Panel considers that PNG-West has provided sufficient evidence to demonstrate the need for the Salvus to Galloway repair work to be completed in this Test Period. The Panel is satisfied that the work proposed for the Test Period represents a discrete project phase which will address pipeline integrity repairs necessary to maintain regulatory compliance and safe operations.

The Panel notes that the costs associated with the phase of Salvus to Galloway repairs to be completed in test years 2020 and 2021 are significant, and that these costs represent but a small portion of a larger remediation effort to follow in a subsequent CPCN application. Considering the magnitude of the current and future costs required to address integrity concerns on this length of pipeline, the Panel urges PNG-West to continue to investigate all cost-effective alternatives which would continue to provide safe and reliable service to PNG-West customers.

The Panel notes that PNG-West has identified certain general development costs for the Salvus to Galloway project which total $1,853,414 for the period 2018 to 2021 but has not provided a breakdown of these costs by year. **Accordingly, the Panel directs PNG-West to include in its final regulatory schedules filed within 30 days of this decision, a breakdown of the general development costs by year and the 2020 and 2021 forecast of the Salvus to Galloway capital expenditures, after deducting any general development costs.**

4.2 Reporting on Significant Capital Projects

In PNG-West's 2018-2019 RRA, the BCUC 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 when a CPCN process would be appropriate. By Order G-151-18 the BCUC directed PNG-West to file a proposal for a report to be filed annually, which outlines future construction of extensions and new facilities as well as significant system modifications or additions that are planned (Capital Report) and include recommendations for:[202]

- The form the annual report should take;
- The timing of the report;
- The regulatory review process;

[199] Ibid., BCUC IR 50.7.1.
[200] Ibid., BCUC IR 50.7.1.
[201] Ibid., BCUC IR 50.7.1.
[202] Order G-151-18 with reasons for decision, Section 2.1, p. 9.

- 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.

We discuss below the following key elements of PNG-West's proposed Capital Report:

(i) the content it should take, including the level of detail and the capital projects that should be included/excluded;

(ii) the minimum capital dollar reporting threshold;

(iii) the timing of the report; and

(iv) the regulatory review process.

We also discuss whether there is a need to establish a minimum dollar threshold for CPCNs for PNG-West.

Content of the Capital Report

PNG-West proposes that the Capital Report include specific information for forecast and historic capital expenditures. Reporting on forecast capital expenditures would be limited to planned, non-recurring capital projects which would capture system extensions, new facilities and significant system modifications or additions as well as items that pertain to the maintenance and operation of existing assets or other non-discretionary items. PNG-West proposes to exclude planned recurring capital expenditures from the reporting as these are generally projects for normal course capital activities.[203]

The proposed format would include a description of the project, type of project, level of accuracy for the cost estimate (AACE estimate class), actual costs spent to date, forecast costs for the next year and each year thereafter through to completion. In addition, the Capital Report would also provide the estimated construction commencement dates, and confirmation of intention to file to the BCUC for approval of a CPCN or section 44.2 UCA expenditure schedule as may be required or appropriate.[204]

PNG-West's proposed reporting on historic expenditures comprises a variance analysis of capital expenditures for the preceding calendar year, consistent with the capital expenditure variance analysis provided in its RRAs.[205] PNG-West submits that there may be capital projects of urgent need in order to address unanticipated operational risks or customer in-service requirements, and as such, there may be projects that commence construction prior to the proposed Capital Report being filed with the BCUC. To the extent that these projects meet the requirements for the filing of a CPCN, PNG-West submits a CPCN would be filed as soon as reasonable cost estimates could be completed.[206]

Minimum Dollar Threshold for the Capital Report

PNG-West proposes a minimum total capital project expenditure of $500,000 for project reporting purposes. This threshold was determined after PNG-West completed a historic review of non-recurring capital expenditures and identified that most of the individual projects exceeded the $500,000 threshold and

[203] Exhibit B-2, Section 3.4.1.1, pp. 153-154.
[204] Ibid., pp. 155; Exhibit B-3 BCUC IR 81.1.
[205] Ibid., p. 155.
[206] Exhibit B-3 BCUC IR 81.2.

accordingly capital projects of lesser amounts would likely not warrant further examination through a separate review process. PNG-West submits the $500,000 threshold strikes a reasonable and appropriate balance of meeting the directive from the BCUC while not creating an onerous workload in order to prepare a report that will require additional resources and compliance costs.[207]

PNG-West submits that its two-year RRAs will continue to identify individual projects that exceed a threshold of $50,000. Therefore, a higher threshold is proposed for this supplemental compliance reporting to be filed annually.[208]

Timing of Report

PNG-West proposes that the Capital Report be an element of the Annual Report which is filed with the BCUC by April 30 each year. PNG-West notes that this approach would be consistent with the standard practice of many other utilities currently under BCUC's jurisdiction. [209]

Regulatory Review Process

PNG-West proposes the nature of the regulatory review process for the Capital Report would be subject to the BCUC's discretion but recognizes where the Capital Report would be an element of the Annual Report, that the information would be reviewed by BCUC staff as part of the compliance review of the Annual Report. In this regard, PNG-West suggests an informal review process would be appropriate, ideally completed within 30 days of submission, such that the review process would not hold up planned capital activities. On completion, as evidence of the review, PNG-West proposes the BCUC provides PNG-West with a letter stating acceptance of the Capital Report. [210]

PNG-West submits that the report is not being provided to the BCUC as a request for approval, but rather for informational purposes and therefore does not consider the timing of the report submission to be linked to the approval to proceed with capital expenditures. PNG-West notes that the BCUC approval will be required for individual significant capital projects through its revenue requirements, CPCN or other applications.[211]

Minimum Dollar Threshold for CPCN filings

PNG-West responded to IRs with respect to possible CPCN filing thresholds and noted that it has historically made use of an informal threshold of $1,000,000 as a general guideline. However, based on a cursory review of other utilities under the BCUC's jurisdiction, PNG-West notes the threshold may be low and recommends a higher CPCN threshold between $1,500,000 to $2,000,000 be considered.[212] PNG-West submits that between 2015 to 2019, the proposed higher threshold would reduce the regulatory burden on PNG-West, effectively requiring six to seven CPCNs during this time period compared to nine CPCNs that would have been required at the $1,000,000 threshold.[213]

---

[207] Exhibit B-2, Section 3.4.1.1, p. 154; Exhibit B-3, BCUC IR 79.1, 79.2.1.
[208] Exhibit B-3, BCUC IR 79.1.
[209] Exhibit B-2, Section 3.4.1.1, pp. 153 and 156.
[210] Ibid., p. 156.
[211] Exhibit B-3, BCUC IR 81.2.
[212] Ibid., BCUC IR 79.7.2.
[213] Ibid.

Position of the Parties

BCOAPO does not take a position on the proposal for reporting on significant capital projects or on the proposed minimum dollar threshold for filing future CPCN applications.

Panel Determination

The Panel acknowledges that PNG-West has satisfied the direction pursuant to Order G-151-18[214] and directs PNG-West to file a report on significant capital projects annually as part of its Annual Report on or before April 30, including but not limited to the following information:

- **Reporting of all non-recurring capital projects with total costs of $500,000 or more, including the following details:**
    - **a description of the project;**
    - **type of project;**
    - **level of accuracy for the cost estimate (AACE estimate class);**
    - **actual and forecast costs to completion, broken down by year;**
    - **estimated construction commencement date; and**
    - **confirmation of intention to file a CPCN application or a UCA section 44.2 expenditure schedule, as appropriate.**

Planned capital expenditures filed under section 45 of the UCA are assessed by the BCUC in the context of public convenience and necessity. To be efficient and effective, the BCUC must be provided with relevant information in a timely manner and in sufficient detail to facilitate review of the capital expenditures. The annual reporting on significant capital expenditures provides an orderly approach to allow PNG-West's future capital expenditures to be considered in advance of construction and provides the BCUC with an opportunity to identify forecast extension projects that may warrant a CPCN filing under section 45(2) of the UCA.

The Panel approves the form of the annual Capital Report proposed by PNG-West, including the level of detail and finds the proposed format, along with the focus on planned non-recurring capital expenditures to be reasonable. The Panel concurs that planned recurring projects typically are not system extensions, new facilities and significant system modifications or additions and accordingly would not necessitate inclusion in the Capital Report. Where there are capital projects that are required to address unanticipated risks, customer requirements, or urgent needs, the Panel accepts that depending on timing, these projects may not be included in the Capital Report prior to construction starting. However, the Panel considers it appropriate that PNG-West notify the BCUC of these projects in order to allow the BCUC to consider them in advance of construction. **Accordingly, for any non-recurring capital projects with total costs of $500,000 or more that are not included in the annual Capital Report due to timing considerations, the Panel directs PNG-West to file the following details with the BCUC at least 30 days before construction commences:**

- **a description of the project;**
- **type of project;**
- **level of accuracy for the cost estimate (AACE estimate class);**

[214] Order G-151-18, Directive 5.

- **actual and forecast costs to completion, broken down by year;**
- **estimated construction commencement date; and**
- **confirmation of intention to file a CPCN application or a UCA section 44.2 expenditure schedule, as appropriate.**

The Panel finds PNG-West's proposed total capital project expenditure of $500,000 to be appropriate for the annual Capital Report. The threshold results in the appropriate balance between prospective oversight of capital projects and regulatory efficiency. The Panel agrees any reduction in the threshold could result in an increased cost and resource requirement to both the BCUC and PNG.

The Panel is satisfied with including the Capital Report as an element of PNG-West's Annual Report and accepts this as an efficient and pragmatic approach that reduces regulatory and administrative burden for both PNG-West and the BCUC while eliminating the need to have multiple reports with multiple deadlines to track. Any BCUC acknowledgement notice in response to such filing should not be considered as approval of the capital expenditures included in the Capital Report or that a CPCN or prudency review cannot be directed in the future.

The Panel recognizes that a minimum dollar threshold for CPCNs allows the BCUC the opportunity to undertake a prospective public interest review of future construction of extensions and new facilities as well as any significant system modifications or additions that are planned over the filing threshold. The Panel agrees with PNG-West that the current $1,000,000 informal threshold may be too low and may not offer the most efficient regulatory review of capital projects, considering this may include projects with lower cost, limited complexity and negligible impact with respect to public interest.

While regulatory certainty is desirable, the Panel is reluctant to establish a formal threshold for CPCN applications as there may be instances where a capital project entailing a lower dollar value may nonetheless have a unique public interest component which warrants review. In such cases, the BCUC must have the flexibility to examine the need, rationale and costs of such projects. Accordingly, while not directing PNG-West to do so, the Panel considers that PNG-West's proposed CPCN filing threshold of $1.5 million or above for capital projects that require a CPCN to be reasonable, as the BCUC would have an interest in reviewing projects of this magnitude on a prospective basis. The Panel also encourages PNG-West to consider this same threshold for its section 44.2 UCA expenditure schedule filings. Further, regardless of any formal CPCN filing threshold level, it does not preclude the BCUC from exercising its jurisdiction under section 45(5) of the UCA to require a CPCN for extensions, irrespective of the forecast cost, if it considers this to be warranted. The Panel further notes that the BCUC can review the balance of capital projects in an RRA or subsequently in a prudency review.

5.0 Deferral Accounts

5.1 Handling of UAF Gas Losses

The American Gas Association defines 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.[215]

PNG-West requests approval to increase both the UAF component of Company Use gas from 0.0 to 1.0 percent and the UAF Volume deferral account loss cap from 1.0 to 1.5 percent.[216] PNG-West has a UAF Volume deferral account and the deferral account amounts are recovered from or refunded to customers via the Gas Cost Variance Account (GCVA) Company Use rider. Changes to the GCVA Company Use rider are proposed and approved as part of the BCUC's review of PNG-West's quarterly reporting on gas supply costs. BCUC approval is required to record any UAF amounts greater than the loss cap in the deferral account.

PNG-West identifies four "primary drivers" that account for approximately 1.13 percent of UAF volumes: blowdown and venting estimate error, measurement error, linepack error and accrual error, with the accrual error accounting for the majority at 0.88 percent. PNG-West states that an analysis of these primary drivers indicates the "theoretical minimum average UAF that PNG-West can be expected to achieve" and supports the increase to the UAF Volume deferral account loss cap to 1.5 percent.[217] Table 8 below provides a comparison of these primary drivers in 2019 as compared to 2009:[218]

Table 8: Comparison of Primary Drivers

	2019 Analysis		2009 Analysis	
	Magnitude (GJ)	Portion of Deliveries	Magnitude (GJ)	Portion of Deliveries
Measurement Error	4,445	0.10%	5,867	0.09%
Blowdown and Venting Estimate Error	1,166	0.03%	2,655	0.04%
Linepack Error	5,971	0.13%	17,995	0.27%
Unbilled Estimate Error	40,210	0.88%	18,128	0.27%
Total	**51,793**	**1.13%**	**44,645**	**0.67%**
Requested Limit*	**68,622**	**1.50%**	**66,452**	**1.00%**
Deliveries	4,574,801		6,645,157	

* Volumetric limit is illustrative only, based on deliveries in 2008 and 2018, respectively

Historically PNG-West experienced offsetting UAF gains and losses, which meant that setting the UAF component of Company Use gas at 0 percent was reasonable. However, between 2015 and 2019 the average net UAF losses experienced by PNG-West were 1.88 percent of deliveries. Historical UAF losses for each year between 2004 and 2019 as well as the available months in 2020 are summarized in tables 9 and 10 below:[219]

---

215 https://www.aga.org/natural-gas/glossary/u/
216 Exhibit B-2, p. 29.
217 Ibid., pp. 29-30.
218 Exhibit B-3, BCUC IR 6.10.
219 Ibid., BCUC IR 6.3; Exhibit B-7, BCUC IR 93.3.

Table 9: Historical UAF Losses

		2004	2005	2006	2007	2008	2009	2010	2011
Deliveries	GJ	33,705,691	27,703,800	6,982,442	7,624,889	6,645,159	6,178,233	4,197,090	4,121,976
UAF gains/(losses)	GJ	138,224	202,128	(21,946)	(2,233)	(61,996)	11,801	61,377	(93,287)
UAF as a portion of deliveries	%	0.41%	0.73%	-0.31%	-0.03%	-0.93%	0.19%	1.46%	-2.26%
Commodity Cost of Gas	$/GJ	$ 5.53	$ 7.48	$ 7.39	$ 7.40	$ 7.44	$ 7.40	$ 7.39	$ 4.77
Value of UAF gains/(losses)	$	$ 764,240	$ 1,511,310	$ (162,091)	$ (16,520)	$ (460,999)	$ 87,314	$ 453,330	$ (444,981)
		2012	2013	2014	2015	2016	2017	2018	2019
Deliveries	GJ	4,053,583	3,799,510	3,976,663	4,115,752	4,327,115	4,908,506	4,552,276	5,065,215
UAF gains/(losses)	GJ	(4,802)	30,385	47,032	1,647	(226,552)	(20,122)	(75,992)	(107,812)
UAF as a portion of deliveries	%	-0.12%	0.80%	1.18%	0.04%	-5.24%	-0.41%	-1.67%	-2.13%
Commodity Cost of Gas	$/GJ	$ 3.65	$ 3.24	$ 3.25	$ 3.57	$ 1.93	$ 2.39	$ 1.53	$ 1.38
Value of UAF gains/(losses)	$	$ (17,508)	$ 98,508	$ 152,995	$ 5,876	$ (436,565)	$ (48,052)	$ (116,191)	$ (148,457)

Table 10: UAF Losses in 2020

2020	January	February	March	April	Total
Actual UAF Gains/(Losses)	(38,898)	(15,574)	(33,724)	27,124	(61,072)
Deliveries	629,335	519,404	522,323	419,802	2,090,865
UAF Gains/(Losses) as a portion of deliveries	-6.2%	-3.0%	-6.5%	6.5%	-2.9%
Value of UAF Gains(Losses)	$ (70,912)	$ (28,392)	$ (61,479)	$ 49,448	$ (111,334)

The average UAF losses experienced by PNG-West during the 2015 to 2019 timeframe is higher than selected Canadian natural gas distribution utilities, as indicated by table 11 below:[220]

Table 11: UAF Losses - Canadian Natural Gas Distribution Utilities

	Notes	2015	2016	2017	2018	2019	Average
Heritage Gas					1.02%	1.01%	1.02%
AltaGas Utilities	Rider H	1.28%	0.89%	1.05%	0.96%	1.37%	1.11%
ATCO	Rider D		0.57%	0.83%	1.02%		0.80%
Enbridge Gas Distribution	Forecast				0.99%		0.99%
FortisBC	Average of 2010 - 2015	0.59%					0.59%
Pacific Northern Gas Ltd.		-0.04%	5.24%	0.41%	1.67%	2.13%	1.88%
Pacific Northern Gas (N.E.) Ltd.		1.03%	5.30%	-0.13%	1.41%	2.17%	1.96%

PNG-West has not identified any changes that have caused only monthly UAF losses beginning in 2015[221] and specifically, it has not been able to identify the specific cause of the UAF losses in 2019. Accordingly, PNG-West is currently undergoing an in-depth review of all metered data, data conversion factors and physical changes at custody transfer receipt points, focused on the specific cause or causes of UAF losses in 2019. PNG-West provides additional details of the ongoing review of UAF as follows:

[220] Exhibit B-3, BCUC IR 6.2.
[221] Exhibit B-7, BCUC IR 93.8.

> Included in the review is an examination of: (i) the spreadsheets used to calculate the UAF volumes; (ii) PNG's volume accounting and billing system; (iii) the estimate of unbilled consumption to the end of the calendar month, of the residential and small commercial classes (the "unbilled estimates"); (iv) the gas volumes reporting processes at Enbridge, specifically, the application of unit conversions and heating values in the conversion of metered volumes to units of gigajoules, and the reporting of both volume and energy on Enbridge's statement of deliveries; and (v) deliveries to the large commercial, industrial and transport customers for any deviations from expected trends.
>
> Depending on its findings, PNG may initiate a review of its measurement facilities at its large customer sites and at Enbridge's custody transfer meter facilities delivering gas onto the PNG-West system. The focus of this review would be to verify the appropriateness and correctness of the field equipment, equipment configurations and volume calculations.[222]

PNG-West proposes to submit its findings to the BCUC in the third quarter of 2020 and states that it does not have concerns with the BCUC deferring a final determination on the proposed changes to the UAF component of Company Use gas and the loss cap until PNG-West's review is complete.[223]

Positions of the Parties

BCOAPO opposes the increase to the UAF Volume deferral account loss cap and highlights the UAF losses experienced between 2016 and 2019 and in January to March 2020, all of which have been to the account of PNG-West's customers. Further, BCOAPO expects the UAF losses attributable to the four primary drivers identified by PNG-West to be immaterial or net to zero. Specifically, BCOAPO states that "given the standards set for custody transfer meters including calibration and testing, in BCOAPO's view a reasonable expectation is that meter variances would not account for any significant UAF." BCOAPO submits that the shareholder should bear all the UAF risk but, at a minimum, recommends that the shareholder "bears sufficient UAF risk to incent minimizing UAF variances." If the BCUC determines that the shareholder should bear no UAF risk, BCOAPO recommends that a determination on the changes to UAF be deferred until PNG-West has filed its findings from the review of UAF.[224]

In reply, PNG-West states that it has provided extensive evidence to support the proposed changes but reiterates that it is amenable to deferring BCUC approval of the requested changes until the BCUC has reviewed its report on the data and calculations impacting monthly UAF volumes.[225]

Panel Determination

The Panel directs PNG-West to file a report with the BCUC detailing the results of its review of 2019 UAF losses by December 31, 2020, and include the following information:

- **Analysis of the identified factors contributing the 2019 UAF losses, including the following:**
    - **Whether these factors are related to isolated events or errors or whether they are due to systemic issues that are expected to contribute to UAF losses on an ongoing basis;**

[222] Exhibit B-3, BCUC IR 6.1, Exhibit B-7, BCUC IR 93.6.
[223] Exhibit B-7, BCUC IR 93.2 and 93.4.
[224] BCOAPO Final Argument, pp. 5-10.
[225] PNG-West Reply Argument, p. 3.

- Whether the UAF losses experienced in 2019 for each factor are expected to reverse in future and if not, why not; and
    - **Analysis of the unbilled estimate error, including any detailed explanation as to why this factor does not result in both UAF gains and losses.**
- **Any actions being undertaken by PNG-West to mitigate UAF losses.**
- **If PNG(NE) is included as part of the review undertaken by PNG, any results that are available for PNG(NE).**

The Panel recognizes that historically between 2004 and 2014 PNG-West experienced offsetting UAF gains and losses; however, between 2015 and 2019 PNG-West has recorded UAF losses. While PNG-West has identified four "primary" drivers of UAF losses, with the majority being attributable to accrual error accounting, PNG-West has not identified any changes that have caused only monthly UAF losses beginning in 2015[226] and specifically, it has not been able to identify the specific cause of the UAF losses in 2019. Accordingly, the utility is currently undertaking an extensive review of the reasons for the 2019 UAF losses.

The Panel has several concerns regarding the proposal to increase both the UAF component of company use gas and the loss cap for the UAF deferral account before a review of the 2019 UAF losses is completed by PNG-West. With respect to accrual error accounting, the Panel expects that UAF related to this factor would reverse and ultimately result in both UAF gains and losses. However, PNG-West identifies accrual error accounting as one of the primary drivers that is contributing to 0.88 percent of UAF losses. Further, as indicated in the table provided in response to BCUC IR 1.6.10, the unbilled estimate error has increased from 0.27 percent of deliveries in 2009 to 1.13 percent of deliveries in 2019. In addition, the Panel notes that PNG-West's UAF losses are higher than selected Canadian natural gas utilities on average between 2015 and 2019.[227]

Given the concerns identified by the Panel above with respect to UAF losses, the Panel considers that additional evidence is required to support any determination on PNG-West's request for approval to increase the UAF component of Company Use gas from 0 percent to 1 percent and the loss cap for the UAF deferral account from 1.0 percent to 1.5 percent. The Panel considers that any determinations on these matters would benefit from the results of the PNG-West review of 2019 UAF losses, expected to be completed by third quarter 2020**.**

The Panel also notes BCOAPO's recommendation that the PNG-West shareholder should bear all of the UAF risk or, at a minimum, "sufficient UAF risk to incent minimizing UAF variances." Given the Panel's findings above, the Panel considers it more appropriate for the BCUC to address this matter, as necessary, after the results of the PNG-West review of 2019 UAF losses are filed.

5.2 Transfer Pricing Deferral Account

As noted in Section 1.2, PNG is part of a group of Canadian utilities and renewable power entities owned by TSU and forecast costs in test years 2020 and 2021 have been established based on the assumption that 20 percent of PNG's President's time and 30 percent of PNG's Director of Business Development's time will be spent on non-regulated activities. [228]

[226] Exhibit B-7, BCUC IR 93.8.
[227] Exhibit B-3, BCUC IR 6.2.
[228] Exhibit B-2, Section 2.5.7.2, p. 65; Exhibit B-3, BCUC IR 35.4.

In accordance with PNG's Inter-Affiliate Code of Conduct (COC) approved under BCUC Order G-270-19, PNG employees working on non-regulated activities track their time ensuring that PNG receives adequate compensation for services provided to its affiliates and thereby protecting PNG's ratepayers from subsidizing activities that are not related to PNG's regulated services. [229]

PNG expects that the actual amount of time PNG's President and Director of Business Development will each spend on non-regulated activities may vary based on the requirements for the work performed, and therefore proposes that any variances between actual and forecast amounts be recorded in a one-year interest bearing Transfer Pricing deferral account commencing in test year 2020 and continue for future years.[230] PNG proposes a one-year amortization period and with consideration to the fact that PNG has been filing two-year revenue requirements applications, PNG proposes to seek immediate amortization in each revenue requirement test year beginning in 2022.[231]

PNG submits that a Non-Regulated Business Recoveries account was previously established under Order G-13-12 following the acquisition of PNG by AltaGas Ltd. and under Order G-131-16, PNG had received approval to dissolve the deferral account as no employees were participating in any non-regulated activities on behalf of any affiliated companies. However, with the formation of TSU and the greater collaboration amongst the various affiliated utilities, as well as the greater potential to explore non-regulated activities, PNG anticipates that there will be a greater level of non-regulated activities specifically performed by PNG's President and Director of Business Development.[232]

Positions of the Parties

While acknowledging PNG's request for approval to re-instate a one-year interest bearing Transfer Pricing deferral account to track differences between forecast and actual utility charges to non-regulated services or activities, BCOAPO does not take a position on PNG's proposal.[233]

Panel Determination

The Panel approves a Transfer Pricing deferral account bearing interest at PNG's short term interest rate to record the difference between forecast and actual utility charges to non-regulated services or activities which is to be amortized over one year of the revenue requirement test period. This takes into consideration the uncertainty regarding PNG's level of non-regulated business activity under its new owner TSU.

5.3 Accelerated CCA Deferral Account

As part of the Government of Canada's 2018 Fall Economic Statement tabled on November 21, 2018, a new Accelerated Investment Incentive was enacted to allow Canadian businesses to accelerate CCA deductions for assets purchased after November 20, 2018. The Accelerated Investment Incentive allows certain capital property that is subject to the general CCA rules to be eligible for an enhanced first-year allowance equal to three times the normal first-year tax depreciation deduction that would otherwise apply in the year the asset is available for use. This large deduction in the first year would ultimately result in lower tax deductions in future

[229] Ibid., p. 65.
[230] Ibid., p. 65; Exhibit B-3, BCUC IR 35.4.
[231] Exhibit B-3, BCUC IR 35.5.
[232] Ibid., BCUC IR 35.4.
[233] BCOAPO Final Argument, pp. 2, 13.

years. PNG-West has utilized the accelerated CCA provision for 2019 and has recorded its impact, calculated to be $176,000, in a short-term interest deferral account. PNG-West requests approval for the proposed Accelerated CCA deferral account, as well as to fully amortize the balance in test year 2020 and to subsequently eliminate the account once the balance is fully amortized.[234]

Position of the Parties

BCOAPO accepts PNG-West's proposal as filed for the Accelerated CCA deferral account.[235]

Panel Determination

The Panel approves PNG-West's proposal to establish an Accelerated CCA deferral account bearing interest at PNG-West's short term interest rate and to record the Accelerated CCA provision for 2019 of $176,000, to fully amortize the balance in test year 2020 and to subsequently eliminate the deferral account. The Panel accepts that PNG-West's proposed deferral account is reasonable and will benefit ratepayers by mitigating cost of service increases in 2020.

5.4 PLP Project Amendment Sharing Deferral Account

In September 2016, PNG-West and Triton LNG Limited Partnership entered into an amending agreement to revise the terms of the Transportation Reservation Agreement dated July 2013 for the proposed PLP Project (Amending Agreement). Upon execution of the Amending Agreement, PNG-West recovered all the development costs incurred on the PLP project and recognized revenues of approximately $6.8 million related to the recovery of overhead and carrying costs. Pursuant to Order G-151-18, the BCUC approved PNG-West's proposal to have $200,000 of the revenues recognized shared with PNG-West's customers. Accordingly, $200,000 was recorded in an interest bearing deferral account and fully amortized in 2019. As the deferral account was established for a specific purpose and is no longer required, PNG-West proposes the PLP Project Amendment Sharing deferral account be eliminated.[236]

Position of the Parties

BCOAPO accepts PNG-West's proposal to eliminate the PLP Project Amendment Sharing deferral account.[237]

Panel Determination

The Panel approves PNG-West's request to close the PLP Project Amendment Sharing deferral account on the basis that having served its specific purpose with a $nil balance currently, it is no longer required. The Panel acknowledges the PLP Project Amendment Sharing deferral account has fulfilled its purpose and has a $nil balance at the end of fiscal 2019.

5.5 RECAP Deferral Account

PNG-West proposes in its Final Argument to include the new RECAP Development Cost deferral account in its final regulatory schedules and record RECAP development costs of $725,000 in 2020 and $275,000 in 2021.[238]

[234] Exhibit B-2, Section 2.9, pp. 76-77.
[235] BCOAPO Final Argument, p. 13.
[236] Exhibit B-2, Section 2.9, pp. 78-79.
[237] BCOAPO Final Argument, p. 13.
[238] PNG-West Final Argument, Section 14.4, p. 26; PNG-West Supplemental Final Argument (dated July 2, 2020), Section 2.2, p. 3.

Order G-35-20 approved the new rate base deferral account to record up to $1 million of development, permitting and consultation expenses related to the Reactivation Project.

PNG-West filed a breakdown of the $1 million deferral account additions for each of 2020 and 2021 and by cost category, including FEED/Engineering and planning, permitting, survey, lands, indigenous nations consultation and project services. [239] Further, PNG-West submits that it has received several bids with a total requested volume of 163.0 MMSCFD for delivery to the Prince Rupert, Terrace and Kitimat interconnection locations.[240]

Panel Determination

The Panel approves the additions of $725,000 in 2020 and $275,000 in 2021 to the existing RECAP Development Cost rate base deferral account. The deferral account itself was approved by Order G-35-20 to record up to $1 million of development, permitting and consultation expenses. The Panel has reviewed the cost breakdown of the additions by year and finds that the additions are consistent with the type and amount of additions approved by Order G-35-20 and are consistent with PNG-West's receipt of several bids with a total requested volume of 163.0 MMSCFD in response to the RECAP.

6.0 Other Matters

6.1 Rate Smoothing Proposal

PNG-West proposes the following approach to smooth delivery rate increases over the Test Period:[241]

1. Make the 2020 interim delivery rates approved by Order G-330-19A permanent.

   Based on the evidence in this proceeding, the indicated permanent 2020 delivery rates are lower than the interim delivery rates. For example, Order G-330-19A approved an interim residential delivery rate increase of 2.3 percent. However, based on the Application and adjustments/corrections, there is now an indicated 2020 permanent residential delivery rate decrease of approximately 0.2 percent and a 2021 rate increase of 3.9 percent.[242] Accordingly, if the indicated permanent residential delivery rate decrease of 0.2 percent is implemented, a rate rider to refund the difference between the interim and permanent 2020 delivery rates will be required for the latter months of 2020 and a delivery rate increase of 3.9 percent will be required January 1, 2021.

2. Amortize $nil in 2020 and $2,370,000 in 2021 in the LNG Partners Option Fee Payment deferral account. This results in a balance at December 31, 2021 available to offset rate increases in future years of $2,670,000. As comparison, the balance remaining at December 31, 2021 under PNG-West's original proposal is $1,378,000.[243]

   The BCUC approved the establishment of the LNG Partners Option Fee Payment deferral account pursuant to Order G-174-08 to record option fee payments received from customers wishing to secure future transportation capacity on PNG-West's system. In past RRAs, PNG-West has credited (i.e. amortized) amounts in the deferral accounts to all customers as a mechanism to reduce revenue deficiencies and offset rate increases.

[239] Exhibit B-12, BCUC IR 2.2 on Evidentiary Update.
[240] Exhibit B-9, Panel IR 1.1
[241] PNG-West Supplemental Final Argument dated July 2, 2020, p. 3.
[242] Exhibit B-2-2, pp. 3-4.
[243] Exhibit B-2, Tab 2, p. 20.

3. Use the rate deferral mechanism whereby $824,000 of the 2020 revenue sufficiency is placed in a short-term interest deferral account and amortized in 2021.

PNG-West's proposed rate smoothing approach as outlined above, subject to the determinations in these reasons, results in an increase to average delivery rates of approximately 2.0 percent in 2020 (i.e. equivalent to the 2020 interim rate increase) and approximately 1.9 percent in 2021.[244]

PNG-West states that this approach has several advantages, including maintaining delivery rates increases at inflationary levels and leaving a balance in the LNG Partners Option Fee deferral account to offset rate increases in future years. Further, this proposal minimizes rate fluctuations and does not require a rate rider to refund the difference between interim and permanent rates for 2020.[245]

Position of the Parties

BCOAPO states that it accepts the amortization of the LNG Partners Option Fee deferral account, as filed.

Panel Determination

The Panel approves PNG-West's proposed rate smoothing approach, including the following:

- **Making permanent the 2020 interim delivery rates approved by Order G-330-19A:**
- **Amortizing the LNG Partners Option Fee Payment deferral account of $nil in 2020 and $2,370,000 in 2021; and**
- **Using the rate deferral mechanism whereby $824,000 of the 2020 revenue sufficiency is deposited into a short-term interest deferral account and amortized in 2021.**

The Panel agrees that PNG-West's rate smoothing proposal has several benefits, including providing customers with rate stability over the Test Period and leaving a balance of $2,670,000 in the LNG Partners Option Fee Payment deferral account to offset potential rate increases in future years in accordance with its original intent. Accordingly, the Panel finds that PNG-West's proposed approach is reasonable.

6.2 Impact of COVID-19 Pandemic

During the IR process, PNG-West was asked to address the impact of COVID-19 on the Test Period forecast revenue requirements. In response, PNG-West indicates that it does not have any evidence to support a substantial impact to gas consumption and notes that mechanisms are in place to capture use per account variances related to residential and small commercial customers and load variances for some of the large industrial customers.[246] In addition, PNG-West does not anticipate the pandemic having a material impact on the timing of any IT projects or new staff position start dates.[247] Finally, apart from PNG-West being notified by the customer that the LNG Canada Let Down Station #1 (LDS#1) will not likely be required until 2022 as a result of a project delay on the customer side, PNG-West did not identify any impact on PNG-West's capital plan.[248]

---

[244] PNG-West Supplemental Final Argument dated July 2, 2020, p. 3
[245] Exhibit B-12, Panel IR 4.5
[246] Exhibit B-7, BCUC IR 90.3
[247] Ibid., BCUC IR 90.1.1
[248] Ibid., BCUC IR 119.2

Notwithstanding the removal of the capital costs associated with the LDS#1 at the customer's request, PNG-West does not anticipate any significant revisions to the forecasts included in the Application.[249]

PNG-West notes that despite the COVID-19 increasing uncertainty in the capital markets, PNG-West is not yet in a position to quantify the extent of investor return expectations for entities similar in risk to itself. Further, PNG-West submitted that should the BCUC conclude that PNG-West's cost of capital requires review due to the impact of COVID-19, consistent with historical practice, PNG-West expects the BCUC to commence a separate hearing process for that purpose.[250]

PNG-West filed a separate application with the BCUC for approval of the creation of a COVID-19 deferral account to capture unrecovered revenues and unplanned costs and cost savings arising from the COVID-19 pandemic. The BCUC provided approval of that application by Order G-146-20 dated June 10, 2020.[251]

Positions of the Parties

In BCOAPO's Final Argument, it notes that while other business have been absorbing the impacts of the COVID-19 pandemic, the BCUC approved COVID-19 deferral account holds the shareholders essentially harmless and allows the utility an opportunity to earn its approved after tax return on equity throughout the pandemic.[252]

In reply, PNG-West observes that it has provided its view on this matter in response to BCOAPO's information requests.[253]

Panel Discussion

The Panel has reviewed the evidence to support PNG-West's Test Period revenue requirements and notes that there is no evidence to support changes to the forecasts in view of the COVID-19 pandemic at this time. Further, the Panel acknowledges that PNG-West established forecast variance deferral accounts, including the COVID-19 deferral account which records unrecovered revenues and unplanned costs and savings arising from the COVID-19 pandemic, are not biased towards either the shareholder or ratepayer. These deferral accounts capture variances between forecast and actual costs and/or revenues and may result in either a refund to or recovery from ratepayers.

The Panel notes BCOAPO's concerns raised with respect to PNG-West's current risk premium and recognizes that as directed by Order G-47-14 PNG-West includes an updated business risk assessment as part of its RRAs. This allows the Panel to determine if there have been any significant changes to the circumstances faced by the utility with respect to the level of business risk. We not persuaded that there is sufficient evidence to suggest a change to PNG-West's current risk premium is warranted at this time.

6.3 PNG-West and PNG(NE) Rate Design

After reviewing the evidence in this proceeding, in conjunction with that in the PNG(NE) Proceeding, the Panel has observed the following in the current Test Period as compared to the previous test period:

[249] Exhibit B-5, BCOAPO IR 1.1; Exhibit B-7, BCOAPO IR 13.1.
[250] Exhibit B-8, BCOAPO IR 13.1.
[251] Exhibit B-5, BCOAPO IR 1.2.
[252] BCOAPO Final Argument, p. 10.
[253] PNG-West Reply Argument, Section 2.1, p. 5 [IR referenced in PNG-West Reply: Exhibit B-8, BCOAPO IR 13.1].

- PNG-West and PNG(NE) are forecasting an increase in O&M costs[254] and capital expenditures;[255]
- The PNG-West system continues to experience unutilized capacity, which has persisted since the loss of its largest industrial customers, specifically Methanex Corporation in 2005 and West Fraser Mills Ltd. in 2010.[256] In addition, minimal load growth is expected;[257]
- The PNG(NE) FSJ/DC Division has experienced a decrease in overall throughput over the period of 2013-2016 with a declining trend residential use per account.[258] In the current Test Period, the PNG(NE) FSJ/DC Division is forecasting low or near zero load growth;[259] and
- The PNG(NE) TR Division faces a significant level of volatility, both in terms of customer count and overall throughput.[260] And apart from a forecast increase in load for the TR's Division only industrial customer, PNG(NE) is otherwise forecasting little or no growth over the Test Period for the region.[261]

These factors are concerning to the Panel, particularly given the BCUC's observations in the PNG(NE) 2018-2019 Decision:[262]

> 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 much 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…, 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 2 indicates that the TR natural gas use per customer has dropped significantly since 2013.

Given these concerns, the BCUC urged PNG(NE) at that time to consider options to the current rate design including postage stamp rates for its service areas:[263]

> 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

[254] Exhibit B-2, Section 2, pp. 17-18, Table 5 & 6; PNG(NE) Proceeding, Exhibit B-2 (FSJ/DC), Section 2, pp. 17-18, Table 7 & 8; Exhibit B-2 (TR), Section 2, pp. 17-18, Table 5 & 6
[255] Ibid., Section 2.13.1.1.1, p. 95, Table 38; Section 2.13.1.1.2, p. 104, Table 39; Section 3.2, p. 130, Table 45; PNG(NE) Proceeding, Exhibit B-2 (FSJ/DC) Section 2.13.1.1.1, p. 64, Table 31; Section 2.13.1.1.2, p. 72, Table 32; Section 3.2, p. 94, Table 38; Exhibit B-2 (TR) Section 2.13.1.1.1, p. 61, Table 28; Section 2.13.1.1.2, p. 63, Table 29; Section 3.2, p. 77, Table 36
PNG(NE) FSJ/DC and PNG(NE) TR: capital expenditures in test years 2020 and 2021 are greater than Decision 2019, however capital expenditures in test year 2021 is less than test year 2020.
[256] PNG and PNG(NE), Generic Cost of Capital Proceeding – Stage 2, Exhibit B-14, pp. 15-16.
[257] Exhibit B-2, Section 2.1, p. 23, Table 9; Exhibit B-2, Appendix C, p. 5.
[258] Ibid., Appendix C, p. 5.
[259] Exhibit B-3, BCUC IR 15.3.
[260] Exhibit B-2, Appendix C, p. 5.
[261] Exhibit B-3, BCUC IR 15.3.
[262] PNG(NE) 2018-2019 RRA Decision, p. 28.
[263] Ibid., p. 29.

> 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.

The evidence in this proceeding has raised similar concerns for the Panel. The Panel is concerned that despite the BCUC's urging in the PNG(NE) 2018-2019 Decision, there still does not appear to be any specific plan to address these ongoing challenges.

The Panel acknowledges PNG's statements that the potential, incremental volumes resulting from the RECAP will provide future benefits to PNG's ratepayers; however, the Panel notes that this does not apply to PNG(NE). In view of these circumstances, the Panel considers it may be in the best interests of both the shareholder and ratepayers for PNG to examine the long term plans of its utilities and the continued viability of their current rate design as part of the utilities' next RRAs. The Panel urges PNG to focus on the consideration and development of a comprehensive business strategy to address the current challenges, which may necessitate consideration of rate design changes including postage stamp rates and/or amalgamation of its various entities to reduce costs on a consolidated basis or produce greater operational efficiencies for the mutual benefit of ratepayers and the shareholder.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of October 2020.

Original signed by:

A. K. Fung, QC
Panel Chair / Commissioner

Original signed by:

C. Brewer
Commissioner

Original signed by:

M. Kresivo, QC
Commissioner

bcuc
British Columbia
Utilities Commission

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
bcuc.com

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

ORDER NUMBER
G-255-20

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

and

Pacific Northern Gas Ltd.
2020-2021 Revenue Requirements Application
for the PNG-West Division

BEFORE:
A. K. Fung, QC, Panel Chair
C. Brewer, Commissioner
M. Kresivo, QC, Commissioner

on October 14, 2020

ORDER

WHEREAS:

A. On November 29, 2019, Pacific Northern Gas Ltd. (PNG) filed its 2020-2021 Revenue Requirements Application (RRA) with the British Columbia Utilities Commission (BCUC) for the West Division (PNG-West) pursuant to sections 58 to 61, 89 and 90 of the *Utilities Commission Act* (UCA) (Original Application);

B. By Order G-330-19A, the BCUC approved PNG's delivery rates and Rate Stabilization Adjustment Mechanism (RSAM) on an interim and refundable/recoverable basis effective January 1, 2020, and established a regulatory timetable for the review of the Original Application, which included dates for intervener registration, filing an amended application, BCUC and intervener information requests (IR) No. 1 and 2, and PNG responses to IRs;

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.) participated as the sole intervener in the proceeding;

D. On February 28, 2020, PNG filed its amended application for approval of 2020 and 2021 (Test Period) delivery rates on a permanent basis (Application);

E. By Orders G-95-20, G-116-20 and BCUC letter dated June 2, 2020, the BCUC established the remainder of the regulatory process, including Panel IRs and written final and reply arguments;

F. On June 16, 2020, PNG filed an evidentiary update addressing two errors that pertain to the modelling of certain IT-related capital additions and income tax deductions that impact 2020 and 2021 delivery rates;

G. By Order G-158-20, the BCUC re-opened the evidentiary record and amended the regulatory timetable to include BCUC and intervener IRs on the evidentiary update and supplemental PNG final argument and revised dates for intervener and reply arguments;

H. On July 31, 2020, the BCUC re-opened the evidentiary record to issue Panel IR No. 2 and amended the regulatory timetable to request written supplementary final and reply arguments limited in scope to the matters related to Panel IR No. 2; and

I. The BCUC has considered the Application, evidence and submissions of the parties and makes the following determinations.

NOW THEREFORE pursuant to sections 58 to 61 of the UCA and for the reasons provided in the decision issued concurrently with this Order, the BCUC orders as follows:

1. PNG is approved to recover the 2020 revenue requirement and the resultant delivery rate changes on a permanent basis, effective January 1, 2020, as filed in the Application and subject to the following:
   - the adjustments identified by PNG during the regulatory process, as summarized in Appendix A to the decision issued concurrently with this Order; and
   - the directives and determinations outlined in this Order and the decision issued concurrently.
2. PNG is approved to recover on a permanent basis the 2020 RSAM rate rider set forth in the Application, effective January 1, 2020.
3. PNG is approved to recover the 2021 revenue requirement and the resultant delivery rate changes on a permanent basis, effective January 1, 2021, as filed in the Application and subject to the following:
   - the adjustments identified by PNG during the regulatory process, as summarized in Appendix A to the decision issued concurrently with this Order; and
   - the directives and determinations outlined in this Order and the decision issued concurrently.
4. PNG is approved to recover on a permanent basis the 2021 RSAM rate rider set forth in the Application, effective January 1, 2021.
5. PNG is approved to smooth rates over the Test Period in accordance with section 6.1 of the decision issued concurrently with this Order.
6. PNG is approved to capitalize costs arising from magnetic flux leakage in line inspection runs to BCUC Account 469 for depreciation over a ten-year period.
7. PNG is approved to recover total Shared Corporate Services Costs of $1.835 million in 2020 and $1.872 million in 2021 including the proposed allocation of costs between PNG-West and the Pacific Northern Gas N.E. Ltd. divisions using the allocation methodology previously approved by Order G-114-13.
8. PNG is approved to establish a new Shared Corporate Services Costs deferral account with a three-year amortization period and accruing interest at PNG's Weighted Average Cost of Debt and to record its portion of the consolidated Shared Corporate Services Costs of $676,000 in 2020 and $700,000 in 2021 in the deferral account.
9. PNG is directed to file annually a report on significant capital projects with total costs of $500,000 or more as part of its Annual Report on or before April 30, including but not limited to the information outlined in section 4.2 of the decision issued concurrently with this Order. For any capital projects that are required to be included in the report but are not included due to timing reasons, PNG is directed to file details of these projects at least 30 days before construction commences.
10. PNG is directed to update the interest rate forecasts in its final regulatory schedules to reflect the BMO March 2020 forecast interest rates.

11. PNG is directed to file a report with the BCUC detailing the results of its review of 2019 unaccounted for gas losses by December 31, 2020, including the information outlined in section 5.1 of the decision.
12. PNG is approved to re-instate a Transfer Pricing deferral account bearing interest at PNG's short term interest rate to record the difference between forecast and actual utility charges to non-regulated services or activities, which is to be amortized over one year of the revenue requirement test period.
13. PNG is approved to establish an Accelerated Capital Cost Allowance deferral account in accordance with section 5.3 of the decision.
14. PNG is approved to close the Triton Liquefied Natural Gas Project Amendment Sharing deferral account.
15. PNG is approved to record additions of $725,000 in 2020 and $275,000 in 2021 in the existing Reactivated Capacity Allocation Process Development Cost rate base deferral account.
16. PNG is directed to re-calculate the 2020 and 2021 revenue requirements and delivery rate changes reflecting the directives and determinations outlined in this Order and further described in the Decision issued concurrently and file revised regulatory schedules with the BCUC for endorsement within 30 days of this Order.
17. PNG is directed to file the following information in its next RRA:
    - a report detailing the information for specific IT projects outlined in section 2.1 of the decision; and
    - the updated Distribution Integrity Management and Transmission Integrity Management plans and a progress update regarding the Pipeline Segment by Segment Risk Assessment, the Aged Pipeline Condition Assessment and the Integrity Management Plan Audit as outlined in section 2.2 of the decision.
18. PNG is directed to collect from/refund to customers the difference between the interim and permanent 2020 RSAM rate rider at the average prime rate of PNG's principal bank for its most recent year.
19. PNG must inform all customers of permanent 2020 and 2021 delivery rates by way of written notice to be included with their next customer invoice after PNG's compliance filing has been accepted by the BCUC.
20. PNG is directed to comply with all other directives contained in the decision issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 14th day of October 2020.

BY ORDER

Original signed by:

A. K. Fung, QC
Commissioner

Pacific Northern Gas Ltd.
2020–2021 Revenue Requirements Application
for the PNG-West Division

SUMMARY OF ADJUSTMENTS AND CORRECTIONS

During the regulatory process, PNG-West identified the following adjustments to its Test Period revenue requirements that it proposes to reflect in its final regulatory schedules:[264]

Table 12: PNG-West – Summary of Adjustments / Corrections

Reference	Addressed in Final Argument Section	Subject	Type of Adjustment	2020 Impact on Revenue Deficiency	2021 Impact on Revenue Deficiency
BCUC IR 45.1; 114.1	12	Compressor Engine Overhaul Depreciation	Depreciation for 2020 and 2021 included in error and depreciation period corrected	$(68,000)	$(5,000)
BCUC IR 50.6	15.1.1.3	Salvus to Galloway Capital Costs	Update for capital information	(8,000)	50,000
BCUC IR 90.1; 119.2	15.1.3	LNG Canada LDS#1 Project	Remove capital project in 2020 and 2021 and related demand in 2021	25,000	231,000
BCUC IR 102.1.1	8.1 / 15.1.1.2	2020 Significant ILI Run	Proposed change in accounting treatment from O&M to capital	(1,150,000)	1,320,000
BCUC IR 103.2	8.2	New BCOGC Requests	Add new 2020 and 2021 O&M and capital for BCOGC costs	41,000	63,000
BCUC IR 114.1	15.1.5	Compressor Overhaul Costs	Reclassify capital costs from BCUC 469 to BCUC 466	80,000	(131,000)
BCUC Panel IR 2.2.1	15.1.1.3	Salvus to Galloway Development Costs	Remain as work in progress	(4,000)	(77,000)
RECAP Decision (Order G-35-20)	14.4	RECAP Development Costs	Record $1,000,000 of approved RECAP development costs to a deferral account	19,000	10,000
Exhibit B-2 Section 1.3	5 / 14.3	Option Fee Amortization	Revise amortization for maximum 2% rate increase	857,000	(1,474,000)
Net Impact Presented in Final Argument				**(208,000)**	**(13,000)**
Evidentiary Update	n/a	Correction of CCA and Plant Classification	Correct for higher CCA rate for IT projects and reclassify capital from BCUC 466/475 to BCUC 489	(615,000)	547,000
Revised Net Impact Provided in Evidentiary Update				**(823,000)**	**534,000**
Evidentiary Update BCUC IR 2.1	n/a	RECAP Development Costs	Revise forecasts between 2020 and 2021	4,000	(4,000)
Evidentiary Update BCUC IR 4.5	n/a	Option Fee Amortization	Revise amortization for 2021	-	1,051,000
Revised Net Impact before Rate Deferral Mechanism				**(819,000)**	**1,581,000**
Evidentiary Update BCUC IR 4.5		Rate Deferral Mechanism	Propose use of rate deferral mechanism	824,000	(1,682,000)
Revised Net Impact after Rate Deferral Mechanism				**$5,000**	**$(101,000)**

[264] PNG-West Supplemental Final Argument (July 2, 2020), Section 3, paragraph 19, p. 4.

Pacific Northern Gas Ltd.
2020–2021 Revenue Requirements Application
for the PNG-West Division

SUMMARY OF PROPOSED DELIVERY CHARGE RATE CHANGES

The table that follows summarizes the proposed 2020 and 2021 delivery rate changes, as filed for approval in the Application. The figures presented are subject to adjustments identified by PNG during the regulatory process, which are summarized in Appendix A of this decision, and the directives and determinations in this decision.[265]

Table 13: PNG-West – Summary of Proposed Delivery Charge Rate Changes

Customer Classification	Allocation of 2021 Revenue Sufficiency	Test Year 2021 Delivery Charge	Proposed Rate Change from 2020 to 2021		Allocation of 2020 Revenue Sufficiency	Test Year 2020 Delivery Charge	Proposed Rate Change from 2019 to 2020		Decision 2019 Delivery Charge
	$	$/GJ	$/GJ	%	$	$/GJ	$/GJ	%	$/GJ
Residential (Rate 1)	344,210	12.655	0.281	2.3%	336,806	12.374	0.276	2.3%	12.098
Granisle Propane	1,141	7.283	0.197	2.8%	1,147	7.086	0.193	2.8%	6.893
Commercial									
Small Commercial Firm (Rate 2)	163,019	10.643	0.226	2.2%	163,603	10.417	0.219	2.1%	10.198
Large Commercial Firm (Rate 3)	70,966	8.517	0.166	2.0%	36,220	8.350	0.164	2.0%	8.186
Small Comm Transport (Rate 22)	33,894	10.634	0.217	2.1%	33,177	10.417	0.219	2.1%	10.198
Large Comm Transport (Rate 33)	24,466	8.514	0.164	2.0%	23,972	8.350	0.164	2.0%	8.186
Commercial Interruptible (Rate 5)	4,422	5.195	0.105	2.1%	4,329	5.090	0.103	2.1%	4.987
Total Commercial	296,767				261,302				
Seasonal Off-Peak (Rate 6)	2,855	7.542	0.155	2.1%	2,797	7.387	0.152	2.1%	7.235
NGV (Rate 7)	0	3.350	-	0.0%	0	3.350	-	0.0%	3.350
Small Industrial									
Sales (Rate 4)	32,279	3.789	0.076	2.1%	31,881	3.713	0.075	2.1%	3.638
Transport	-	-	-	0.0%	-	-	-	0.0%	-
Interruptible Transport	45,068	3.3737	0.0669	2.0%	44,172	3.3069	0.0654	2.0%	3.2415
Total Small Industrial	77,347				76,053				
Large Industrial									
Rio Tinto Alcan									
Firm Transport	93,056	3.0720	0.0611	2.0%	91,228	3.0109	0.0597	2.0%	2.9512
Interruptible Transport	-	3.3737	0.0669	2.0%	-	3.3069	0.0654	2.0%	3.2415
Sub-total	93,056				91,228				
B.C. Hydro - Interruptible Transport	2,723	3.3737	0.0669	2.0%	2,666	3.3069	0.0654	2.0%	3.2415
Total Large Industrial	95,779				93,895				
TOTAL	**818,100**				**772,000**				

[265] Exhibit B-2, Section 1.4, p. 8, Table 2.

Pacific Northern Gas Ltd.
2020–2021 Revenue Requirements Application
for the PNG-West Division

Glossary and List of Acronyms

Acronym	Description
AACE	Association for the Advancement of Cost Engineering
ACI	AltaGas Canada Inc.
AltaGas	AltaGas Ltd.
Amending Agreement	PNG-West and Triton LNG Limited Partnership entered into an amending agreement to revise the terms of the Transportation Reservation Agreement dated July 2013 for the proposed Triton LNG Project (PLP Project)
ARM	Asset Record Modernization
ATRFB	Alberta Teachers’ Retirement Fund Board
BCOAPO	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
BCUC	British Columbia Utilities Commission
CCA	Capital Cost Allowance
CEO	Chief Executive Officer
CFO	Chief Financial Officer
CIS	Customer information services
CMMS	Computerized Maintenance Management System
COC	Code of Conduct
CPCN	Certification of public convenience and necessity
DC	Dawson Creek
EMAT	Electro-magnetic acoustic transducer
ERP	Enterprise Resource Planning
FortisBC	FortisBC Energy Inc.
FSJ	Fort St John
GCVA	Gas Cost Variance Account
GIS	Geographical Information System
GJ	gigajoules

Acronym	Description
HRIS	Human Resource Information System
ILI	In-line inspection
IMP	Integrity Management Program
IR	Information request
JDE	JD Edwards
KPMG	KPMG LLP
KPMG Report	An independent assessment of the Fair Value Estimate
LDS#1	LNG Canada Let Down Station #1
MFL	Magnetic flux leakage
O&M	Operations and maintenance
OGC	Oil and Gas Commission
OMA	Operating, maintenance and administrative and general
Original Application	Application seeks approval to amend its delivery rates and Revenue Stabilization Adjustment Mechanism on an interim and refundable/recoverable basis, effective January 1, 2020
PLP Project	Triton LNG Project
PNG	Pacific Northern Gas Ltd.
PNG(NE) 2018-2019 Decision	PNG(NE) 2018-2019 RRA Decision and accompanying Order G-164-18A
PNG(NE) Proceeding	PNG(NE) 2020-2021 RRA proceeding
PNG(NE)	Pacific Northern Gas (N.E.) Ltd.
PNG-West 2018-2019 Decision	PNG-West 2018-2019 RRA Decision and accompanying Order G-151-18
PSPIB	Public Sector Pension Investment Board
RECAP	Reactivated Capacity Allocation Process
ROW	Right-of-way
RRA	Revenue requirements application
RSAM	Revenue Stabilization Adjustment Mechanism
Test Period	Fiscal years 2020 and 2021
TR	Tumbler Ridge
TSU	TriSummit Utilities Inc.
UAF	Unaccounted for gas

Acronym	Description
UCA	*Utilities Commission Act*
UltiPro	Ultimate Software
US GAAP	US Generally Accepted Accounting Principles

Pacific Northern Gas Ltd.
2020–2021 Revenue Requirements Application
for the PNG-West Division

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 5, 2019 – Appointing the Panel for the review of Pacific Northern Gas Ltd. (West) Application dated November 29, 2019 for 2020-2021 Revenue Requirements
A-2	Exhibit removed and replaced by Exhibit A-2-1
A-2-1	Letter dated January 14, 2020 – Amended BCUC Order G-330-19A establishing the preliminary regulatory timetable for the review of the Application
A-3	Letter dated March 23, 2020 – BCUC Information Request No. 1 to PNG
A-4	**CONFIDENTIAL** Letter dated March 23, 2020 – BCUC Confidential Information Request No. 1 to PNG
A-5	Letter dated April 27, 2020 – BCUC Order G-95-20 together with the regulatory timetable
A-6	Letter dated May 1, 2020 – BCUC Information Request No. 2 to PNG
A-7	Letter dated May 19, 2020 – BCUC Order G-116-20 amending the regulatory timetable
A-8	Letter dated June 2, 2020 – Panel Information Request No. 1 to PNG
A-9	**CONFIDENTIAL** Letter dated June 2, 2020 – Panel confidential Information Request No. 1 to PNG
A-10	Letter dated June 18, 2020 – BCUC Order G-158-20 reopening the Evidentiary Record and establishing a Regulatory Timetable
A-11	Letter dated June 24, 2020 – BCUC Information Request No. 1 to PNG on the Evidentiary Update
A-12	Letter dated July 31, 2020 – Panel Information Request No. 2 to PNG

APPLICANT DOCUMENTS

B-1	**PACIFIC NORTHERN GAS LTD. WEST DIVISION (PNG-WEST)** Application dated November 29, 2019 for 2020-2021 Revenue Requirements
B-1-1	**CONFIDENTIAL** Letter dated November 29, 2019 – PNG 2020-2021 Revenue Requirements Application Confidential Appendix D
B-2	Letter dated February 28, 2020 – PNG Submitting Amended 2020-2021 Revenue Requirements Application
B-2-1	**CONFIDENTIAL** - Letter dated February 28, 2020 – PNG Submitting Amended 2020-2021 Revenue Requirements Application Confidential Appendix D
B-2-2	Letter dated June 16, 2020 – PNG Submitting Notification of Error in Amended 2020-2021 Revenue Requirements Application
B-3	Letter dated April 15, 2020 – PNG Response to BCUC Information Request No. 1
B-4	**CONFIDENTIAL** Letter dated April 15, 2020 – PNG Response to confidential BCUC Information Request No. 1
B-5	Letter dated April 15, 2020 – PNG Response to BCOAPO Information Request No. 1
B-6	Letter dated May 15, 2020 – PNG Submitting Request to Amend Regulatory Timetable
B-7	Letter dated May 20, 2020 – PNG Response to BCUC Information Request No. 2
B-7-1	**CONFIDENTIAL** Letter dated May 20, 2020 – PNG confidential Response to BCUC Information Request No. 2
B-7-2	Letter dated June 5, 2020 – PNG Submitting evidentiary update to Response to BCUC Information Request No. 2 question 90.1
B-7-3	Letter dated June 9, 2020 – PNG Submitting redacted confidential Responses to Panel Information Request No. 117
B-8	Letter dated May 20, 2020 – PNG Submitting Response to BCOAPO Information Request No. 2
B-9	Letter dated June 8, 2020 – PNG Submitting Response to Panel Information Request No. 1
B-10	**CONFIDENTIAL** - Letter dated June 8, 2020 – PNG Submitting confidential Response to Panel Information Request No. 1
B-10-1	**CONFIDENTIAL-Redacted** - Letter dated June 8, 2020 – PNG Submitting redacted confidential Responses to Panel Information Request No. 1
B-11	**CONFIDENTIAL** Letter dated June 18, 2020 – PNG Submitting request for confidential response to BCUC Panel IR No. 1 on RECAP Bid Process

B-12	Letter dated June 30, 2020 – PNG submitting responses to BCUC IR No. 1 on Evidentiary Update
B-13	Letter dated August 10, 2020 – PNG Submitting Response to Panel Information Request No. 2
B-14	**CONFIDENTIAL** - Letter dated August 10, 2020 – PNG Submitting confidential Response to Panel Information Request No. 2

INTERVENER DOCUMENTS

C1-1	**BC OLD AGE PENSIONERS' ORGANIZATION, ACTIVE SUPPORT AGAINST POVERTY, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, DISABILITY ALLIANCE BC, TENANTS RESOURCE AND ADVISORY CENTRE, AND TOGETHER AGAINST POVERTY SOCIETY, KNOWN COLLECTIVELY IN REGULATORY PROCESSES AS "BCOAPO ET AL." (BCOAPO ET AL)** - Letter dated January 31, 2020 - Request for Intervener Status by Leigha Worth and Irina Mis, British Columbia Public Interest Advocacy Centre
C1-2	Letter dated March 30, 2020 – BCOAPO Information Request No. 1 to PNG
C1-3	Letter dated May 1, 2020 – BCOAPO Information Request No. 2 to PNG

INTERESTED PARTY DOCUMENTS

D-1	**FORTISBC ENERGY INC. (FEI)** – Submission dated December 23, 2019 – Request for Interested Party Status by Doug Slater
D-2	**TATTERSALL, K.** - **S**ubmission dated January 22, 2020 – Request for Interested Party Status
D-2-1	Letter dated January 21, 2020 – Tattersall submitting Letter of Comment

LETTERS OF COMMENT

E-1	Cote, M. - Letter of Comment dated January 1, 2020
E-2	Gibson, J. - Letter of Comment dated January 9, 2020
E-3	Keehn, M. – Letter of Comment dated January 23, 2020