Pacific Northern Gas (N.E.) Ltd.
750 – 888 Dunsmuir Street
Vancouver, BC V6C 3K4
Tel: (604) 691-5680
Fax: (604) 697-6210
Email: votto@png.ca

Verlon G. Otto
Director, Regulatory Affairs

Via E-file

April 15, 2020

B.C. Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2.7(2020)

Attention: Patrick Wruck
Commission Secretary and Manager, Regulatory Services

Dear Mr. Wruck:

Re: Pacific Northern Gas Ltd.
PNG-West Division
2020-2021 Revenue Requirements Application
Response to BCUC Information Request No. 1

Accompanying, please find the response of Pacific Northern Gas Ltd. to the referenced information request.

Please direct any questions regarding the application to my attention.

Yours truly,

Verlon G. Otto

Enclosure

Pacific Northern Gas Ltd.
2020-2021 Revenue Requirements Amended Application

INFORMATION REQUEST NO. 1 TO PACIFIC NORTHERN GAS LTD.

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A. GENERAL

1.0 Reference GENERAL
Cybersecurity

1.1 Please confirm, or explain otherwise, that Pacific Northern Gas (PNG) has a cybersecurity emergency recovery plan. If confirmed, please provide a copy. If not, please explain why not and identify any risks associated with this.

Response:

PNG has been working on documenting its IT disaster recovery plan which includes a section that addresses the recovery from a cyber attack and expects to complete this by the end of 2020. PNG notes that it has undergone major IT infrastructure changes in 2019 and therefore delayed the documentation of its IT disaster recovery plan. PNG also notes that even without a formally documented cybersecurity emergency recovery plan, the PNG Emergency Response Plan has general guidelines and activities to address such incidents.

Although the PNG IT disaster recovery plan has not been formally finalized and documented, the Company is well positioned and ensures that the majority of its critical information systems, including finance, payroll and customer billing are operationally maintained as these systems are hosted and managed by third-party vendors and/or affiliates. These vendor/affiliates have proper cybersecurity response processes, which are addressed in Service Level Agreements (SLAs) with PNG while satisfying business requirements. The remaining PNG corporate systems and data are backed up daily in two separate locations including Vancouver and Terrace. Please also see the response to Question 1.2 which describes the steps taken by PNG to protect its data and systems.

1.2 Please explain the measures PNG has already taken to protect critical infrastructure and prevent cyber attacks.

Response:

PNG's critical infrastructure is currently architected in a manner that is inaccessible through the public internet and therefore not exposed to most cyber vulnerabilities. When required to access critical infrastructure, PNG technicians must remotely dial in through a modem and enter two passwords to gain access into the system. There is complete separation between the corporate network and the network on which PNG's critical infrastructure resides.

During 2019, PNG launched an ongoing cybersecurity awareness program to employees to ensure that they are all aware of potential phishing threats. The Company is also making changes to its firewall, continuously improving security plans for its assets and operations.

PNG completed the implementation of the McAfee cyber incident detection tool which is now fully operational. This tool provides early detection of cyber exploits, allowing PNG to respond more quickly thereby minimizing the impact on its corporate assets. PNG will continue to monitor and revise the configuration of this tool as the cyber security landscape changes.

PNG has also purchased Tenable, a vulnerability management tool which will be used to scan PNG's IT environment to identify and verify vulnerabilities and misconfigurations and prioritize their remediation. PNG plans to launch this program in April 2020 with the full implementation of all features.

PNG has and will continue to report to the BCUC regularly on its measures taken to protect critical infrastructure and prevent cyber attacks.

1.2.1 For any planned, future measures, please include a description and provide the implementation timeline for these measures.

Response:

PNG is planning to implement the capability for its technicians to remotely connect to the Company's critical infrastructure utilizing the internet in 2020. The plan is to contract out the design and implementation to consultants specializing in securing industrial control systems (ICS). PNG is cognizant of the potential impact on risk when enabling such capability and will ensure it is implemented using industry best practices.

Within the TriSummit Utilities Inc. (TSU, formerly ACI) consolidated group, an analysis is underway to identify opportunities for additional improvements across all the entities, with the intention of implementing a more mature cybersecurity framework across the entire organization. After the analysis is completed, additional measures will be undertaken as appropriate on a cost-effective basis for PNG.

B. DEMAND FORECAST, REVENUE AND MARGIN

2.0 Reference: DEMAND FORECAST, REVENUE AND MARGIN
Exhibit B-2 (Amended Application), Section 1.3, pp. 7, 25
Demand Forecast, Revenue and Margin

On page 7 of the Amended Application, PNG states:

> PNG-West also notes that with the positive FID decision on the LNG Canada project resulting in increased economic activity in PNG-West's service territory and PNG-West's proposed Reactivated Capacity Allocation Process (RECAP) in 2020, PNG-West is confident it will realize significant additional revenues from new customers to the benefit of existing ratepayers in the near future.

2.1 Please provide an update on the timing for commencement of the RECAP and an estimate of the incremental volumes and the expected year in which they will materialize.

Response:

Due to the many levels of business disruptions resulting from the COVID-19 crisis, PNG has delayed the commencement of the RECAP auction to the end of April 2020 or possibly later. This delay is intended to allow project developers the opportunity to secure business arrangements that support their participation in the auction. While the auction has not been executed yet, PNG continues to be optimistic on the opportunity to secure commercial commitments for transportation capacity.

The RECAP auction is currently being designed to enable prospective shippers to contract for up to 80 MMCFD of transportation capacity. Depending on the volume and delivery point requested, the in-service date for specific projects could be as soon as Q3 2021 or as late as Q4 2024. For example, a project with volumes of 20 MMCFD to be delivered to Terrace could be available in the Q3 2021 timeframe due to minimal capital work required, whereas a project with volumes of 80 MMCFD to be delivered to Terrace would require substantially more reactivation work and is estimated to be in-service in the Q4 2024 timeframe.

Further on page 25 of the Amended Application, PNG states:

> There is an overall increase in forecast deliveries of approximately 180,000 GJ for Large Commercial Firm sales. Of this increase, 176,000 GJ can be attributed to forecast demand for two new customers, one in Kitimat involved in the construction of a liquefied natural gas (LNG) export facility in that city, and one in Prince Rupert developing a propane export terminal.

2.2 Please provide a breakdown of the incremental 2020 and 2021 volumes for each of the new customers identified in the preamble.

Response:

Please see table that follows.

	Incremental 2020 GJ	Incremental 2021 GJ
Kitimat Customer	168,417	181,489
Prince Rupert Customer	7,820	23,205
	176,237	204,694

3.0 Reference: DEMAND FORECAST, REVENUE AND MARGIN
Exhibit B-2, Section 2.1, p. 23
Demand Forecast, Revenue and Margin

On page 23 of the Amended Application, PNG states:

> The forecast gas delivery volumes and margin for Test Year 2020 and Test Year 2021 are summarized and compared to the Decision 2019 forecast amounts in the table below. Reductions in Test Year 2020 and Test Year 2021 amounts from Decision 2019 are indicated by figures in brackets. A discussion of significant variances follows.

Further on page 23 of the Amended Application, PNG provides Table 9 with forecast gas deliveries.

3.1 Please provide a table in the same format as Table 9 that compares the actual 2019 deliveries with the forecast 2020 deliveries for each customer class. Please also provide an explanation for any significant variances between the actual 2019 deliveries and the forecast 2020 and 2021 deliveries and between the actual and decision 2019 deliveries for each customer class.

Response:

Please see table and explanation of variances that follow.

Customer Classification	Test Year 2021 Deliveries	2021 to 2020 Change in Forecast Deliveries	Test Year 2020 Deliveries	2020 to 2019 Change from Decision Deliveries	2020 to 2019 Change from Actuals Deliveries	Decision 2019 Deliveries	2019 Change Actual vs. Decision Deliveries	Actual 2019 Deliveries	Actual 2018 Deliveries	Actual 2017 Deliveries	Actual 2016 Deliveries
	GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ	GJ
Residential	1,223,130	2,025	1,221,105	(29,555)	49,679	1,250,660	(79,234)	1,171,426	1,144,971	1,291,278	988,076
Granisle	5,796	(155)	5,951	401	529	5,550	(128)	5,422	5,709	5,049	5,530
Commercial											
Small Commercial Firm (Rate 2)	720,322	(18,807)	739,129	(44,955)	(1,744)	784,084	(43,211)	740,873	725,807	806,929	654,474
Small Comm Transport (Rate 22)	156,267	(4,500)	160,767	4,600	6,605	156,167	(2,005)	154,162	156,241	177,345	144,870
Large Commercial Firm (Rate 3)	426,231	204,964	221,267	179,767	174,862	41,500	4,905	46,405	45,331	17,710	37,409
Large Comm Transport (Rate 33)	149,200	4,500	144,700	5,400	(4,332)	139,300	9,732	149,032	145,534	157,505	131,968
Commercial Interruptible (Rate 5)	42,000	-	42,000	(500)	754	42,500	(1,254)	41,246	40,348	44,905	42,359
Total Commercial	1,494,020	186,157	1,307,863	144,312	176,145	1,163,551	(31,833)	1,131,718	1,113,261	1,204,394	1,011,080
Seasonal Off-peak	18,400	-	18,400	(15,900)	3,398	34,300	(19,298)	15,002	21,421	43,488	40,297
NGV	-	-	-	(12)	-	12	(12)	-	-	675	2,770
Small Industrial											
Sales (Rate 4)	423,410	(4,034)	427,444	(47,896)	33,340	475,340	(81,236)	394,104	126,647	182,862	153,784
Transport	-	-	-	-	-	-	-	-	-	-	893
Interruptible Transport	674,050	(1,500)	675,550	23,050	(62,653)	652,500	85,703	738,203	709,132	799,520	732,265
	1,097,460	(5,534)	1,102,994	(24,846)	(29,313)	1,127,840	4,467	1,132,307	835,779	982,382	886,942
Large Industrial Transport											
Rio Tinto Alcan	1,523,947	(4,175)	1,528,122	161,716	262,625	1,366,406	(100,909)	1,265,497	1,287,765	1,366,678	1,301,913
BC Hydro	24,000	-	24,000	-	(325,273)	24,000	325,273	349,273	149,078	14,567	90,512
	1,547,947	(4,175)	1,552,122	161,716	(62,648)	1,390,406	224,364	1,614,770	1,436,843	1,381,245	1,392,425
Total	**5,386,753**	**178,318**	**5,208,435**	**236,116**	**137,790**	**4,972,319**	**98,326**	**5,070,645**	**4,557,984**	**4,908,511**	**4,327,120**

Actual 2019 vs. Decision 2019

- Deliveries for the Residential and Small Commercial class are lower than Decision 2019 by 122,000 GJ mainly due to lower use per account as a result of warmer than normal weather.

- Large Commercial Transport deliveries increase of 10,000 GJ is a result of variances from forecasts provided by customers.

- Deliveries to Seasonal class consisting of paving plants are lower by approximately 19,000 GJ due to less than anticipated paving activities.

- The decrease of 81,000 GJ in Industrial Sales is due to the reclassification of a wood pellet plant situated in Smithers to Interruptible Transport class, partially offset by increases from the addition of a new pellet plant in Terrace and increased deliveries to Ridley Island Propane Export Terminal.

- Increase of 86,000 GJ in Interruptible Transport class is due to noted re-class of the wood pellet plant from Small Industrial Sales partially offset by closure of a sawmill in Fort. St. James and lower deliveries to a pellet plant in Houston.

- Large Industrial Transport deliveries increase of 224,000 GJ is mostly attributed to BC Hydro running their generating station to meet their energy system needs and satisfy load requirements. This is partially offset by lower than the minimum contractual take-or-pay deliveries to Rio Tinto Alcan. PNG notes that variances from forecast deliveries for both these customers are recorded in the Industrial Customers Deliveries Deferral Account (ICDDA).

Actual 2019 vs. Test Year 2020

- Residential deliveries for 2020 are greater by 50,000 GJ due to forecast increased customer count and higher use per account.

- Increase of 175,000 GJ in Large Commercial class mainly due to forecast addition of new customers, either involved in construction activities related to LNG export terminal in Kitimat or propane export facility in Prince Rupert. Some of this increase is partially offset by reclassification of customers to the Small Commercial Sales class.

- The 33,000 GJ increase in Industrial Sales class is based of forecasts provided by customers and a review of their recent historical usage.

- Decrease of 63,000 GJ in Interruptible Transport class reflects the closure of a Fort St. James sawmill offset in part by forecast increased demand as per customer survey responses and a review of recent historical usage.

- Decrease of 63,000 GJ in Large Industrial Transport is due to assumption that BC Hydro will be running their Prince Rupert generating station on a stand-by basis. This is partially offset by increase to Rio Tinto Alcan forecast to reflect their minimum contractual take-or-pay volume. PNG notes that the ICDDA applies to both of these customers.

Actual 2019 vs. Test Year 2021

In addition to the variances explained in the above segment comparing Actual 2019 to Test Year 2020, additional variances in Test Year 2021 compared to Actual 2019 include:

- An incremental decrease of 19,000 GJ in Small Commercial class due to forecasted lower use per account; and

Additional increase of 205,000 GJ in Large Commercial class mainly attributed to increased demand from the noted new customers related to the Kitimat LNG export facility, including a second sales agreement, and the Prince Rupert propane export terminal.

4.0 Reference: DEMAND FORECAST, REVENUE AND MARGIN
Exhibit B-2, Section 2.1.1, pp. 23-24; Section 2.1.2, p. 24
Pacific Northern Gas Ltd. and Pacific Northern Gas (N.E.) Ltd. Application for Acceptance of 2019 Consolidated Resource Plan and for Acceptance of Energy Conservation and Innovation (ECI) Portfolio Funding for 2020 to 2022 proceeding (PNG 2019 Consolidated Resource Plan), Exhibit B-1, Section 7.3.1.2, p. 88, Figure 26 Residential and Small Commercial Deliveries and Margin

On pages 23 and 24 of the Amended Application, PNG states:

> The forecast Test Year 2020 and Test Year 2021 deliveries to the Residential class are based on the forecast normalized Use per Account (UPA) multiplied by the forecast number of customers.

The methodology to forecast deliveries of small commercial customers is the same as residential customers as explained in Section 2.1.2 on page 24 of the Amended Application.

Further on pages 23 and 24, PNG provides Tables 10 and 11 for forecast customer count and use per account for residential and small commercial customers.

4.1 Please reconcile the forecast deliveries for 2020 and 2021 in Table 9 of the Amended Application for the residential and small commercial customers with the data contained in Table 10 and 11, respectively.

Response:

The forecast deliveries to the Residential and Small Commercial classes are based on the forecast normalized Use Per Account multiplied by the forecast customer count. The derivation of the forecast figures presented in Table 9 are the summation of this monthly calculation. The customer counts at year end and use per accounts figures referenced in Tables 10 and 11 are for illustrative reporting, however they correspond to the figures shown in tables that follow.

2021 Residential Forecast:

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Customer Count	17,905	17,913	17,918	17,888	17,830	17,807	17,778	17,768	17,823	17,898	17,958	17,981	
Use Per Account	10.3	7.8	7.8	5.2	3.6	1.9	1.7	1.6	2.9	5.7	8.7	11.2	68.3
Deliveries (GJ)	184,467	139,151	139,784	92,270	64,191	33,769	29,668	28,236	52,334	101,873	156,294	201,093	1,223,130

2020 Residential Forecast:

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Customer Count	17,823	17,831	17,836	17,806	17,746	17,723	17,693	17,683	17,742	17,817	17,877	17,900	
Use Per Account	10.3	7.8	7.8	5.2	3.6	1.9	1.7	1.6	2.9	5.7	8.7	11.2	68.5
Deliveries (GJ)	184,160	138,920	139,552	92,116	64,076	33,708	29,613	28,183	52,249	101,709	156,045	200,774	1,221,105

2021 Small Commercial Forecast:

	Jan-21	Feb-21	Mar-21	Apr-21	May-21	Jun-21	Jul-21	Aug-21	Sep-21	Oct-21	Nov-21	Dec-21	Total
Customer Count	2,473	2,475	2,473	2,474	2,468	2,471	2,469	2,467	2,470	2,473	2,472	2,474	
Use Per Account	42.2	40.9	32.6	21.9	10.9	8.4	6.5	7.8	11.8	22.9	36.4	48.8	291.3
Deliveries (GJ)	104,481	101,299	80,636	54,186	26,938	20,862	16,115	19,161	29,155	56,697	90,058	120,734	720,322

2020 Small Commercial Forecast:

	Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20	Jul-20	Aug-20	Sep-20	Oct-20	Nov-20	Dec-20	Total
Customer Count	2,467	2,470	2,467	2,468	2,462	2,466	2,465	2,463	2,466	2,469	2,468	2,470	
Use Per Account	43.4	42.1	33.5	22.5	11.2	8.7	6.7	8.0	12.1	23.6	37.5	50.2	299.5
Deliveries (GJ)	107,162	103,941	82,704	55,576	27,629	21,406	16,541	19,669	29,927	58,198	92,444	123,932	739,129

On page 88 of the Application in PNG's 2019 Consolidated Resource Plan proceeding, PNG states the following and provides Figure 26 illustrating the trend in residential use per account for PNG-West (figure not reproduced):

> The performance of PNG's forecasting method over the five years since the last resource plans were submitted is also presented. Actual UPA in all systems over the period from 2014 to 2018 has been lower than forecast in the previous resource plans. The impact of the Clean BC policy actions is reflected in a sharper decrease in UPA over the forecast period, as compared to the previous forecasts.

4.2 Please explain whether the 2020 and 2021 forecast residential UPA included in the Revenue Requirements Application (RRA) have been updated to include the impact of Clean BC noted in PNG's 2019 Consolidated Resource Plan. If yes, please discuss how these factors have been incorporated. If not, please explain why not.

Response:

The anticipated impact of CleanBC policies has not been reflected in the 2020 and 2021 forecast residential UPA included in the RRA. The forecast residential UPA incorporated into the Amended Application have been determined consistent with the method applied in prior revenue requirements applications. The forecast residential UPA represents the mid-point between the test year forecast normalized UPA and the linear trend of customer use.

The impact of CleanBC policies is expected to influence the residential UPA over a period of time beyond the 2020 to 2021 period of this Amended Application. The long term forecast of residential UPA presented in PNG's 2019 Consolidated Resource Plan is based on a residential end-use model that is designed to reflect the impact of CleanBC policies such as increased electrification of space heating and increased energy efficiency of new and existing residential dwellings.

PNG submits that standards and regulations supporting the CleanBC policies need to be in place for a sufficient period of time to make a measurable impact on the residential UPA in future periods' revenue requirement applications. PNG also submits that its existing short-range forecasting methodology will remain valid in extrapolating the residential UPA for the purpose of a one or two year revenue requirements application based on a most recent trend in UPA and one that reflects the impact of the CleanBC policies.

4.3 Please explain the pros and cons of using the residential and small commercial forecasting methodology used in PNG's 2019 Consolidated Resource Plan versus the one used in the 2020-2021 RRA.

Response:

The long-range forecasting methods used to forecast residential and small commercial demand for the 2019 Consolidated Resource Plan are designed to capture changes in customer behaviour resulting from policies, changes in appliance and building efficiency standards, and regulations that are anticipated to come into effect over the 20-year planning period spanned by the resource plan and which may not be in effect today.

The short-range forecasting model used to forecast demand over the next one to two years for the purposes of this Amended Application is based on an extrapolation of existing trends in UPA. These trends reflect current customer behaviour in response to current policies and economic considerations. The short-range model therefore cannot anticipate the impact of changes to policies, regulations and standards that may influence customer demand.

A comparison of the "pros and cons" of each model suggests to PNG that the BCUC wishes PNG to consider adopting one model or the other for developing forecasts for all purposes. PNG respectfully submits that harmonizing the forecasting methodology in such a manner is not appropriate, nor is it necessary. Both the long-range and the short-range forecasting models are appropriately used for their intended purpose, i.e. in the development of forecasts for resource planning and for revenue requirements applications respectively. Conversely, either model would be ill-suited to serve a purpose for which it was not designed. For example, the short-range model would not provide a realistic view of customer demand over the 20 years spanned by a resource plan.

PNG also notes that in the 2016-2017 Revenue Requirements Application, PNG had proposed a new method for residential and small commercial load forecasts in a first step to harmonize it methods for forecasting design day demand in a consistent manner across all of its regulatory filings. Under Order G-131-16, the BCUC did not accept PNG's proposal and directed PNG to recalculate its load forecasts using its existing load forecasting method for the 2016-2017 Revenue Requirements Application.

4.3.1 Please provide an analysis of the performance of both the forecasting methods by comparing the actual versus forecasted UPA and customer additions for the residential and small commercial customers for the 2015-2019 period.

Response:

Please see the tables that follow. The long-range forecast is that provided in the 2014 Resource Plan for PNG-West. The short-range forecasts are those provided in the 2015, 2016-2017, and 2018-2019 revenue requirements applications.

Both the short-range model used to forecast UPA and customer counts for the purpose of the revenue requirements application, and the long-range model used for resource planning exhibit similar accuracies over the period from 2015 to 2019, with the long-range model achieving slightly better results for the residential UPA, while the short-range model performs slightly better in forecasting customer counts.

Residential Use per Account (GJ)	2015	2016	2017	2018	2019	Average (2015 - 2019)	Std Dev (2015 - 2019)
Actual	67.8	67.6	72.0	66.8	68.3		
Short-Range Model (RRA)	72.1	69.1	70.0	70.8	70.8		
Variance in Short-Range Model	6.3%	2.2%	-2.8%	6.0%	3.7%	3.1%	3.7%
Long-Range Model (Resource Plan)	70.2	70.0	69.8	69.5	69.4		
Variance in Long-Range Model	3.6%	3.6%	-3.1%	4.1%	1.7%	2.0%	3.0%

Small Commercial Use per Account (GJ)	2015	2016	2017	2018	2019	Average (2015 - 2019)	Std Dev (2015 - 2019)
Actual	291.6	330.2	324.2	294.0	298.3		
Short-Range Model (RRA)	315.1	290.5	292.9	312.4	318.8		
Variance in Short-Range Model	8.1%	-12.0%	-9.7%	6.3%	6.9%	-0.1%	9.9%
Long-Range Model (Resource Plan)	307.6	306.4	305.2	304.3	303.4		
Variance in Long-Range Model	5.5%	-7.2%	-5.8%	3.5%	1.7%	-0.5%	5.7%

Residential Customers	2015	2016	2017	2018	2019	Average (2015 - 2019)	Std Dev (2015 - 2019)
Actual	17,721	17,738	17,680	17,712	17,815		
Short-Range Model (RRA)	17,714	17,750	17,779	17,691	17,706		
Variance in Short-Range Model	0.0%	0.1%	0.6%	-0.1%	-0.6%	0.0%	0.4%
Long-Range Model (Resource Plan)	17,681	17,837	18,024	18,208	18,382		
Variance in Long-Range Model	-0.2%	0.6%	1.9%	2.8%	3.2%	1.7%	1.5%

Small Commercial Customers	2015	2016	2017	2018	2019	Average (2015 - 2019)	Std Dev (2015 - 2019)
Actual	2,471	2,449	2,452	2,465	2,464		
Short-Range Model (RRA)	2,483	2,469	2,467	2,456	2,461		
Variance in Short-Range Model	0.5%	0.8%	0.6%	-0.4%	-0.1%	0.3%	0.5%
Long-Range Model (Resource Plan)	2,453	2,471	2,487	2,502	2,515		
Variance in Long-Range Model	-0.7%	0.9%	1.4%	1.5%	2.1%	1.0%	1.1%

On page 24 of the Amended Application, PNG states:

> The Test Year 2020 and Test Year 2021 forecast normalized UPAs are 68.5 GJ and 68.3 GJ, respectively, and represent the mid-point between the test year forecast normalized UPA and the linear trend of customer use. The forecast number of customers is based on the recent trend experienced for the service area.

4.4 Please explain why the actual UPA for 2017 provided in Table 10 (72 GJ) of the RRA is different from the actual UPA for 2017 provided in Figure 26 of PNG's 2019 Consolidated Resource Plan (66.7 GJ).

Response:

The correct figure is 72.0 GJ as provided in Table 10 of the Amended Application. The 66.7 GJ reported for 2017 in the 2019 Consolidated Resource Plan is an error resulting from an incorrect link that occurred when rolling forward models. PNG regrets any confusion this may have caused and submits that this error does not have any impact on the forecast figures presented in the Amended Application, or in the forecasts presented in the 2019 Consolidated Resource Plan.

4.5 Please explain how the UPA provided in PNG's 2019 Consolidated Resource Plan impacts the linear trend of customer use, forecast residential UPA and deliveries for 2020 and 2021.

Response:

Please see the response to Question 4.2. PNG utilizes a short-term forecasting model when forecasting customer use, residential UPA and deliveries for 2020 and 2021 that is based on an extrapolation of historical data. The forecast residential UPA and deliveries presented in PNG's 2019 Consolidated Resource Plan is based on an end-use model that reflects anticipated trends in customer behaviour over longer time periods.

5.0 Reference: DEMAND FORECAST, REVENUE AND MARGIN
Exhibit B-2, Section 2.1.3.3, p. 23
Industrial Deliveries and Margin

On page 27 of the Amended Application, PNG explains the forecast for its Large Industrial Transport customer class and states:

> BC Hydro [British Columbia Hydro and Power Authority] forecast deliveries for Test Year 2020 and Test Year 2021 are based on the assumption that BC Hydro will continue to operate its Prince Rupert generating station as a backup facility. The 24,000 GJ figure is consistent with historical deliveries during those years when BC Hydro has operated its generating station on a standby basis and placed it into service during times of emergency.

5.1 As presented in Table 9 of the Amended Application, BC Hydro actual deliveries have ranged from 14,567 GJ to 349,273 GJ for the period 2016 to 2019, indicating BC Hydro operated this generation facility more frequently in some years. Please explain which years are consistent with the period that BC Hydro operated its generation station as a backup facility and which years are not.

Response:

The table that follows illustrates BC Hydro deliveries for the years that BC Hydro operated its generation station as a backup facility.

	2012	2013	2014	2017
BC Hydro Deliveries (GJ)	14,548	25,556	31,063	14,567

5.1.1 Based on the years that BC Hydro operated its generation facilities as a back-up facility please explain how the 24,000 GJ demand was calculated.

Response:

PNG reviewed the deliveries for BC Hydro over the 2012 to 2019 years and remained with the forecast of 24,000 GJs calculated from taking their average annual usage for the period for the 2012 to 2014 as has been done in recent prior forecasts. In discussions with BC Hydro, it was confirmed this was still a reasonable proxy to use for the Test Year 2020 and Test Year 2021.

	2012	2013	2014	Average
BC Hydro Deliveries (GJ)	14,548	25,556	31,063	23,722

5.2 Please discuss the probability that BC Hydro annual demand profile for Prince Rupert generating station will be greater than 24,000 GJ in 2020 and 2021.

Response:

As indicated in the preamble, BC Hydro typically operates the Prince Rupert generating station as backup in years of low water resources or in the case of a disruption of the power transmission system supplying the local region. Both of these events are random and typically have a low probability. PNG also notes that variances from forecast deliveries are recorded in the Industrial Customers Deliveries Deferral Account (ICDDA) to be amortized the following year.

5.3 Please discuss whether BC Hydro has confirmed to PNG that it will continue to operate the Prince Rupert generating facility on a standby basis in 2020 and 2021 and that 24,000 GJ is their maximum demand when its generating station is operated on a standby basis.

Response:

In discussions regarding the RECAP process, BC Hydro has recently confirmed that it is not prepared to contract for firm transportation service, instead opting to continue with the existing interruptible service. This decision by BC Hydro is consistent with an anticipated short-term, interruptible operation on a standby basis. Please also see the response to Question 5.1.1.

C. COST OF GAS

6.0 Reference: COST OF GAS
Exhibit B-2, Section 2.2.3, pp. 29-33; Appendix B, p. 4; PNG-West's 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 55.16, Exhibit B-1-1, Appendix B, p. 8
Unaccounted for Gas

On page 30 of the Amended Application, PNG states:

> Historically, there have been offsetting gains and losses such that a zero percent UAF loss remained a satisfactory proxy for setting the Company use recovery rate, consequently PNG-West did not see a need to make a change to this provision.
>
> However, PNG-West submits that its recent experience supports a change to this provision. For the five-year period of 2015 to 2019, PNG-West has experienced average net UAF losses equal to 1.88% of deliveries. In light of the forgoing, PNG-West submits that establishing the UAF component of Company use gas at 1.0 percent of deliveries and reflecting this in the cost of service is appropriate. PNG-West notes that this proposal is predicated on continued use of the UAF Volume deferral account.

On page 32, PNG provides Table 15 with the contribution of the four primary drivers to UAF volumes on the PNG-West system.

6.1 Please discuss any specific reasons why there have not been offsetting gains and losses in UAF gas in 2015 to 2019 as compared to the 2004 to 2014 time period.

Response:

While abnormally large UAF gains or losses in each month are examined for their cause, often times such deviations are reversed over the next two months, owing to an under- or over-statement of either the residential or small commercial unbilled estimate. Any persistent gain beyond the three months is generally considered to be due to some other underlying cause and such a trend triggers a more in depth examination of all metered data, data conversion factors and physical changes at custody transfer receipt points. Such an examination is taking place now.

At this time, PNG has not determined the cause or causes for the accumulated UAF volume exceeding 1.0 percent of deliveries during 2019. PNG continues its internal examination of all data and calculations influencing the determination of the monthly UAF volumes. In addition, PNG will be conducting an extensive review of the data and calculations associated with the determination of the monthly UAF. 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.

PNG proposes to submit findings from its examination in an update to the BCUC in the third quarter of 2020.

6.2 Please explain how the UAF loss percentages on PNG-West's system compares with other gas utilities with similar systems to PNG.

Response:

Please see the table that follows for a comparison of available UAF loss percentages of selected 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%

6.3 Please provide the actual UAF losses, total deliveries, the UAF losses as a percentage of deliveries and the value of UAF losses for each year between 2004 and 2019.

Response:

Please see the table that follows.

		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)

6.4 For each year of the five-year period from 2015-2019, please explain the reasons for the UAF losses. In your response, please also explain how each of the primary drivers of the UAF volumes affect UAF losses for that year.

Response:

PNG has not determined a specific cause of the UAF losses in each year of the 2015-2019 period. Primary factors influencing the UAF on the PNG-West system described on pages 30 to 32 of the Amended Application are: (i) errors in the volumes recorded by custody transfer flow meters receiving gas from the Enbridge T-South system at Summit Lake and errors in customer meters, primarily those of PNG's large industrial customers; (ii) inaccuracies in the estimate of the change in monthly linepack on the PNG-West transmission system; (iii) inaccuracies in the estimate of blown down and vented gas; and (iv) errors in the estimate of the monthly and bi-monthly billed customers.

On page 29 of the Amended Application, PNG states: "Primary reasons for natural gas loss which goes unaccounted include: meter inaccuracy; leakages from pipelines due to third-party damage or problems with pipelines themselves; theft issues and meter tampering; and variations in surrounding temperature."

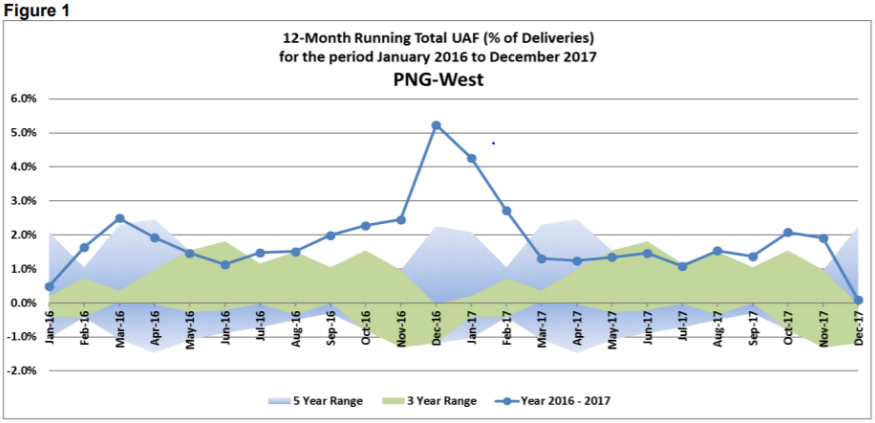
6.5 Please discuss how each of the primary reasons for gas loss discussed on page 29 of the Amended Application contribute to UAF gas for PNG, with specific reference to how they relate to the primary drivers for UAF gas volumes on the PNG system in Table 15.

Response:

PNG believes that the discussion presented on pages 30 to 32 of the Amended Application addresses this question. PNG accounts for all known sources of gas loss on the PNG-West system before determining the UAF. The UAF is therefore determined from inaccuracies in the metered natural gas receipts, and metered and estimated natural gas deliveries, as well as errors in the estimated quantities of gas lost through venting and blowdowns, and estimated changes in linepack.

On page 4 of Appendix B to PNG-West's Amended 2018-2019 RRA, PNG provided the following Figure 1:

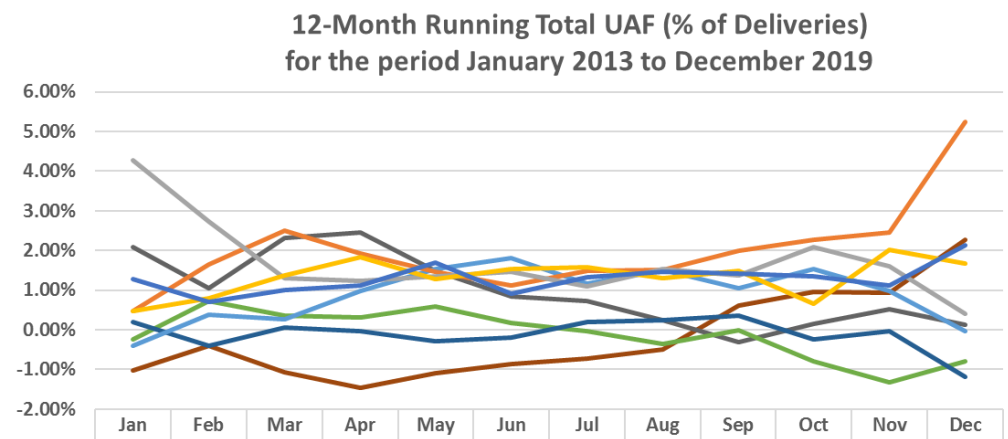
Figure 1



6.6 Please provide a graph consistent with the figure above for the actual 12-Month Running Total UAF (% of deliveries) for the 2015-2019 period.

Response:

Please see the chart that follows. PNG has extended the period covered by the chart to January 2011, rather than 2015 as requested, in order to maintain consistency with the ranges presented in Figure 1, above. In that figure, the green and blue shaded areas represent the range of 12-month running total UAF during the periods 2013 – 2015 and 2011 – 2015, respectively.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2011	-1.03%	-0.40%	-1.08%	-1.46%	-1.09%	-0.87%	-0.72%	-0.49%	0.61%	0.95%	0.93%	2.26%
2012	2.08%	1.05%	2.31%	2.46%	1.50%	0.85%	0.72%	0.25%	-0.31%	0.15%	0.51%	0.12%
2013	-0.24%	0.72%	0.36%	0.30%	0.58%	0.17%	-0.03%	-0.36%	0.00%	-0.80%	-1.32%	-0.80%
2014	0.20%	-0.41%	0.06%	-0.04%	-0.28%	-0.20%	0.20%	0.24%	0.35%	-0.24%	-0.02%	-1.18%
2015	-0.4%	0.4%	0.3%	1.0%	1.5%	1.8%	1.2%	1.5%	1.0%	1.5%	1.0%	0.0%
2016	0.5%	1.6%	2.5%	1.9%	1.5%	1.1%	1.5%	1.5%	2.0%	2.3%	2.4%	5.2%
2017	4.3%	2.7%	1.3%	1.2%	1.3%	1.5%	1.1%	1.5%	1.4%	2.1%	1.6%	0.4%
2018	0.5%	0.8%	1.4%	1.8%	1.3%	1.5%	1.6%	1.3%	1.5%	0.6%	2.0%	1.7%
2019	1.3%	0.7%	1.0%	1.1%	1.7%	0.9%	1.3%	1.5%	1.4%	1.3%	1.1%	2.1%

On page 33 of the Amended Application PNG submits:

> Based on PNG-West's view that it is inappropriate for shareholders to bear all of the risk of UAF losses above a pre-determined level when customers benefit when UAF losses are less than this level, PNG-West is recommending that the UAF Loss Cap be set at 1.5 percent with PNG-West being obliged to apply for BCUC approval to record UAF losses above 1.5 percent in the UAF volume deferral account.

6.7 Please provide the UAF losses borne by PNG's shareholders and the benefits related to UAF for PNG's ratepayers for each year between 2015 and 2019.

Response:

Please see the table provided in response to Question 6.3. The value of the UAF losses over the period from 2015 to 2019 total $743,000. In 2015 and 2017, UAF losses were below the threshold 1.0 percent below which PNG records the UAF loss amount in the UAF volume deferral without having to seek further BCUC approval. In 2016, 2018 and 2019, UAF losses exceeded the threshold 1.0 percent and PNG requested BCUC approval to record the full amount of the actual UAF losses in the UAF volume deferral account. The full amount of the UAF losses in 2016, 2018 and 2019 were $437,000, $116,000 and $148,000, respectively. The BCUC approved PNG's request in 2016, 2018 and again in 2019 by way of Orders G-151-18, G-86-19 and G-66-20, respectively.

The UAF volume deferral is amortized through the company use gas cost and recovered from all of PNG's sales and transportation customers.

In response to BCUC information request (IR) 55.16 in the PNG-West's 2018-2019 RRA proceeding, PNG stated:

> As stated on page 90 of the Amended Application, PNG intends to undertake a pilot installation of approximately 1,650 advanced metering units in order to evaluate the benefits of Automated Meter Reading (AMR) infrastructure. Data from these meters is expected to provide more information on the correlation between daily customer demand and ambient temperatures.
>
> In addition, PNG would need to initiate a customer end-use survey in order to understand better the efficiencies of the gas appliances and building characteristics associated with the AMR installations. PNG last completed a Residential End Use Survey (REUS) in 2015.
>
> Finally, PNG would need to engage a consultant to undertake a statistical analysis in order to refine its customer end-use model and unbilled consumption estimation method, all of which would then be based on a small sample of customers located in one geographic location.
>
> To summarize, PNG has identified opportunities for improving the quality of its customer information and revising its unbilled estimate. However, as stated in PNG's response to BCOAPO IR 1.4.1, PNG has evidence to suggest that the theoretical and practical floor for UAF on the PNG-West system is 0.68 and 1.0 percent, respectively.

6.8 Please explain whether PNG has implemented any of the measures discussed above to improve the accuracy of its customer information or estimate of unbilled estimates. If yes, please discuss the results. If not, please explain why not.

Response:

Aside from implementing a pilot installation of AMR meters in Thornhill, PNG has not implemented any of the measures discussed in the preamble. PNG has not prioritized its limited resources to complete the other initiatives. As stated in the portion of the response to the BCUC information request 55.16 in the PNG-West 2018-2019 Revenue Requirements Application proceeding that was not included in the preamble above, improvements to the unbilled estimate come at additional effort and cost, and the pursuit of these improvements is not expected to result in a significant improvement to the unbilled estimate.

6.9 Please identify measures that other utilities or industry players undertake to mitigate UAF losses and discuss whether these measures are applicable to the PNG system.

Response:

PNG is aware of programs from AltaGas Utilities Inc. (AUI) and ATCO Gas. AUI has implemented automated meter reading (AMR), system betterment activities, leak survey programs, regular meter testing and process improvements. ATCO Gas has implemented a program to monitor all regulating stations for low-flow conditions, since gas may not be measured accurately at receipt meters if the flow is below the minimum range of the meter. ATCO Gas is upgrading measurement equipment, data monitoring, verification of measurement data, seasonal operational adjustments, adjusting sample points and heat areas as necessary.

All of these measures are applicable to PNG. PNG has implemented a pilot AMR program to evaluate the effectiveness of the technology in its service area. PNG has also carried out system betterment activities, leak survey programs, regular meter testing and process improvements. As part of PNG's analysis of the source or sources of UAF on its system, PNG conducts an examination of its custody transfer meters at its receipt points, and of meters at its large industrial customers, as well as completes a review of the conversion of measurement data to corrected energy units.

6.10 Please explain why the theorical and practical floor for UAF on PNG-West's system has changed from "0.68 and 1.0 percent" discussed in the preamble above to the ± 1.13 and ± 1.5 provided in the Amended Application.

Response:

Please see the table that follows for a comparison of the determinants of the theoretical and practical floor for UAF on the PNG-West system. The magnitudes of each of the components are determined from an analysis of the most recent five years of historical data. With the exception of the estimated error in the unbilled estimate, all of the error components used to determine the 2019 threshold are reduced, as compared to 2009. The error in the unbilled estimate is increased based on the average of the net accruals over each of the previous five calendar years.

PNG wishes to point out that deliveries on the PNG-West system 2019, are approximately 30 percent lower as compared to 2009. On an absolute basis, the practical UAF floor of 1.5 percent, applied to the 2019 deliveries, results in a similar quantity of UAF – about 60,000 GJ – as the previous UAF floor of 1.0 percent applied to the 2009 deliveries.

	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

7.0 Reference: COST OF GAS
Exhibit B-2, Section 2.2.3, pp. 29-33
Unaccounted for Gas – Unbilled Estimate

On page 32 of the Amended Application, PNG states:

> Finally, errors in the unbilled estimate of monthly and bi-monthly billed customers whose meters are read on one of eight cycles rather than at the end of the calendar month are a significant contributor to UAF. The average of the net accruals over the 12-month period in each of the past five calendar years was compared to variations in heating degree days. Only two-thirds of the variability of the accruals could be explained by heating degree day variances; the remainder is due to the inability of the unbilled estimation algorithm, in all circumstances, to accurately reflect the physical consumption that occurred during the unbilled stub period. Based on PNG-West's analysis, deviations in the unbilled accrual from the actual, physical deliveries account for ± 42,200 GJ, or ± 0.88 percent UAF.

7.1 Please explain in detail how PNG calculates the unbilled estimate of monthly and bi-monthly billed customers.

Response:

PNG uses an Excel-based spreadsheet to balance physical gas receipts with deliveries to its core market and transportation customers on a calendar month basis. The volumes delivered are determined from a combination of metered deliveries and an estimate of the unbilled consumption by customers (the "unbilled estimate"). In the case of residential and small commercial customers, the unbilled estimate reflects the heat sensitive character of these customers' loads.

The residential and small commercial unbilled estimate is based on a third-order linear relationship between a representative customer's daily average consumption and the ambient temperature characterized by the daily heating degree day value averaged over a calendar month:

$$\text{Daily Average Consumption (GJ)} = Baseload + Heatload_1 \times HDD(18)_{Avg} + Heatload_2 \times HDD(18)^2 + Heatload_3 \times HDD(18)^3$$

Where:

Baseload	*= the per-customer, average daily gas consumption in GJ.*
$Heatload_{1,2,3}$	*= the first, second and third order factors determining the heat sensitive portion of a customer's daily gas consumption in GJ.*
$HDD(18)_{avg}$	*= Average daily heating degree day for the calendar month (i.e. The total heating degree days for the calendar month divided by the number of days in the month.)*

To arrive at the unbilled consumption for the calendar month, the resulting Daily Average Consumption is then multiplied by the number of days between when a customer's meter is read, and the end of the calendar month, aggregated over all customers.

7.2 Please explain what factors could lead to actual loss of gas from when the meters are read to when the unbilled estimate is calculated.

Response:

PNG interprets this question to mean what factors could lead to an actual loss of gas during the period between when the meters are read, and the end of the calendar month. Losses of gas due to blown downs of the PNG-West transmission system, venting of gas-actuated devices in compressor and regulating stations, and fugitive emissions from fittings and valves occur as part of PNG's routine operation. PNG estimates the quantity of gas lost through these processes and accounts for them when determining the UAF volumes. Only the difference between PNG's estimate of these emitted volumes, and the actual volumes is reflected in the UAF volume. As shown in Table 15 of the Amended Application, inaccuracies in the estimated blow down and vented volumes comprise a very small portion of the UAF.

7.3 Please explain the statement identified in the preamble that "the remainder is due to the inability of the unbilled estimation algorithm."

Response:

PNG notes that the entire statement in the preamble should read "Only two-thirds of the variability of the accruals could be explained by heating degree day variances; the remainder is due to the inability of the unbilled estimation algorithm, in all circumstances, to accurately reflect the physical consumption that occurred during the unbilled stub period."

The unbilled estimate is based a statistically derived equation provided in the response to Question 7.1 that describes the relationship between residential and small commercial daily average demand and ambient temperature. The unbilled estimate may not accurately reflect consumption during December owing to temperatures that can be at the extreme range of those used to develop the heat load factors, and to customer's consumption patterns that may be different during the holiday period, as compared to the rest of the year.

7.4 Please discuss how PNG utilizes heating degree days to forecast the volume of gas delivered.

Response:

Please see the response to Question 7.1.

7.5 How many customers have the meters read in one of the eight cycles rather than at the end of the calendar month?

Response:

PNG West has 17,537 customers that have their meters read in one of 8 cycles (bi-monthly) rather than at month end.

7.5.1 Please elaborate on how PNG performs meter reading and billing for these customers, and how frequently is this process carried out.

Response:

PNG performs metering reading once every two months for each of its 8 billing cycles. The meter reads are uploaded to the billing system once the meter readers complete their meter reading routes. As such, each of the 8 cycles is billed once every 8 weeks. Of the 17,537 customers that are bi-monthly read, only 11,699 are bi-monthly billed (the remainder are monthly billed and billed on estimates for non-read months).

7.6 Please explain whether an increase in the frequency in meter readings would improve the calculation of the unbilled estimate. Please explain the pros and cons of increasing the frequency of meter readings.

Response:

Increasing the frequency of meter reading does not change the fact that a portion of customers' meters are read on every working day of a calendar month. Unless all residential and small commercial customers' meters are read on the last day of the calendar month, PNG will need to continue to rely on an estimate of customers' demand from when their meter was read, to the end of the month in order to determine customer demand over a calendar month.

7.7 Please explain if the errors in unbilled estimates create offsetting UAF gas gains and losses. If they create both gains and losses, please elaborate on why this is contributing factor to overall UAF losses. If they only create losses, please explain why.

Response:

The unbilled estimate added to the residential and small commercial metered demand in each calendar month is reversed in the following month. Since the difference between the actual and estimated demand is reflected in either a UAF gain or loss in each month, the reversal of each estimate in the subsequent month will generate an offsetting UAF loss or gain. Therefore, over a calendar year, the contribution of errors in the unbilled estimate to the UAF volume for the calendar year is determined by the error in the December unbilled estimate, less the error in the unbilled estimate made in December of the previous year.

On page 8 of Appendix B to PNG-West's Amended 2018-2019 RRA PNG stated:

> The change in the unbilled DOS report created a one-time impact on the UAF volumes recorded in February and March, 2016. The impact of a cold snap in December 2016 on the unbilled estimate is an isolated event, albeit one that may occur again in the future….
>
> …..All of the excess UAF can be explained by isolated events affecting the UAF additions in February, March and December. A change in how the unbilled DOS are reported affected the UAF additions in February and March, and the unbilled estimate did not correctly reflect the impact of a cold snap in December.
>
> Through its diligent review of the causes of the UAF in 2016, PNG has achieved a high degree of confidence that these causes were isolated events affecting only three months during 2016, rather than systemic issues that may continue to result in UAF volumes that are higher than historic levels. The trend in UAF after December 2016 has returned to within historic boundaries, supporting PNG's position.

7.8 Please confirm whether PNG has corrected how the unbilled DOS are reported that led to the one-time impact on UAF volumes recorded in 2016.

Response:

PNG wishes to clarify that a change to the "Days of Service" (DOS) report made in Q1 of 2016 was not an error and was in fact an intentional change to the method for determining days of service aggregated across each of the residential and small commercial customer classes. The unbilled estimate is determined from the "Daily Average Consumption", calculated as described in the response to Question 7.1, multiplied by the DOS for that customer class. A one-time change to the DOS report therefore has an impact on the unbilled estimate that is not completely reversed in the subsequent month and, consequently, has an impact on the UAF volumes recorded in 2016. As stated in the preamble to this question, the impact on the UAF volumes is limited to the UAF volumes recorded in February and March 2016.

7.9 If the "trend in UAF after December 2016 has returned to within historic boundaries", please explain what has changed to warrant the increase in UAF loss percentage since December 2016.

Response:

Please see the response to Question 6.10. Deliveries on the PNG-West system in 2019 are approximately 30 percent lower as compared to 2009. On an absolute basis, the practical UAF floor of 1.5 percent, applied to the 2019 deliveries, results in a similar quantity of UAF – about 60,000 GJ – as the previous UAF floor of 1.0 percent applied to the 2009 deliveries.

7.10 Please identify and discuss any solutions available to PNG to reduce the errors in the unbilled estimate of monthly and bi-monthly billed customers. Please discuss the pros and cons associated with these solutions and why they have not been implemented.

Response:

Please see the response to Question 6.8.

8.0 Reference: COST OF GAS
Exhibit B-2, Section 2.2.3, p. 31
Unaccounted for Gas – Measurement Error, Linepack Error and Blowdown and Venting Estimates

8.1 Please elaborate on what is meant by Linepack error and Blowdown and Venting Estimates, how these are estimated and how they impact UAF losses.

Response:

PNG accounts for changes in line pack and gas lost through blowdowns and venting when determining the UAF gain or loss. However, errors in these estimated quantities end up reflected in the UAF gain or loss.

PNG estimates the quantity of natural gas evacuated to atmosphere during blow downs based on the physical dimensions of the evacuated section of pipe and the operating pressure. Inaccuracies in the estimated length of pipe, small deviations in the pipe diameter from that used in the estimate and errors in the measured pressure in the pipe segment all contribute to the error in the blow down estimate.

PNG maintains numerous pieces of equipment in its compressor and regulating stations that are actuated, or "powered" by natural gas. Some of this gas is released in the course of normal equipment operation. PNG estimates the amount of gas vented in the course of normal compressor station operations based on equipment specifications and an estimate of the number of times the equipment is operated. Errors in this estimate, while not considered to be large, also contribute to the unaccounted for gas volumes.

Finally, the quantity of natural gas in the PNG-West transmission system (the "line pack") is estimated on a daily basis using a hydraulic model based on metered flows and pressures along the pipeline. The nature of PNG's current operations of the PNG-West system – where the compressor at Station R1 is run only intermittently – results in large pressure gradients along the pipeline as the compressor is started and subsequently stopped. The impact of these gradients on the line pack are difficult if not impossible to predict accurately.

8.2 For each of the blowdown and venting estimate error, measurement error and linepack error presented in Table 15, please explain if these drivers create offsetting UAF gas gains and losses. If they create both gains and losses, please elaborate on why this is contributing factor to overall UAF losses. If they create losses only, please explain why.

Response:

The blowdown and venting estimate error, measurement error and line pack error presented in Table 15 of the Amended Application are uncorrelated to each other, meaning that, in any given period, positive errors in one component – those that overstate the quantity of that component – may be partially or wholly offset by negative errors in another component. The aggregate effect of all of the errors in the components may therefore be less than their sum total. However, PNG expects that a cumulative stacking of errors in the manner presented in Table 15 is an outcome that can be reasonably expected and should be used as a basis for determining the theoretical and practical bandwidth of UAF that PNG should expect to encounter over a 12-month period.

D. OPERATING EXPENSES

9.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3, p. 34
Operating Expenses

On page 34 of the Amended Application, PNG provides a breakdown of operating expenses in Table 16 and states that "operating expense line items have been presented net of shared service cost recoveries of expenditures for specific items."

9.1 Please revise Table 16 to show the gross operating expenses before the shared service cost recoveries from Pacific Northern Gas (N.E.) Ltd. (PNG(NE)) and provide an explanation for any significant variances for 2018 and 2019 (Decision and Actual) and the year over year changes from 2019 actual to 2021 forecast, where not already provided in the Amended Application.

Response:

PNG notes that the variances referred to in this question, i.e. "2018 and 2019 (Decision and Actual)" and "2019 actual to 2021 forecast" do not align with the information presented in Table 16 of the Amended Application. The response that follows focuses on the variances presented in Table 16, i.e. Decision 2019 to Test Year 2020 and Test Year 2020 to Test Year 2021.

Please see Revised Table 16 below, showing gross costs before shared service cost recoveries from PNG(NE). The only two line items impacted by this change are BCUC Account 685 – General Operations and BCUC 711/713/714 – Customer Care.

Revised Table 16: Forecast Operating Expenses (Gross)

	$000's											
BCUC Account	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
		$	%		$	%						
665 - Pipelines	2,696	(642)	(19.2)%	3,338	1,557	87.4%	1,781	1,672	1,813	2,040	1,805	1,720
666 - Compressors	648	14	2.1%	635	146	29.8%	489	557	450	559	601	498
667 - Regulating Stations	235	5	2.2%	230	5	2.4%	224	240	249	210	213	237
670 - Supervision	545	12	2.2%	533	(10)	(1.8)%	543	661	629	572	591	603
685 - General Operations	4,639	414	9.8%	4,224	308	7.9%	3,916	2,922	3,813	3,186	3,052	2,980
688 - Other General Operations	2,087	69	3.4%	2,018	309	18.1%	1,709	1,895	1,752	1,683	1,683	1,404
711/713/714 - Customer Care	1,956	213	12.2%	1,743	89	5.4%	1,654	1,662	1,547	1,572	1,525	1,512
Other inc. 673/675/684/712/718	2,195	191	9.5%	2,004	170	9.3%	1,834	1,812	1,600	1,809	1,771	1,794
Operating Expenses	**15,001**	**276**	**1.9%**	**14,725**	**2,576**	**21.2%**	**12,149**	**11,421**	**11,853**	**11,631**	**11,241**	**10,748**
Less: Cost of Gas - 665 Pipelines	(559)	(68)	13.8%	(491)	(162)	49.1%	(330)	(383)	(295)	(372)	(278)	(369)
- 685 General	(9)	(1)	10.3%	(8)	(0)	0.6%	(8)	(3)	(3)	(6)	(4)	(7)
Cost of Gas	**(568)**	**(69)**	**13.8%**	**(500)**	**(162)**	**47.9%**	**(338)**	**(386)**	**(298)**	**(378)**	**(282)**	**(376)**
Operating Expenses (Net of Company Use Cost of Gas)	**14,433**	**207**	**1.5%**	**14,226**	**2,414**	**20.4%**	**11,811**	**11,035**	**11,555**	**11,253**	**10,959**	**10,372**
Less: Transfers to Capital	(699)	(42)	6.4%	(657)	(147)	28.8%	(510)	(510)	(543)	(397)	(362)	(314)
Net Operating Expenses (Net of Transfers to Capital)	**13,733**	**165**	**1.2%**	**13,569**	**2,267**	**20.1%**	**11,301**	**10,525**	**11,012**	**10,856**	**10,597**	**10,058**

PNG has prepared the tables that follow to compare the variance between Decision 2019 and Test Year 2020 and between Test Year 2020 and Test Year 2021 for each of BCUC Account 685 – General Operations and BCUC 711/713/714 – Customer Care, on a net basis as per the Amended Application and on a gross basis, as per the table above.

	$000's						
BCUC Account	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019
		$	%		$	%	
685 - General Operations	3,513	285	8.8%	3,228	212	7.0%	3,017
685 - General Operations - Gross	4,639	414	9.8%	4,224	308	7.9%	3,916

	$000's						
BCUC Account	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019
		$	%		$	%	
711/713/714 - Customer Care	1,058	196	22.8%	862	57	7.1%	805
711/713/714 - Customer Care - Gross	1,956	213	12.2%	1,743	89	5.4%	1,654

PNG observes that while the dollar and percentage changes on a gross basis differ from those computed on a net basis, the explanations for the variances remain consistent with those presented in the narrative provided in the Amended Application.

10.0 Reference: OPERATING EXPENSES Exhibit B-2, Section 2.3.1, pp. 35, 38. Account 665 – Pipelines

On page 35 of the Amended Application, PNG states that "Test Year 2020 costs of $3.338 million are forecast to increase $1.577 million or 87.4% over Decision 2019 costs of $1.781 million."

10.1 Please provide a breakdown of the 2018 and 2019 (forecast and actual), and Test Year 2020 and 2021 Account 665 – Pipeline costs for the following categories: ILI Tool runs, investigative digs and repairs, third party system integrity costs, costs for transitioning operation strategy from reactive to proactive, right of way clearing and any other relevant cost categories. Please also provide an explanation for any significant variances, if not already provided in the Amended Application.

Response:

Please see the table that follows.

($'s)	Forecast 2021	Forecast 2020	Decision 2019	Actual 2019	Decision 2018	Actual 2018
In-line Inspections/Pigging/CIS/DCVG	196,000	889,000	113,000	238,000	134,000	585,000
ILI/CIS/Digs Deferral (665 offset)	n/a	n/a	n/a	- 33,000	n/a	- 88,000
Investigative Digs	608,000	594,000	521,000	430,000	511,000	148,000
ROW Clearing	540,000	530,000	292,000	272,000	286,000	223,000
SCADA	255,000	250,000	245,000	220,000	240,000	227,000
Pipeline Patrols	63,000	62,000	61,000	47,000	60,000	45,000
Airborne Laser Methane Assessment	69,000	68,000	103,000	59,000	101,000	-
Above Ground Asset Inspections (valve sites, pressure sites, arial bridges, etc)	102,000	100,000	115,000	included in other category	113,000	included in other category
Geohazard ID and Management	209,000	204,000	-	-	-	-
System Integrity Engineering Support	104,000	102,000	-	-	-	118,000
Kitimat Lateral Integrity & Decomm	107,000	105,000	-	-	-	-
Wildfire Protection PNG Assets						37,000
Other	443,000	434,000	363,000	438,000	335,000	519,000
Total	2,696,000	3,338,000	1,813,000	1,671,000	1,780,000	1,814,000

PNG submits that all significant variances in costs noted in the table above have been addressed in the Amended Application and/or in responses to subsequent related questions.

On page 38 of the Amended Application, PNG states that "[f]ollowing on activities undertaken in 2018 and 2019, PNG-West has planned further expenditures for Test Year 2020 and Test Year 2021 to perform initial assessments and to develop a management system that would transition its operation strategy from reactive (emergency response) to proactive (prioritized prevention)."

10.1.1 Please elaborate on the management system developed and the activities to transition the strategy from reactive to proactive in nature.

Response:

PNG believes it is important to comply with pipeline integrity regulations and to develop management systems that improve asset and integrity management. The energy industry's approach to making such improvements involves developing and maturing systematic management practices and programs to enable proactive vs. reactive operations by way of investment and continuous improvement.

Since the loss of major customers in the early 2000's, PNG has consciously made some risk-based decisions to defer maintenance and integrity work due to cost pressures, but this approach can lead to higher numbers of unplanned failures. Today, PNG is facing an elevated risk of pipeline incident and regulatory non-compliance. The Company also recognizes that it has aging infrastructure and is operating in an environment with heightened regulatory requirements and stakeholder expectations with respect to integrity management.

Thus, the "management system" described in this Amended Application is a generic, collective, and overarching term to describe the suite of Asset and Integrity Management System improvements, business practices, and management strategies to better manage and prioritize risks, which include but are not limited to the following:

- **Segment-by-Segment Risk Assessment:** In 2019, PNG commenced a project to complete a more granular and quantitative risk assessment of its entire high pressure pipeline system on a segment by segment (or line by line) basis. Each pipeline licensed by the BC Oil and Gas Commission (BCOGC) will be assessed by third party Subject Matter Experts (SMEs) for risk relative to the threats and consequences outlined in the American Society of Mechanical Engineers (ASME) B31.8S "Managing System Integrity of Gas Pipelines" and accepted within the industry as standard.

- **Management of Change (MoC)**: PNG is in the process of updating its MoC process. The MoC process establishes guidelines and minimum requirements for managing temporary or permanent changes to process, facilities, technology, equipment, and personnel changes to facilities. MoC provides guidance to ensure that various considerations are addressed prior to any change.

- **SCC Management Program:** PNG is developing a comprehensive program to perform EMAT (Electro Magnetic Acoustic Technology) inspection over the next five years throughout the entire PNG-West transmission system. EMAT tools have recently become available for smaller diameter pipelines, whereby early signs of Stress Corrosion Cracking (SCC) can be more readily identified, repaired or cut out. PNG has successfully performed two EMAT runs to date.

- **Geohazards Management Program:** PNG aims to develop a more formalized program to support a proactive, repeatable and defensible approach to managing geohazards, such as river erosion and ground movements from landslides and seismicity. This type of program involves generating a list of potential geotechnical and hydrotechnical hazard sites, assessing the risks of each site, and developing a long-term program to mitigate risk geotechnical failures.

- **Computerized Maintenance Management Systems (CMMS):** PNG is implementing the Maximo system to support the planning and scheduling of all associated preventative maintenance and capital work. Maximo provides comprehensive support of PNG assets, maintenance, resource, and parts supply chain management needs. The CMMS provides enterprise asset management software for long and short-term planning, preventive, reactive and condition-based maintenance, schedule management, resource optimization and key performance indicators.

- **Contractor Management Plan (CMP):** As an additional means of recognized risk reduction, PNG has made improvements to overall contractor management via the incorporation of a formalized Contractor Management Program (CMP). The CMP provides direction on the procedures required by PNG to not only ensure the health and safety of contracted employees and environmental protection during the contracted work, but also to ensure work quality and risk minimization to existing PNG assets.

- **Geographical Information System (GIS):** PNG is nearing the completion of the implementation of its GIS to increase its asset management capacity and capabilities. Implementing GIS technology provides PNG with opportunities for streamlining and standardizing business processes to improve process efficiency and consistency between geographic locations, integrate with key business systems, improve communication and streamline workflows within PNG.

- **Security Management Plan:** In 2019, PNG commenced work on a project to improve overall asset security and better align with industry trends associated with overall security management of oil and gas operations. The resultant Security Management Plan (SMP) will have the objective of providing the security framework around PNG's assets, in compliance with regulatory requirements, to support PNG's security management planning and emergency management.

- **Emergency Response Plan:** PNG has had to make improvements to its Emergency Response Plan (ERP) in recent years. The codes, standards and regulations have increased with respect to ERP's, and PNG has also had a disproportionate number of emergencies on its high-pressure pipeline over the years. In 2017, PNG was lagging with respect to industry ERP practices, among other integrity processes, which was evidenced by a relatively poor assessment in 2016 from the BCOGC. PNG has invested in its planning, exercises and training since then. In 2019, PNG received a strong positive audit result from the BCOGC given recent drastic improvements.

10.1.2 Please provide a breakdown of the actual 2018 and 2019 and forecast 2020 and 2021 and beyond costs associated with developing the management system between third-party expertise costs and other costs.

Response:

The table provided in response to Question 10.1 illustrates the year-by-year cost increase associated with transitioning PNG's focus on integrity management and proactive compliance-based activities.

The table below provides a breakdown of the most notable third-party expertise costs for developing the management systems that are included in the 2020 and 2021 forecasts.

Management System Element	2018	2019	2020	2021
Segment by Segment Risk Assessment	$nil	$5,000	$125,000	$10,000
MoC	$nil	$50,000	$75,000	$10,000
SCC Management	$nil	$100,000	$200,000	$200,000
Integrity SME Support	$300,000	$160,000	$100,000	$100,000
Geohazard	$135,000	$83,000	$200,000	$200,000
CMMS	$212,000	$96,000	$40,000	$nil
CMP	Internal only	Internal only	Internal	Internal only
GIS (project only)	$670,000	$1,028,000	$697,000	$nil
SMP	$nil	$53,000	$50,000	$50,000
Emergency Response	$139,000	$226,000	$150,000	$188,000

10.1.3 Please elaborate on the benefits realized as a result of the activities completed to date and the expected future benefits.

Response:

Because the activities, efforts, investment of resources, and intended outcomes are largely compliance based, the benefits of the activities to date are considered to be increased certainty of compliance, improved regulator relationships, and decreased potential for incidents and/or regulator intervention. Future benefits are considered largely to be the same, as well as the cost avoidance afforded by proactive avoidance of incidents vs. emergency reactive response in unplanned conditions.

11.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.1 p. 35
Account 665 – Pipelines – Integrity Management Plan

On page 35 of the Amended Application, PNG states:

> The majority of the test year cost increases over Decision 2019 relate to ensuring compliance with PNG's Integrity Management Plans and related codes, standards and regulations.

11.1 Please provide PNG's Integrity Management Plan.

Response:

PNG has appended its 2014 Distribution Integrity Management Plan as "Attachment BCUC 1.11.1 - Distribution Integrity Management Plan (2017)" for reference and notes that it is in the process of updating this plan.

11.1.1 Please elaborate how compliance to this plan and related codes, standards and regulations have impacted test year pipeline operating expenses. For example, have there been changes to the codes and standards, or have pipelines been recently identified as non-compliant? Please discuss.

Response:

PNG recognizes the pipeline operating expenses have increased appreciably from previous years. The factors that are driving the increases relate to: 1) heightened codes, standards, regulations relating to pipeline integrity; 2) heightened stakeholder expectations; 3) aging infrastructure; and 4) re-focussing PNG to "catch-up" on previously deferred maintenance and integrity work.

1) Changes to Codes, Standards and Regulations

There have been recent integrity management associated changes to CSA Z662, with a new edition release in 2019. This standard is the fundamental standard governing natural gas pipeline design, construction, maintenance, and integrity management and guides operational expectations of both the BC Oil and Gas Commission (BCOGC) and Technical Safety BC (TSBC). Furthermore, there have been changes in the US by the Pipeline and Hazardous Materials Administration (PHMSA) that are shaping changes with Canadian and provincial technical regulators. There is also an increasing focus on the meaningful application of standards such as CSA Z663 for land use planning and the management of third party activities, CSA Z260 on pipeline safety metrics, CSA Z246 on oil and gas facility security and loss management, CSA Z247 for damage prevention, and API 579 fitness for service.

These noted changes have resulted in direct and appreciable focus and mandated requirements by the BCOGC pertaining to pipeline segment by segment risk management and the implementation of a new assessment and audit program directed at pipeline and facility assets 50 years of age or older, thereby encompassing many of PNG's transmission system assets. This has resulted in, but is not limited to, increasing focus, efforts and expenses by PNG in medium and high consequence areas, geohazard identification, monitoring and management, small diameter and hard to inspect pipelines, verification of maximum operating pressure acceptability for in-service pipelines, and class location changes.

Advances in technology in all aspects of pipeline system access, inspection, and integrity management have also contributed to both the increase in expectations as well as operators' abilities to respond. These improvements in technology have paved the way for the applicable codes and standards to become more prescriptive in terms of acceptable means for things such as depth of cover surveys, in-line inspections, and leak detection.

Given all of this, PNG's overall understanding and appreciation for integrity management-based requirements continues to mature and broaden and with this comes changes to operational practice and associated expense to ensure compliance and continued responsible operation as it pertains to pipeline safety and reliability.

2) Heightened Stakeholder Expectations

There is a general and progressive expectation by the public, by regulators, and by the industry for continuous improvement in pipeline and facility operating practice and strategy as it pertains to

integrity management. This is emphasized by the creation, sustainment, and increased investment of resources in best practices committees, associations, conferences, and other forums focused on pipeline system and facility safety and integrity such as CGA standing committees for operations, CEPA, International Pipeline Conference, Pipeline Pigging and Integrity Management user groups, and internally by TriSummit Utilities Inc. (formerly ACI) best practices committees on integrity. Through ongoing and increased involvement in such committees, conferences, and associations, PNG improves its understanding of the intent of integrity management overall and better align to the associated industry and regulatory driven changes in expectation and practice. These changes in expectation are also partially driven by integrity-related incidents internally, provincially, nationally, and internationally; changes to codes and standards and our appreciation for them; and changes to or implementation of new integrity compliance-based regulator monitoring and management programs and initiatives.

Examples of recent and well-known pipeline integrity related incidents that have highlighted associated risk and elevated awareness and expectation are the following:

- San Bruno Pipeline Explosion occurred on September 9, 2010, in San Bruno, California, when a 30-inch (76 cm) diameter steel natural gas pipeline owned by Pacific Gas & Electric exploded into flames in a residential neighborhood. There were eight fatalities. The investigation found numerous defective welds in the pipeline. The thickness of the pipe varied, and some welds did not penetrate the pipes completely. As PG&E increased the pressure in the pipes to meet growing energy demand, the defective welds were further weakened until their failure. The pipeline was installed in 1956.
- On September 13, 2018, excessive pressure in natural gas lines owned by Columbia Gas of Massachusetts caused a series of explosions and fires to occur in as many as 40 homes, with over 80 individual fires, in the Merrimack Valley, Massachusetts, towns of Lawrence, Andover, and North Andover. One person was killed and 30,000 were forced to evacuate their homes.
- 2018 Enbridge Natural Gas Transmission Line Rupture near Prince George, BC. Pipeline rupture of a polyethylene tape coated pipeline occurred as a result of Stress Corrosion Cracking (SCC) that had gone undetected in a pipeline that was subject to a deferred in-line inspection.
- On February 12, 2020 the Canadian Energy Regulator (CER) released Safety Advisory SA 2020-01 to advise on the topic and concern of girth weld area strain-induced failures in high tensile strength pipe subject to environmentally induced loading such as geotechnical failure. This gained specific subsequent attention of the BCUC, with a letter dated March 5, 2020 being sent to PNG asking specific questions related to PNG's potential for similar risk and for confirmation of a fully compliant integrity management plan. PNG responded that it was not presently at risk of similar strain-induced girth weld failures based on knowledge of the various programs (line patrols, geohazard ID and management, right of way clearing, unspecified mainline repairs) within the PNG Integrity Management Plan that are focused and subject to continuous improvement around monitoring, prevention, and response to emerging issues that could result in contributing and unintended externally applied environmental loads.

3) Aging Infrastructure

PNG's infrastructure has aged to the point of where significant repairs are required to extend the useful life. PNG's original western transmission line is over 50 years old as it was commissioned in 1968.

While aging infrastructure can be operated safely and reliability, it is critical to make the necessary investments in ongoing O&M and Betterment capital. The BCOGC has also drawn focus to "aged pipelines" and recognized the elevated risk by undertaking specific assessments on aging pipelines in BC.

4) Catch-up on Deferred Maintenance and Integrity Work

Over the past 20+ years, PNG has attempted to strike a responsible balance between spending on integrity programs and addressing rate impacts. In some cases, PNG elected to defer improvement work in order to minimize rate increases. This may have resulted in potential concerns with respect to codes, standards, and regulations; however, PNG has attempted to address these issues in this Amended Application and plans to do so further in future CPCN applications.

All of the points noted above have resulted in the increases in operating and maintenance expenses, as well as capital programs as reflected in the Amended Application.

11.2 Please discuss any risks associated with delays to the timing of execution of these pipeline integrity activities.

Response:

As presented in response to Question 11.1, all changes to and improvements in the execution of PNG's pipeline integrity activities are technical regulator driven, many of which are closely linked to a unified pipeline industry response to incidents, failures, identified flaws and areas of concern. Delaying activities increases the risk of a PNG-related incident and subjects PNG to the scrutiny of the BCOGC and TSBC during inspection and audit activities, particularly in relation to aging infrastructure. PNG also notes that it will be subject to a full and formal integrity management program audit by the BCOGC in 2020.

As PNG's IMP is based around regulatory compliance (Z662, TechSafeBC, ASME, etc.), and activity intervals are specified in these regulatory documents, any delays to the execution of items in the IMP will not only result in non-compliance, but could negatively affect the integrity of PNG's assets, with the risk of deleterious incidents increasing. As with any pressurized natural gas transmission line, the result of unwanted incidents on PNG's line could affect the safety of employees, public, the environment, and to a lesser extent, create additional strain on our rate payers for subsequent repairs.

12.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.1 p. 36
Account 665 – Pipelines – Transmission Integrity Management Plan

12.1 Please provide PNG's Transmission Integrity Management Plan (TIMP).

Response:

PNG submits its current version of its TIMP which encompasses both pipelines and associated facilities as "Attachment BCUC 1.12.1 - Transmission Integrity Management Plan (2014)".

With the 2019 update to CSA Z662, including changes specifically associated to integrity management within the standard and its associated Annexes, PNG's integrity management plans and programs will be subject to a formal audit by the BC Oil and Gas Commission in 2020. The TIMP provided is scheduled to be updated within the current test period.

13.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.1 p. 36-37
Account 665 – Pipelines – ILI Tool Runs and Investigative Digs

On page 36 of the Amended Application, PNG states:

> The forecast cost for running the inspection tool varies based on the length and diameter of the pipeline being inspected in any given year. Each year PNG-West requests quotes from third party vendors for performing this activity on identified segments of pipeline and it is this information that is the basis for the forecast cost included in this Amended Application…
>
> Forecast costs for pipeline inspection activities is $961,000 for Test Year 2020 and $272,000 for Test Year 2021, compared to costs of $176,000 forecast for Decision 2019. PNG-West notes that there were no expense-based ILI runs carried out in 2019…
>
> The main rehabilitation activities used to follow-up on the findings of the ILI tool runs are investigative digs and repairs, or pipe replacement. For Test Year 2020, the forecast expenditure for investigative dig activity is $614,000, compared to $558,000 forecast under Decision 2019. Costs for Test Year 2021 are forecast to be $628,000.

13.1 Please provide additional information regarding the process to obtain quotes. Specifically, please address whether it is an open bidding process or whether PNG invites pre-qualified vendors to submit pricing.

Response:

PNG invites industry qualified and reputable vendors suited to our pipeline systems to submit bids under a formal Request for Proposal process. The bidders are unknown to each other, all are equally privy to the clarifications requested during the response process, and all proposals are submitted on PNG templates in accordance with PNG's in-line inspection, specific terms and conditions. Once proposals are received, PNG performs a thorough bid evaluation that factors in many criteria other than bid price before proceeding with a successful vendor.

13.1.1 Does PNG have capacity to complete the ILI runs using internal resources? If not, please discuss if PNG has assessed the feasibility of doing so.

Response:

PNG does not have the capacity to complete ILI runs using internal resources, although PNG notes that the ability to complete runs does require significant involvement by PNG resources for support services. ILI runs are a very technical and precise specialty service, requiring numerous technicians and analysts both in the field and office based pre-, post-, and during the run(s) with specialized training in tool technology, run requirements associated with gas flow pressure and velocity, and geospatial tracking. In addition to the extensive resources allocated by PNG (field pipeline crews and engineering and management), tool vendor and supplementary third party support teams through an ILI project life cycle will top 15+ persons. Furthermore, the most basic of ILI tools suitable to PNG's pipeline integrity needs have replacement values in excess of $2 million, are technologically complex and delicate, and are purpose-built for each unique pipeline inspection. As a result, PNG has assessed the feasibility of self performing ILI runs and has concluded that it is not feasible.

Despite the above, PNG currently staffs at a level that is capable of supporting an ILI run with field personnel providing labour (physically laying out monitors, operating valves, assisting with launch/receive, general labour, etc). PNG, as with most pipeline operators, does not have the resources, tooling, or expertise to perform ILI runs completely 'in-house', and as such relies on a competitive bidding process with a group of prequalified, reputable, third party vendors to perform the ILI. PNG notes that it is also seeking approval for an internal Integrity Engineer, who can provide technical analysis, engineering support, and vendor management for some of the aforementioned activities.

13.2 Please discuss the specific activities and costs for the ILI tool runs and investigative digs that are capitalized and expensed and the rationale for the accounting treatment.

Response:

PNG notes that the accounting treatment for all the activities and costs related ILI tool runs and investigative digs have been addressed in prior revenue requirements application decisions as follows:

- ILI runs are normally expensed in the year incurred, except for the EMAT ILI tool as noted below. This is in accordance with US GAAP. Variances are recorded in a deferral account to be amortized the following year.
- EMAT runs – this pertains to a fairly new ILI tool for transmission pipelines first introduced in PNG's 2016-2017 Revenue Requirements Application and further addressed in the 2018-2019 Revenue Requirements Application . Based on Orders G-131-16 and G-151-18, PNG was directed to capitalize these costs and depreciate them over a 10 year period which is in compliance with US GAAP.
- Investigative Digs – this was specifically addressed in the 2013 Revenue Requirements Application Decision under Order G-114-13 and PNG was directed to record its forecast for investigative digs in its cost of service starting in 2013 and create a new deferral account to capture any variances to be amortized the following year.

13.3 Please provide the following information in table format for each year (decision and actual) between 2015 and 2019 and forecast 2020 and 2021:

- ILI tool runs expensed
- Investigative digs expensed
- Capitalized costs for ILI tool runs
- Capitalized costs for investigative digs
- Number of executed ILI tool runs and investigate digs

Response:

The requested information is provided in the table that follows.

	2021	2020	2019		2018		2017		2016		2015	
	Forecast	Forecast	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual
Number of executed ILI tool runs	3	4		-		2		-		3		2
Total Expensed ILI Tool Runs	196,000	889,000	113,000	238,000	134,000	585,000	160,000	75,000	231,000	204,000	220,000	178,000
Total Capitalized ILI Tool Run Costs	2,893,975	2,174,062	-	334,188	1,232,474	1,270,891	-	-	462,961	484,950	-	-
Number of Executed Investigative Digs				41		36		106		203		211
Total Expensed Investigative Dig Costs	608,000	594,000	521,000	430,000	511,000	148,000	500,000	277,000	489,000	535,000	488,000	467,000
Number of Executed Capitalized Repairs				12		14		9		2		8
Total Capitalized Repair Costs Resulting from Investigative Digs	**1,042,475**	1,020,905	199,202	583,310	195,700	449,023	370,370	189,245	363,609	43,140	323,657	133,289

13.3.1 Please provide an explanation for any significant variances between forecast and actual costs (and number of cut outs and digs) and any significant increases year over year that are not already provided in the Amended Application.

Response:

As supplement to the extensive discussion provided around Account 665 variances and cost increases within PNG's Amended Application, PNG submits the following additional explanations.

Expensed ILI Runs

2017 – The Decision amount was based on budgeting that gave primary consideration to the average cost of previous years' completed inspections, adjusting the 2017 amount based on run length variability. It did not sufficiently consider specific complexities of access and terrain associated with the pipeline segment planned for inspection. During inspection preparation works in late Q3 and early Q4 that included considerable helicopter access for brushing and Above Ground Marker (AGM) box placement, PNG encountered persisting fog and inclement weather conditions that ultimately resulted in an inability to complete the inspection. Actual costs incurred in 2017 were limited to preparations works, some of which would be incurred again in 2018 with the eventual deferral of the intended inspection.

2018 – The Decision amount was based on an expectation that the inspection planned for late 2017 would have appreciable carry forward costs into 2018, including invoicing for trailing costs associated with 2017 year end field work and for the 2018 planned receipt of the inspection run final reporting. Actual costs were a result of the 2017 planned inspection being deferred as a result of weather constraints and the run being much more challenging, complex, and higher cost than originally budgeted from a terrain and remoteness related access (primarily helicopter) and survey and tool tracking perspective. Additionally, costs associated with support from external inline inspection and integrity management Subject Matter Experts (SMEs) were incurred that were not considered in the original decision but are to be expected as part of future budgets and requests, including the 2020 and 2021 Test Years.

2019 – The Decision amount was limited to the anticipated cost of the 2018 inspection run final report delivery. In addition to this cost, additional expense in 2019 was associated with trailing invoices from the 2018 inspection and sustained SME involvement in anomaly data review and prioritization for future address by way of investigative digs and repair.

2020/2021 Forecasts – The planned inline inspection in 2020 traverses remote and extreme coastal terrain, including the crossing of the main stem and multiple side channels of the mighty Skeena River, requiring special environmental and fisheries sensitivities considerations during access and brushing on multiple river islands and when crossing or in proximity to fish bearing streams on the mainland. Portions of access will be via helicopter and river boat and mature timber is expected to be encountered when clearing helicopter landing pads. Appreciable external SME integration into the ILI project team will be required, including ILI and integrity specialists and Qualified Environmental Professionals (QEPs). The 2020 forecast has been based closely off actual costs incurred for the 2018 inspection due to their appreciable similarities, including being physically adjacent segments of the

same pipeline. The 2021 forecast is limited to the expected cost of delivery of the final inspection report and sustained SME support.

Capitalized ILI Runs - EMAT

2019 – Variance was due to unbudgeted cost associated with delay in delivery of the final report for the 2018 electromagnetic acoustic transducer (EMAT) run.

2020/2021 Forecasts – Anticipated increases in cost relative to previous years that included capitalized EMAT inline inspections are attributed to the fact that 2020 and 2021 will be the first years that more than one capitalized ILI run will be completed in a given calendar year, with three EMAT runs in each year. Furthermore, these runs will be at various locations throughout the PNG-West system and are of various pipeline diameters and lengths. This results in additional costs for repositioning throughout the system and the mobilization/demobilization and associated cost of multiple tools and crews. Costs associated with the delivery of the final report for the 2020 EMAT runs have been accounted for in the 2021 forecast.

Expensed Investigative Digs and Capitalized Repairs

The variance seen across the 5 years of investigative dig and capitalized repair costs can be explained as follows:

2015-2017: Up to 2017, PNG's approach to integrity inspection and repair was to treat all inspection with equal priority, inspecting all features of 10% metal loss or greater, dents, and coating disbondment, for example, linearly across the pipeline starting at one end of the segment and working down or up chain. This resulted in a significant focus on investigative digs (as evidenced by the high number of dig sites) and a significant underspend on repairs, with much of the construction season and resources being expended performing high volume, low cost, digs and often assessing high quantities of non-injurious pipeline features with repairs limited to coating re-wrap application. Cost and effort per dig site overall were low given the linear nature of the work and the close proximity of many of the investigation sites, resulting in minimal need for repositioning of equipment and resources throughout the construction season.

2018/2019: PNG attempted to correct the previous years' underspend by decreasing the forecast amounts for both 2018 and 2019. However, this time period corresponded to a shift in focus on integrity management and a change in approach to investigative digs and repairs, with a focus on dig site prioritization in order to ensure the most potentially injurious anomalies and pipeline defects were being addressed as immediately as possible with given budgets and schedule. The result was a misguided decrease in forecast amounts in the presence of an increased number of focused high priority repairs, and ultimately an increase in actual incurred cost (overspend variance).

2020/2021 Forecasts: PNG expects a high volume of both inspections and repairs stemming from planned magnetic flux leakage (MFL) and EMAT ILI inspections, as well as to continue work on inspection backlog activities. Continuing with the approach and trend established in 2018/2019, PNG will prioritize activities around the most potentially injurious pipeline anomalies and defects in order to continue to improve the value of associated efforts. Repairs are expected to include a significant amount of cutout repairs associated with Stress Corrosion Cracking (SCC) and dents in geohazard areas,

and a high cost of access to repair as they are in remote areas of the pipeline system. Third party resources are expected to be integral to the inspection and repair effort, supplementing internal crews and providing specialty non-destructive evaluation (NDE) and integrity assessment support.

13.4 Please clarify how the forecast operating expenditures for investigative dig activities are determined.

Response:

Historically up to 2017, the forecast operating expense for investigative digs has been based on a rolling average of the preceding 5 years of actual expense. Starting with the 2018-2019 Revenue Requirements Application , more direct consideration was given for the pipeline sections planned for inspection (length, diameter, run quantity), the ILI tool technologies planned for use, and the prioritized dig quantities expected to be generated from a given ILI run. Pipeline diameter, length, known coating material and condition, terrain, and tool technology of use all contribute to the expected quantity of required investigative digs. The use of advanced combination MFL tools using both axial and circumferential (or spiral) orientations, as well as EMAT tools, has contributed to forecasted costs increasing considerably. Additionally, as evidenced by discussion in response to Questions 11.1 and 11.2, the need for completing past due investigative digs (where required dig quantity outpaced requested budgets) could no longer be deferred. This has also been accounted for in the most recent budget requests and forecasts.

Furthermore, with the incorporation of EMAT inline inspection for crack and other linear anomaly detection, additional speciality NDE and integrity assessment resources are required during investigative digs. These requirements have been accounted for in the most recent forecasts.

14.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.1 p. 38
Account 665 – Pipelines – System Integrity Support and Geohazard Identification and Management

On page 38 of the Amended Application, PNG states that it has forecast approximately $100,000 for each of Test Year 2020 and 2021 for third-party system integrity support and approximately $200,000 for each of Test Year 2020 and 2021 for third-party support to execute geohazard risk management activities.

14.1 Please elaborate on the type of third-party system integrity support PNG is seeking (e.g. risk assessment, material expertise, data analysis, etc.).

Response:

With advancing expectations around integrity management and associated continuous improvement, PNG expects to leverage third party support for ongoing improvements to the PNG DIMP and TIMP documentation, and associated programs, in order to align more completely with the newest release of CSA Z662 and its Annex N. Support is also expected to be leveraged for IMP audit preparation, risk assessments, fitness for service assessments, development of new and/or improved inspection programs and processes for small diameter and hard to inspect pipelines and facility assets (sub-sea pipelines, pressure vessels, tanks), and data analysis and response support.

14.1.1 Please provide historical actual system integrity and geohazard risk management support costs from third parties (five year).

Response:

The following table provides the five-year historical actual costs incurred for system integrity and geohazard risk management support from third parties. Select capitalized costs have been included for relative reference purposes given that under slightly different circumstances in the absence of coincidental and directly applicable capital projects these costs would have been / would be expected to be incurred as operating expenses. PNG notes that the five-year historical actual costs are not necessarily a useful decision-making tool, particularly in the earlier years, given the external and internal changes with respect to pipeline integrity impacting PNG (Please see the response to Question 11.1.1 for further explanation).

Account 665 - Pipelines	**2015**	**2016**	**2017**	**2018**	**2019**
Integrity Management Support			$ 105,582	$ 20,629	$ 178,038
Geohazard Management Support	$ 5,140	$ 680			$ 3,489
Account 685 - System Ops & Eng					
Integrity Management Support				$ 118,000	$ 24,846
Geohazard Management Support					
Other - Capitalized					
Integrity Management Support				$ 163,615	$ 59,281
Geohazard Management Support				$ 135,611	$ 79,897
Totals					
Integrity Management Support			$ 105,582	$ 302,244	$ 262,165
Geohazard Management Support	$ 5,140	$ 680		$ 135,611	$ 83,386

PNG also notes that there is budget allocation for the addition of PNG integrity engineering head count (1 FTE) in 2020 that will help provide some future relief to, but not eliminate, the rate of growing costs associated with external integrity management resources. As discussed throughout the Amended Application and associated IR responses, there continues to be growing focus within the pipeline industry and from PNG regulators and stakeholders, around overall integrity and geohazard management and a resultant increased focus by PNG management on compliance and best practices and continuous improvement as it pertains to safe and reliable pipeline operation. As such, integrity and geohazard management support costs are expected to increase or in the least be sustained, while being supplemented and managed by a PNG internal subject matter expert.

15.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.1 p. 38
Account 665 – Pipelines – Right of way clearing

On page 38 PNG states "ROW clearing is primarily undertaken by contractors as PNG-West is not equipped to undertake the activities with internal resources."

15.1 Please clarify the portion of right of way clearing attributed to contractor costs.

Response:

Contractor costs forecast for right of way clearing for the test period include:

	2020	2021
Contractor	$ 454,000	$ 463,080
PNG Internal	$ 59,286	$ 60,647

PNG-West is currently not equipped to perform ROW clearing in-house. Following a competitive bid process, PNG will select contractor operators and related machinery to perform the physical clearing of the ROW. Thus, the portion of ROW clearing costs attributed to 'contractors', is the hourly cost of the contractor machines and operators. In addition to the actual right of way clearing, contractor costs are attributed to survey of the ROW, riparian management area identification, and landowner notifications.

PNG notes that it uses modest internal labor for the locating of pipeline centreline and confirmation of depth of cover before allowing the brushing contractor(s) to proceed and advance. PNG field staff perform HSEQ inspection and management on the brushing contractors. In all instances of right of way clearing related contractor engagement, PNG seeks to find qualified local contractors and gives consideration within bid evaluation processes for those maintaining active Indigenous Nation partnerships. This provides for lowest cost solutions to resource needs, optimizes local economy impacts, and contributes to PNG's Environmental and Social Governance (ESG) objectives.

16.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.2, pp. 38–39
Account 666 – Compressors

On pages 38 and 39 of the Amended Application, PNG states:

> Forecast Test Year 2020 costs of $635,000 are $146,000 or 29.8% higher than Decision 2019 costs of $489,000. Compressor work planned for 2020 is an integrity management activity on the gas coolers on the discharge of the R1 Compressor to ensure continued safe operation and maintenance of the compressor station. This pressure testing activity will be repeated at regular intervals, likely to be every 10 years.

16.1 Please provide the methodology for deriving the forecast cost in the Test Period.

Response:

The forecasted costs have been derived for the test period using historical spend profiles and then making projections for the test period, including appropriate budgetary adjustments for identified specific projects necessary to deliver safe and reliable service. The gas cooler and robotic inspection activities are examples of such projects.

16.2 Please clarify when this testing activity was last performed on the R1 Compressor and why the R1 compressor was selected for this pressure testing in Test Year 2020.

Response:

This testing activity has not been conducted on the R1 compressor since the coolers have been installed. With the increased focus on integrity management across the global gas industry, this inspection along with the other measures that PNG is introducing, demonstrates that PNG is being proactive in its approach to managing its assets.

The R1 compressor station is of critical importance to gas supply for the PNG-West system, being the sole supply route to the system with greater than 20,000 customers. R1 is an aged mechanical asset and a potential single point of failure for the entire system. The integrity of the site, and the equipment within, is a key risk that PNG must manage. This project and the Gas Robotic Agile Inspection Device (GRAID) project will allow the continued assessment of its equipment and provide PNG with valuable asset management data that it can utilise to effectively manage its assets on a go forward basis.

On page 39 of the Amended Application, PNG states that "[f]orecast expenditures are for a robotic inspection of the inside of the pipework utilizing a new technology (GRAID) that has been developed in the United Kingdom."

16.3 Please provide the analysis undertaken (both qualitative and quantitative), if any, on the selection of this new technology (GRAID) for the pipework inspection, including any alternative considered.

Response:

Currently, the only other option available for doing direct assessment on station pipework is to excavate down on the pipework, remove the wrapping and conduct Non-Destructive Testing on the pipework. It is worth noting that a section of the pipework that needs to be inspected is underneath a jointly-owned building and is surrounded by pipework also operated by Enbridge. To do the necessary inspections using traditional methods, PNG estimates the cost of the work to be in the order of $500,000, factoring in all the necessary engineering and resources that would be required.

The GRAID project is leading edge technology and will utilise robotics to conduct the necessary inspections on unpiggable station pipework while it remains in service.

16.4 Please clarify what portion of the total forecasted Compressor operating costs for Test Year 2021 is made up by this robotic inspection project.

Response:

The robotic inspection project is estimated at $78,000 of a consolidated budget of $798,000.

17.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.5, pp. 40-41
Account 685 - New Staff Positions

On page 40 of the Amended Application PNG states:

> Test Year 2020 expenditures of $3.229 million are forecast to increase by approximately $212,000 or 7.0% over Decision 2019 expenditure of $3.017 million. …. These cost increases have been offset in part by the absence of costs related to the implementation of the digital data mapping and the geographical information system projects that were incurred in 2019.
>
> …
>
> …the primary factor contributing to this increase is the full-year impact of the new management and field staff positions added in 2020, a further two new field staff positions and to inflationary pressures on other costs.

Further, on page 40 PNG states:

> Test Year 2021 expenditures of $3.513 million are forecast to increase by approximately $284,000 or 8.8% over Test Year 2020. As described below, the primary factor contributing to this increase is the full-year impact of the new management and field staff positions added in 2020, a further two new field staff positions and to inflationary pressures on other costs. [*Emphasis Added*]

17.1 For each management new position, please provide the actual/expected start date, annual salary and the forecast cost for 2020 and 2021.

Response:

PNG considers compensation information for individual positions to be confidential and has provided the information requested in this question with the responses to BCUC Confidential IR No. 1.

17.2 Please explain if the forecast costs associated with the new hires have been prorated to account for the expected start dates. If not, please explain why not and propose any adjustments to account for the expected start dates.

Response:

All costs associated with the new hires have been prorated for Test Year 2020 based on the expected start dates.

17.3 Please confirm, or explain otherwise, that the new management positions are full-time.

Response:

Confirmed. The new management positions are full-time positions.

17.4 Please provide the amount of digital data mapping and GIS project costs included in Decision 2019 and confirm, or explain otherwise, that these costs are not included in Test Year 2020.

Response:

For Decision 2019, included in Operating costs were $104,000 for Digital Data Maps and $200,000 for GIS Contractor Costs. As noted in the response to Question 75.1, the $200,000 included for GIS Contractor Costs was not incurred. PNG confirms that these costs are not included in Test Year 2020.

And on page 41, PNG states that "as it pertains to the four additional [field staff] positions PNG will directionally decrease its reliance on temporary employees, summer students, and contractors." [*Emphasis Added*]

17.5 Please discuss how PNG will reduce its reliance on temporary employees, summer students, and contractors and quantify the cost savings associated with this by account for Test Year 2020 and 2021.

Response:

PNG must continue to address heightened pipeline integrity programs, which benefits from internal resources with institutional company knowledge and training. With these added resources, PNG will have trained, dedicated employees with a knowledge of all relevant regulations, policies and procedures available to complete critical work necessary to maintain safe and reliable service.

PNG hires temporary employees and students to help with peaks in predictable workloads and vacation coverage during summer months. PNG reviewed the predictable workloads and determined that by hiring full-time employees, it would be able to utilize the employees year round and reduce the need for temporary employees and students. With the reduction of summer students, PNG is also reducing the risks associated with young and inexperienced workers from a safety and WorkSafeBC perspective.

PNG further notes that the hiring of these additional full-time employees will address significant demographic and work force challenges, as these employees are part of overall succession planning. PNG currently has a number of employees in the Construction and Maintenance department that are able to retire with unreduced pensions at any time. By hiring these full-time employees now, PNG can ensure continuity and that there is a transfer of knowledge.

In terms of cost savings, PNG has removed six summers students from its budget, saving $100,000 in operating costs. By reducing reliance on temporary employees, PNG will save another $264,000 (between capital and O&M). The FTE cost for the four field staff is estimated to be $412,000.

PNG hires contractors to perform work that is not part of the predictable base workload. To mitigate the cost impact of these positions, PNG plans to reduce the reliance on contractors. However, PNG does not believe there are significant savings as the impact of this is a reallocation of costs from contractors working on discrete projects to employees.

18.0 Reference: OPERATING EXPENSES
Exhibit B-2, Section 2.3.7, pp. 44, 90–91, 102, 111, Table 35; Tab 1, p. 3; Section 2.13.1.1.1, p. 102; Section 2.13.1.1.2, p. 111
Account 711/713/714 – New CIS System

On page 44 of the Amended Application, PNG states that it "…along with its sister utilities, AUI and HGL, have commenced a project to jointly implement a new CIS system to replace the existing legacy systems at the respective utilities."

18.1 Please discuss the alternatives to the implementation of the new CIS system that were considered, the pros and cons of the alternatives, and why they were ultimately rejected.

Response:

PNG considered the following alternatives to the joint implementation of the new CIS system with its sister utilities:

1. Maintain the Status Quo – rejected alternative

   Given the familiarity with the existing Banner system, PNG considered retaining the system with the current outsourcer but immediately rejected this alternative as the 20 plus year old technology had limitations on customer experience as well as the expectation that enhancements would no longer be supported by the outsourcer as addressed in the response to Question 18.2.

2. Stand Alone CIS System – rejected alternative

   With the need for a new CIS system, PNG and its sister utilities also engaged AAC Utility Partners, LLC (AAC), a CIS consulting firm specializing in utilities, to provide an estimate of a stand alone Tier 2 CIS system for each individual utility based on their experience. Using this information, PNG's analysis indicated that on net present value basis, a stand alone system would be $3.5 million higher than if PNG participated in a joint CIS system with its sister utilities. Based on this analysis and the knowledge that PNG's limited resources would make it difficult to manage the implementation of a new CIS on its own, the stand alone CIS system alternative was also rejected.

3. Joint CIS System Project with Sister Utilities – selected solution

   When the TriSummit Utilities Inc. (TSU, formerly ACI) utilities determined that a joint CIS system was the best solution, it engaged AAC to assist them with the preparation of the RFP as well as the selection of the CIS system and subsequent implementation of the system. During this process, a large number of vendors responded to the RFP of which five vendors were further evaluated, and eventually three vendors were shortlisted as the finalists. Two of the vendors were Tier Two category and one vendor was a Tier One category. PNG notes that all vendors were subjected to rigorous in depth demonstration presentations, interviews, and a scoring and evaluation process by all the core team members from the three sister utilities.

Based on this process, the utilities selected the best solution for the three utilities taking into consideration functionality, technology, implementation risk and costs. The conclusion was that the Tier One vendor VertexOne with its SAP product was the best alternative, based on the following:

- VertexOne will provide integration and hosting services for a pre-configured SAP solution marketed to mid-sized companies
- Hosted solution provided, therefore, all hardware and technical software will be managed by VertexOne
- Lowest cost on an NPV basis
- Internal staffing efficiencies to be realized from the hosted solution
- Shorter implementation timeframe and lower resource demands on implementation
- Superior and proven functionality and technology for utilities

18.2 Please elaborate on why PNG is reliant on UnionGas using the Banner CIS system and discuss any risks or issues associated with maintaining PNG's existing CIS system.

Response:

PNG has been utilizing the legacy Banner CIS system that has been operated and hosted by Vertex Data, L.P. since it was implemented in 1998 by an affiliated company (Enlogix) of the former Westcoast Energy Inc. for all its utility subsidiaries which included PNG, Union Gas, and the Centra Gas companies.

Over the years, Vertex provided the CIS services to these utilities and secured other third-party customers for the Banner CIS system. While the Centra companies were subsequently sold and migrated to other billings systems, Union Gas, the largest utility with approximately 1.5 million customers, remained the anchor customer using the Banner CIS, and Vertex continued to operate, host and provide software upgrades and support for all Banner CIS users, including PNG.

With the merger of Enbridge and Spectra in 2017 and subsequent amalgamation of Union Gas and Enbridge Gas Distribution to form Enbridge Gas in 2019, PNG became aware of Union Gas' plans to migrate to the SAP billings system utilized by Enbridge Gas Distribution. With the knowledge of the loss of the anchor customer for Banner, PNG deduced that the Banner system would not be supported by Vertex in the future. Discussions with Vertex personnel confirmed that resources and systems upgrades to Banner would be very limited after the migration of Union to its new system. Vertex also indicated that customers using the Banner CIS system would likely migrate to other CIS systems. Therefore, PNG believes that maintaining the existing CIS system would soon result in the potential loss of support from Vertex and PNG would be required to look for another alternative to manage its customer billing function.

Further, on page 44 PNG states:

> The joint CIS project will be led by AUI with significant involvement from PNG and HGL. Shared implementation costs will be capitalized by AUI and amortized over the expected useful life of 10 years. AUI will allocate and recover the capital costs from PNG and HGL on a cost-recovery basis under the terms of Shared Services Agreements that will be effective at the system go-live date expected in April 2021. AUI will also allocate shared support costs which includes the monthly fee to VertexOne for the managed services to be provided. The allocation is based on customer count, therefore PNG will be allocated approximately 31% of the costs.
>
> PNG will also incur direct capital costs for SAP licenses and data extraction from Banner to VertexOne.

On page 102 of the Amended Application, PNG states that "[i]n 2020, PNG-West anticipates incurring $108,000 for the extraction of data from the old Banner system as well as CIS license fees for the VertexOne CIS system that will be capitalized."

On page 111 PNG states that "[i]n 2021, PNG-West anticipates incurring CIS software costs of $98,000 for the VertexOne CIS system for data extraction as well as license fees."

18.3 For the new CIS system, please provide a breakdown of the total costs, costs allocated to PNG (consolidated) and costs allocated to PNG-West, PNG(NE) FSJ/DC and PNG(TR) by year, by operating and capital costs and by account number.

Response:

The new CIS system costs are composed of the following:

1. BCUC 713 - Shared Services Allocation for Implementation Costs – as noted in the Amended Application and the preamble above, the total shared implementation costs of $16.5 million will be capitalized by AUI and amortized over ten years and the related costs will be allocated to PNG on a cost recovery basis using customer count. For Test Year 2021, the total costs to AUI, HGL and PNG will be $1.74 million of which PNG will be allocated $0.51 million. PST will be required to be added to these shared services charges to PNG which will result in a total of $0.55 million and will be allocated to PNG-West and the PNG(NE) divisions based on customer count as noted in the table below:

			PNG Consol	[---------- Allocation	----------	]
Year	ACI Utilitites	PNG Consol	+PST	PNG West	FSJ/DC	TR
2021	1,738,999	510,785	546,540	267,313	263,269	15,959

2. BCUC 713 - Shared Allocation of CIS Support Costs – these include costs required to support the new CIS system and include the costs to operate the HelpDesk and other IT related costs. The total costs for Test Year 2021 are forecast to be $1.4 million of which PNG will be allocated $0.26 million based on customer count. PST will also be required to be added to this amount and result in total costs of $0.28 million to be allocated to PNG-West and the PNG(NE) divisions as follows:

			PNG Consol	[---------- Allocation	----------	]
Year	ACI Utilitites	PNG Consol	+PST	PNG West	FSJ/DC	TR
2021	1,430,865	257,613	275,646	134,818	132,778	8,049

3. BCUC 713 - Direct Operating Costs – this refers to the annual license maintenance fees to be paid by PNG forecast to be $20,415 for Test Year 2021 to be allocated to all the PNG divisions based on customer count and result in an allocation of $9,985 to PNG-West, $9,834 to PNG(NE) FSJ/DC and $596 to PNG(NE) TR division.

4. BCUC 487 - Direct Capital Costs – as noted in the Amended Application and the preamble, PNG will incur direct capital costs for SAP licenses and data extraction from Banner to VertexOne to be allocated to PNG-West and the PNG(NE) divisions as follows:

			PNG Consol	[---------- Allocation	----------	]
Year	ACI Utilitites	PNG Consol	+PST	PNG West	FSJ/DC	TR
2019		137,242	146,849	71,662	70,781	4,406
2020		207,494	222,019	108,345	107,013	6,661
2021		188,415	201,604	98,383	97,173	6,048

18.3.1 Please elaborate on why customer count was selected as the basis of allocating costs to PNG (consolidated) for the new CIS system identify any alternatives that were considered.

Response:

PNG submits that customer count is the most appropriate cost driver for the allocation of costs from the joint utilities to PNG Consolidated as well as from PNG Consolidated to PNG-West and to the PNG(NE) divisions based on the following:

- Provides a defensible cost causation linkage;
- Has a freedom from bias to favour one utility over the other;
- Is transparent, stable, accurate and sustainable; and
- Information on the driver is readily available.

Other alternative bases were not considered as customer count was determined to be the most appropriate and fair basis for allocation of the CIS costs.

18.3.2 Please provide the expected annual ongoing costs for the new CIS system.

Response:

As noted in response to Question 18.3, PNG will incur annual operating costs composed of the allocation of shared services for the implementation costs, the allocation of shared CIS support costs and direct operating costs for annual maintenance of the licenses for the CIS system. The table below provides a summary of the annual ongoing costs for the new CIS system for Test Year 2021 and the forecast for years 2022, 2023 and 2024. PNG notes that it will also incur depreciation and financing charges related to the direct capital costs incurred in years 2019 to 2021 as noted in response to Question 18.3.

BCUC 713		PNG Consol	[---------- Allocation	----------	]
	Year	+PST	PNG West	FSJ/DC	TR
CIS shared services charges and direct costs	2021	842,601	412,116	405,881	24,604
CIS shared services charges and direct costs	2022	1,360,450	665,396	655,329	39,725
CIS shared services charges and direct costs	2023	1,335,220	653,056	643,175	38,988
CIS shared services charges and direct costs	2024	1,310,401	640,917	631,220	38,264

18.4 Considering the system is expected to go live April 2021, please confirm or explain otherwise that there are no annual license fee costs allocated to PNG in Test Year 2020.

Response:

The annual license fee costs to PNG for Test Year 2020 have been categorized as development costs and have been included in capital for Test Year 2020.

On page 44 of the Amended Application PNG submits:

> As a corporate group, it was determined that implementation of a CIS solution that worked for all utilities would bring many advantages including sharing of common costs, more efficient use of resources, and the opportunity to merge and align business practices.

18.5 Please elaborate on how the new CIS system will allow the sharing of common costs, more efficient use of resources and the opportunity to align business practices. For each of these items, please provide the estimated annual costs savings and the timing of these benefits.

Response:

The joint CIS project allows for the sharing of common costs, a more efficient use of resources and the opportunity to align business practices as each of the three utilities will be required to utilize less internal resources on the project team compared to implementing a CIS system on a stand alone basis. PNG has dedicated approximately two full-time equivalent internal resources to this project and is reliant on some of the AUI team members to assist in certain areas during the planning and implementation phases of the project. AUI has dedicated approximately eight full-time equivalent resources and HGL has dedicated two full-time equivalent resources to the project. The use of common resources is reflected in the lower implementation and operating costs on the joint CIS project compared to a standalone CIS project. During the evaluation process, PNG determined that participating in the joint CIS project would result in total savings of approximately $3.5 million on a 10-year net present value basis compared to a stand alone CIS project.

With the joint project, the three utilities also harmonized the supplier for bill print and presentment and PNG expects to realize savings of approximately $100,000 on an annual basis and has reflected the proportionate 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. PNG expects that less internal resources will be required with the new system and plans to reduce the CIS technical support group by one headcount. PNG is also assessing redeploying the Customer Care resource to other work. The CIS technical support group headcount will coincide with the anticipated employee retirement.

18.5.1 Please discuss any other financial benefits PNG expects to realize from the new CIS system and the anticipated timing of these benefits.

Response:

Please see the response to Question 18.5.

On page 102 of the Amended Application PNG states:

> In 2020, PNG-West anticipates incurring $108,000 for the extraction of data from the old Banner system as well as CIS license fees for the VertexOne CIS system that will be capitalized.

On page 111, PNG states:

> In 2021, PNG-West anticipates incurring CIS software costs for $98,000 for the VertexOne CIS system for data extraction as well as license fees.

18.6 Please identify the relevant factors that should be considered from PNG's perspective in the treatment of data extraction costs for the purpose of capitalizing intangible assets in accordance with US GAAP.

Response:

PNG references US GAAP ASC 350-40, Internal-Use Software, to identify the relevant factors that should be considered in determining the treatment of data extraction costs. Specifically, ASC 350-40-25 indicates that there are three stages in the software development cycle:

- Preliminary project stage – involves planning activities prior to software development;
- Application development stage – involves activities to develop internal-use software; and
- Post-implementation operation stage – involves training and maintenance activities after the application has been developed.

The guidance states that costs incurred in the preliminary project and post-implementation operation stages are expensed, while costs incurred in the application development stage are capitalized with few exceptions. One of these exceptions is data conversion costs, defined in ASC 350-40-25-5 as "purging or cleansing of existing data, reconciliation or balancing of the old data and the data in the new system, creation of new or additional data, and conversion of old data to the new system."

PNG notes here that the data extraction costs referenced on pages 102 and 111 of the Amended Application are not the same as the data conversion costs described above. To clarify, the data extraction costs are paid to external consultants to develop scripts to extract, map, and load data and correct any loading problems. Therefore, these costs are incurred to ensure proper functionality of the software during the application development stage and not related to transferring data from the old system to the new. As such, PNG considers capitalization of the data costs to be consistent with US GAAP.

18.7 Please explain why data extraction costs are expected to be incurred in both Test Year 2020 and 2021.

Response:

Although the majority of the work related to the date extraction is expected to take place in Test Year 2020, PNG has negotiated the payment terms to take place over Test Year 2020 and Test Year 2021 and are reflected in the capital budget for these two years.

E. ADMINISTRATIVE & GENERAL EXPENSES

19.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5, pp. 49–50
Administrative & General Expenses

On page 49 of the Amended Application, PNG provides a breakdown of administrative and general expenses in Table 18 and states that "administrative and general expense line items have been presented net of shared service cost recoveries."

19.1 Please provide Table 18 revised to show the gross administrative and general expenses before the shared service cost recoveries from PNG(NE), including explanations for any significant variances that are not already provided in the Amended Application.

Response:

Please see Revised Table 18 below, showing gross costs before shared service cost recoveries from PNG(NE). The only two line items impacted by this change are BCUC Account 721 Administration and BCUC 728 General.

Revised Table 18: Forecast Operating Expenses (Gross)

	$000's											
BCUC Account	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
		$	%		$	%						
721 Administration	6,954	224	3.3%	6,730	1,243	22.7%	5,487	7,002	6,269	5,959	6,535	6,044
722 Special Services	982	19	2.0%	963	188	24.3%	774	791	864	778	708	472
723 Insurance	671	13	2.0%	658	176	36.5%	482	590	476	490	460	476
725 Employee Benefits	3,481	(64)	(1.8)%	3,545	(8)	(0.2)%	3,553	3,176	3,226	3,509	3,575	3,829
728 General	377	11	3.1%	365	90	32.6%	276	354	360	367	278	324
Sub-Total	**12,464**	**204**	**1.7%**	**12,261**	**1,689**	**16.0%**	**10,572**	**11,912**	**11,195**	**11,104**	**11,556**	**11,145**
Less: Transfers to Capital	(855)	(22)	2.6%	(833)	(439)	111.5%	(394)	(421)	(515)	(496)	(372)	(367)
Net Administrative and General Expenses	**11,609**	**182**	**1.6%**	**11,427**	**1,250**	**12.3%**	**10,178**	**11,492**	**10,680**	**10,608**	**11,183**	**10,778**

PNG has prepared the tables that follow to compare the variance between Decision 2019 and Test Year 2020 and between Test Year 2020 and Test Year 2021 for each of BCUC Account 721 Administration and BCUC 728 General, on a net basis as per the Amended Application and on a gross basis, as per the table above.

	$000's						
BCUC Account	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019
		$	%		$	%	
721 Administration	4,306	185	4.5%	4,121	572	16.1%	3,549
721 Administration - Gross	6,954	224	3.3%	6,730	1,243	22.7%	5,487

BCUC Account	$000's						
	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019
		$	%		$	%	
728 General	273	7	2.6%	266	70	35.4%	196
728 General - Gross	377	11	3.1%	365	90	32.6%	276

PNG observes that while the dollar and percentage changes on a gross basis differ from those computed on a net basis, the explanations for the variances remain consistent with those presented in the narrative provided in the Amended Application.

19.2 Please provide a breakdown of Account 721 – Administration costs presented in Table 18 for 2015, 2016, 2017, 2018 and 2019 actual and 2020 and 2021 forecast using the same categories as presented in Table 19.

Response:

PNG observes that Table 19 identifies specific cost items contributing to cost variances occurring between 2019 and 2020 and 2020 and 2021. The cost items noted are specific cost items and do not represent categories of costs included in Account 721 – Administration Expense. On this basis, PNG respectfully declines preparing the requested analysis.

20.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.1, pp. 51–53, Table 21
Account 721 – JDE Accounting System

On page 51 of the Amended Application, PNG states:

> Rather than opting to implement a standalone ERP for PNG alone, it was determined that it would be more cost-effective for all ACI entities to collaborate on a new ERP solution. This approach was considered to be prudent as it allows for cost savings at each of the entities as the result of sharing costs for servers, sustainment activities and IT support which would otherwise need to be incurred by each of the entities on a standalone basis. As all of the entities were already using various versions of JDE or related predecessor systems, it was decided to proceed with a JDE implementation. The decision was also made that the JDE system would be hosted at AUI in order to maximize economies of scale with existing AUI infrastructure and IT support personnel.

20.1 Please discuss the alternatives to the implementation of the new JDE system that were considered, the pros and cons of the alternatives, and why they were ultimately rejected.

Response:

The size and complexity of PNG, combined with the need for critical financial controls that were in AltaGas Ltd.'s (ALA) JDE system, immediately led to a determination that a similar ERP solution would be required to meet the needs of the company. PNG also quickly determined that a stand-alone ERP system would not be feasible due to the magnitude of the costs.

Following discussions with the other TriSummit Utilities Inc. (TSU, formerly ACI) entities, all of the companies agreed that a single ERP solution was required which would allow for all of the entities to benefit from cost savings as noted on page 51 of the Amended Application. PNG and TSU also negotiated for the transfer of critical coding from the ALA JDE system to the new JDE system that was relevant to PNG. This would greatly facilitate and expedite the implementation of the new joint JDE system.

The TSU entities briefly considered the SAP financial system as an alternative ERP solution to JDE, but there were significant disadvantages with using SAP as an alternative. These disadvantages included significant changes to the hardware architecture, implementation of a completely new system that none of the entities had experience with, and significant additional requirements for data conversion, training and increased resources to sustain the operations of the new system.

For PNG, the JDE alternative offered the advantage of minimal business disruptions, as it would allow PNG to maintain the functionality and processes developed and being used with its existing version of JDE as hosted by ALA. These benefits would not have been realized under an SAP alternative.

Given the familiarity with the JDE and the lower costs of implementing this system along with its sister utilities, PNG determined that the implementation of the new JDE system was the best solution.

20.2 Please provide the expected benefits and cost savings PNG will realize as a result of this new JDE system. Please quantify the annual cost savings by category and identify the year in which these savings will be realized.

Response:

By collaborating with the other TriSummit Utilities Inc. (TSU, formerly ACI) entities on a new ERP solution, rather than procuring a separate solution on a stand-alone basis, PNG is able to benefit from shared cost savings amongst the participating entities as the project costs would be allocated using a primary driver based on proportionate JDE license count. This includes certain common costs such as server and sustainment costs benefiting all entities, and results in PNG paying as little as 34% of the costs it would otherwise incur on a stand-alone basis.

In addition, there are qualitative benefits associated with the enhancements planned for Phase Three of the project which includes the implementation of a paperless invoice approval process and the return to a standardized chart of accounts that is consistent with BCUC codes. This will allow PNG to enhance its payable and payments processes and significantly reduce the amount of manual rework required for coding errors on invoices and expense reports. While this may not result in annual cost savings, these efficiencies will allow PNG's existing administrative staff to better support operational activities. Operational benefits will be further realized with the integration of other new systems, such as the new CIS and Maximo systems.

As noted in the Amended Application, with the formation of TSU as a standalone public company, PNG lost access to the ALA JDE system and determined the need for an alternative financial system. With the new joint JDE project with its sister utilities, PNG expects to obtain more timely, accurate and comprehensive information from the new JDE system that will better assist field staff to manage their operations more efficiently. At the moment, PNG does not anticipate any annual cost savings associated with the new JDE system.

20.2.1 Please explain the methodology for allocating costs to PNG for the JDE accounting system.

Response:

As described in the Amended Application, the methodology for allocating costs to PNG for the JDE accounting system is based on the work involved in each of the three phases of the project and using the number of licenses as the basis of allocation. During the planning phase of the project, all of the entities determined the number of licenses that would be required. These licenses were purchased at the beginning of the project for two reasons: 1) TriSummit Utilities Inc. (TSU, formerly ACI) received volume discounts from Oracle/JDE by purchasing the licenses as a group; and 2) the licenses were required prior to implementation for the configuration, development and testing of the environment before the system could "go live".

The total costs were budgeted into the three phases of work and the number of licenses owned by each of the entities impacted by that phase of work formed the basis for the allocation for the costs for that phase. For example, Phase One of the project, the upgrade of JDE, was for the benefit of AUI and HGL only. Therefore, PNG, TSU and BMWP did not receive any project cost allocations for Phase One.

For Phase Two of the project, the migration of PNG, TSU and BMWP, the costs were completely allocated to PNG, TSU and BMWP, as AUI and HGL did not benefit from that phase of the work. Given the significant number of licenses (85) that PNG has compared to TSU and BMWP, PNG was allocated the majority of the Phase Two costs.

Phase Three of the project pertains to the standardized chart of accounts, paperless invoice, and expense management for all the participating entities as well as the provision of customized enhancements to AUI and HGL. On the standardized chart of accounts portion, paperless invoice, and expense management, all the entities will be allocated their share of costs based on the number of licenses. On the customized enhancements, only AUI and HGL will be allocated their share for this portion of Phase Three.

20.2.2 Please provide the expected start and completion date of each phase of the JDE accounting system project.

Response:

Phase One started in June 2018 and was completed in May 2019. Phase Two started in May 2019 and was completed at the end of February 2020. Phase Three started in March 2020 and is expected to be completed by the end of June 2021.

PNG apologizes for the confusion with the reference to Phase Four on line 26 of Page 52 of the Amended Application. That was an error in reference and should have been noted as Phase Three.

On page 52 of the Amended Application PNG states, "[t]he second phase involves the migration of PNG, ACI and BMWP code and data from ALA to AUI."

Further, on page 52 PNG states:

> The third phase of the project will involve converting all entity general ledgers to a standardized chart of accounts…PNG will share in the costs associated with converting the Chart of Accounts. This phase will also involve providing AUI and HGL with the customized enhancements that exist in JDE now that the migration of the code and data from AltaGas has been completed in February 2020. The expectation is that most of the costs for these activities will be borne by AUI and HGL.

20.3 Considering the activities taking place in the third phase, please confirm, or explain otherwise, that PNG will only share the costs associated with converting the Chart of Accounts.

Response:

Not confirmed. PNG will share in the costs incurred in the third phase that will benefit PNG, which includes the conversion of the Chart of Accounts, paperless invoice, and expense management. Please also see the responses to Questions 20.2.1 and 20.3.1.

20.3.1 If not confirmed, please provide a breakdown of the activities and the associated costs allocated to PNG.

Response:

The activities to be completed in Phase Three include, but are not limited to:

- Conversion of the Chart of Accounts currently used by PNG to a format compatible with BCUC reporting (applicable for all entities);
- Implementation of Paperless Invoice Approval, allowing for documents to be scanned at inception of the processing cycle to reduce and in many cases eliminate the need for paper processing and filing (applicable for all entities). In addition, it also utilizes the financial authority matrix in JDE for invoice approval eliminating the requirement to obtain manual signatures while decreasing the risk of controls deficiencies;
- Review of Expense Management process, including opportunities to streamline expense report entry and improve approval processes (applicable for all entities);
- Supply Chain Management - functionality to be added for AUI and HGL;
- Implementation of Financial Authority Matrix - functionality to be added for AUI and HGL; and
- Implementation of Fixed Asset and Job Costing module – functionality to be added for AUI and HGL.

As noted above, PNG will be allocated costs proportionate to the number of licenses owned (85) distributed over the number of licenses owned by each of the entities benefitting from that phase of the work. Amounts included in the Amended Application were based on estimated costs for that work, but will be revised as more specific cost estimates are developed.

Additionally, on page 52 of the Amended Application, PNG states:

> As the JDE system will be hosted by AUI, the majority of the system costs are being capitalized by AUI. Capital costs will be amortized by AUI over an expected useful life of 10 years. AUI will allocate and recover the capital costs from other entities on a cost-recovery basis under the terms of a Shared Services Agreement that will be effective at the system go-live date, which was completed on February 26, 2020. As described previously, capital costs for each of the three implementation phases are to be allocated to those entities benefiting from the work on that phase. On this basis, PNG is expected to be allocated the majority of the capital costs incurred for phase two and approximately 34% of the capital costs for phase four. Based on the foregoing, on a consolidated basis for PNG and PNG(NE), the charge from AUI for these costs capitalized by AUI is estimated to be $191,000 for Test Year 2020 (ten months) and $258,000 for Test Year 2021 (full year).

20.4 Please provide a copy of the Shared Services Agreement related to the JDE system.

Response:

The Shared Services Agreement related to the JDE system is still being reviewed. PNG will submit a copy of the agreement with the BCUC upon its execution.

20.5 Please explain why PNG is expected to be allocated most of the capital costs incurred for phase two.

Response:

Please see the response to Question 20.2.1.

20.6 Please explain how the 34 percent allocation of the phase four capital costs was derived and why the allocation method is considered reasonable.

Response:

PNG apologizes for the incorrect reference to Phase Four as the project only consists of three phases. That was an error in reference and should have been noted as Phase Three.

As described on Page 53 of the Amended Application, the 34% allocation was based on the number of licenses owned by PNG as a proportion of the total number of licenses held by all of the TriSummit Utilities Inc. (TSU, formerly ACI) entities on the JDE system. The actual allocation will be based on the final costs incurred on the different projects undertaken in Phase 3 and the entities that will benefit from the implementation of those projects. The allocation method is considered reasonable as there are no other methods (e.g. number of transactions, number of journal entries, number of expense reports) that provide a better framework for allocating costs.

20.6.1 Given that the JDE implementation consists of three phases, please clarify what costs and activities are involved with phase four.

Response:

PNG apologizes for the incorrect reference to Phase Four as the project only consists of three phases. That was an error in reference and should have been noted as Phase Three.

On page 52 of the Amended Application, PNG states "[i]n 2019, [it] incurred a cost of $530,000 for these licenses which has been capitalized and reflected in work in progress at the end of 2019."

BCUC staff prepared the following extract of Table 21 on page 53 of the Amended Application, showing the allocation of the JDE licenses cost between PNG's divisions.

Table 21: Summary of Consolidated JDE System Costs

Expense Item	BCUC Account	Test Year 2020			
		PNG-West	FSJ/DC	TR	Total
JDE Licenses Capitalized	490	333,700	184,600	11,700	530,000

20.7 Considering AltaGas Ltd. is providing services through to June 30, 2020, please explain why JDE licences costs were incurred in 2019.

Response:

PNG incurred JDE licence costs in 2019 because those new licenses were required in order to configure, develop and test the system prior to the implementation. For PNG, the JDE system "go live" date was February 26, 2020, at which point the JDE support provided by AltaGas Ltd. was terminated. The licenses were also purchased early in order to take advantage of volume discounts available upon purchasing licenses for all of the TriSummit Utilities Inc. (TSU, formerly ACI) entities at the same time.

21.0 Reference: ADMINISTRATIVE AND GENERAL EXPENSES
Exhibit B-2, Section 2.5.1, pp. 54, 50
Account 721 – New Payroll System

On page 54 of the Amended Application, PNG states:

> With the formation of ACI as a separate standalone public company in October 2018, AltaGas entered into a Transition Services Agreement with ACI to remain as the provider of certain services up to a date no later than June 30, 2020. Those services included hosting the JDE payroll system on behalf of PNG. With access to AltaGas' JDE no longer being an option, PNG sought an alternative system that could process payroll.

Further on page 54 PNG states:

> Given all ACI-owned companies share similar human resource operational requirements and objectives, it was determined that a single Human Resource Information System (HRIS) would be the most cost-effective solution for all ACI entities. Based on responses to a call for proposals, UltiPro was selected as the best solution for the ACI group of companies from a cost, financial return, timing, IT, and strategy perspective.

PNG additionally states on page 54, that "[t]he UltiPro HRIS is being implemented in two phases: (i) the first phase" "occurred in February 2020; and (ii) the second phase, to proceed during 2020."

On page 54, PNG states:

> [t]he UltiPro third-party platform does not have any capital costs, but has a <u>monthly charge based on the number of employees and retirees</u> that are being served using the system. [*Emphasis Added*]

21.1 Please discuss the alternatives to the implementation of the new payroll system that were considered, the pros and cons of the alternatives, and why they were ultimately rejected.

Response:

As a result of the AltaGas Ltd. reorganization that saw PNG spun off with its sister utilities into TriSummit Utilities Inc. (TSU, formerly ACI), a new independent entity, PNG was required to identify a new payroll/HRIS system. As PNG's sister utility companies were all in a similar situation, a requirements analysis was undertaken in consultation with the other TSU entities. Three vendors were identified that could meet the identified requirements, including the vendor that PNG had used prior to the implementation of the JDE payroll module. PNG did not consider going on its own, as there were some implementation cost savings by partnering with the other TSU entities. These three parties were invited to respond to a request for proposals, with the responses providing a comparison of vendor costs for implementation, testing, and ongoing subscription fees.

All of the three vendors chosen to propose had the capability to provide the necessary requirements. One of the vendors was eliminated on the basis of cost, as their implementation were between 2 to 3 times higher than the other two proponents and annual employee subscription fees were approximately 1.5 times higher.

The other two vendors were asked to provide product demonstrations along with references, and were evaluated based on cost, system flexibility, user friendliness, and post-implementation support.

The vendor selected received the highest evaluation ratings in all areas, including cost, system flexibility and user friendliness, and based on references also had higher ratings for implementation experience and support after implementation. On this basis, Ultimate Software (UltiPro) was chosen.

21.1.1 Please elaborate on the reasons why UltiPro was considered the best solution for ACI from a cost, financial return, timing, IT, and strategy perspective.

Response:

Please see the response to Question 21.1. To reiterate, Ultimate Software was chosen as the best overall solution for the TriSummit Utilities Inc. (TSU, formerly ACI) group of companies based on the following three critical factors:

1) Cost competitiveness of both implementation costs and ongoing subscription costs;

2) User friendliness and flexibility as evidenced by demonstration and references for implementation experiences; and

3) Post-implementation support.

21.2 Please provide a breakdown of the total costs for the new payroll system, costs allocated to PNG and costs allocated to PNG-West, PNG(NE) FSJ/DC and PNG(NE) TR by phase, year and by account number.

Response:

As the new payroll system is a web-based platform, each entity has paid its own costs for the implementation of the system. PNG paid $72,000 in 2019 for implementation costs associated with Phase One. These costs were set up as a prepaid expense and are being amortized as an expense over an eight-year period. Additional costs of approximately $36,000 are expected to be paid in 2020 to implement Phase Two, and these costs will also be amortized over the remaining term of the licenses.

These costs, together with ongoing subscription costs for Test Years 2020 and 2021, are included in the Amended Application and allocated as follows:

	2020	2021
PNG-West	$ 57,000	$ 70,000
PNG(NE) FSJ/DC	18,000	19,000
PNG(NE) TR	1,000	1,000
Total	$ 76,000	$ 90,000

21.3 Please confirm that Test Year 2021 forecast costs include costs other than the monthly charges and explain the nature of the additional costs.

Response:

PNG confirms that the forecast for Test Year 2021 in the amount of $90,000 includes the amortization of costs to implement Phases 1 and 2 of UltiPro, in addition to monthly subscriptions.

21.3.1 If not confirmed, please explain why the increase from Test Year 2020 to 2021 appears greater than a full year of implementation costs plus inflationary cost increases.

Response:

Please see the response to Question 21.3.

21.4 Please confirm or explain otherwise, that all costs associated with this new payroll system are being allocated to PNG, among other "sister utilities", based on the number of employees and retirees in each entity.

Response:

Confirmed. All costs associated with the new payroll/HRIS system are allocated among 4 companies (PNG, AUI, HGL and TriSummit Utilities Inc. (TSU, formerly ACI)) based on the number of employees and retirees in each entity.

21.4.1 Please confirm, or explain otherwise, that only PNG, AUI and HGL will be implementing this new payroll system.

Response:

The new payroll system has been implemented by PNG, AUI, HGL and also by the parent company of these utilities, TriSummit Utilities Inc. (TSU, formerly ACI)).

21.5 Please discuss the expected benefits and cost savings to be realized from the new payroll system, including the anticipated timing of these benefits/cost savings. Please quantify any expected financial benefits by year. If no financial benefits are expected, please explain why.

Response:

As noted in response to Question 21.1, the need for a new payroll system was the result of the AltaGas Ltd. reorganization that saw PNG spun off along with its sister utilities into TriSummit Utilities Inc. (TSU, formerly ACI), a new independent entity. Given this corporate-wide need, the new payroll/HRIS system allows for alignment and consistency with the overall corporate strategy of the TSU group of companies.

By collaborating with the other TSU entities on the UltiPro system, PNG is able to benefit from shared cost savings in areas of implementation and testing.

Qualitative benefits are expected from system enhancements that will reduce the number of manual processes, making a number of them paperless. For example:

- Electronic timesheets will facilitate efficiencies in how labour is input into the system;
- Automation of coding for journal allocations will reduce errors and rework required with coding errors; and
- The recruiting module ensures that only qualified candidates are reviewed for open positions;
- The system provides storing and tracking of employee and Human Resource documents around training, performance management and more; and
- Documentation and the integration of benefits administration allows for changes to be made in real time with accurate tracking and less reliance on paper documents.

At this time, PNG does not anticipate any annual cost savings associated with the new HRIS system.

22.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.2, p. 56; PNG-West 2018-2019 RRA proceeding, Exhibit B-1-1 (Amended Application), p. 45;
Consulting Fees

22.1 Please prepare a table that includes the consulting fees by specific account (including 722, 721 and other accounts with consulting fees) for the following time periods: decision 2015, 2016, 2017, 2018, 2019, actual 2015, 2016, 2017, 2018, 2019 and forecast 2020 and 2021.

Response:

Please see the table that follows. Please note that the figures in the table include costs that are allocated to PNG(NE) through the shared services cost allocation:

($'s)	Test Year 2021	Test Year 2020	Actual 2019	Decision 2019	Actual 2018	Decision 2018	Actual 2017	Decision 2017	Actual 2016	Decision 2016	Actual 2015	Decision 2015
Account 721	1,016,000	923,000	408,000	403,000	340,000	373,000	282,003	457,000	620,773	448,000	484,389	379,140
Account 722	640,000	627,000	368,000	502,000	456,000	492,000	412,000	310,000	436,000	504,000	255,000	257,000

22.1.1 Based on the table prepared above, please provide an explanation for any significant variances between decision and actual for each year and significant changes in actual (or forecast for 2020 and 2021) amounts year over year.

Response:

Please note the following explanations for variances considered significant:

- 2015 – Unfavourable variance of $103,249, primarily due to additional finance contractors.
- 2016 – Unfavourable variance of $104,773, primarily due to additional finance contractors due to employee turnover.
- 2017 – Favourable variance of $72,997, primarily due to savings from IT contractors.
- 2018 – Favourable variance of $69,000, primarily due to savings from IT contractors.
- 2019 – Favourable variance of $129,000, primarily due to savings from IT contractors and a performance management system project which was cancelled with the decision to move to an HRIS system.
- 2020 – Increase of $774,000 over actual 2019, primarily due to inflation of 2%, JDE costs of $384,000 as noted on Page 53 of the Amended Application, incremental HRIS costs of $76,554 as noted on Page 58 of the Amended Application, and Microsoft MSDN subscription costs of $140,000. The increase in Account 722 is addressed in the response to Question 22.2, below.
- 2021 – Increase of $106,000 over Test Year 2020, primarily due to inflation of 2% and JDE and HRIS costs for a full year as noted on Pages 53 and 54 of the Amended Application.

On page 56 of the Amended Application, PNG states:

> **Consultant Fees (2020 increase: $124,000; 2021 increase: $13,000)**
>
> The increase in consulting fees for Test Year 2020 reflects an anticipated increase in consultation and engagement activity with government and industry on climate change policies and initiatives such as renewable natural gas (RNG) and the proposed federal clean fuel standards. The increase for Test Year 2021 is primarily due to inflation.

22.2 Please explain how the forecast 2020 and 2021 consulting fees for Account 722 were estimated.

Response:

The forecast 2020 and 2021 consulting fees for Account 722 were mostly inflated by 2% over the 2019 Decision amounts, with the exception of the Business Development consulting fees which were forecast at approximately $130,000 higher than the 2019 Decision amount.

The estimate for the additional Business Development fees was based on an evaluation of the assistance that PNG will require to develop the expertise to manage the future regulatory compliance requirements around the CleanBC plan. Please also see the response to Question 22.3.

On page 45 of the PNG-West 2018-2019 RRA Amended Application, PNG provided the following explanation for the increased costs in Business development and government relations consulting fees to $163,000 in Test Year 2018:

> Business development and government relations consulting fees for Test Year 2018 are forecast to be $21,000 greater than Decision 2017 in anticipation of increased consultation and engagement activity with government and industry on climate change policies and initiatives such as renewable natural gas (RNG) and the proposed federal clean fuel standards. [*Emphasis Added*]

22.3 Please discuss the benefits and cost savings that have been/will be obtained for each of PNG's ratepayers and its shareholder as a result of the work performed by consultants on business development and government relations. Please provide the actual/expected timing of these benefits and cost savings.

Response:

PNG is working with the BC Government and other stakeholders to identify and implement cost-effective and environmentally-responsible solutions for the reduction of greenhouse gas emissions. This includes PNG's participation in the funding of UBC's Natural Gas Futures Fund and the Canadian Gas Association's Natural Gas Innovation Fund, both of which are funding innovative technologies aimed at energy efficiency, emissions reductions, carbon capture and utilization and renewable natural gas (RNG) production and processing. In time, it is hoped that these technologies may be deployed within the PNG service area, enabling PNG to provide innovative solutions to our customers as well as to meet future regulatory compliance requirements.

In addition, in anticipation of the Clean BC 15% RNG mandate, PNG is looking for cost-competitive RNG and hydrogen supply opportunities, utilizing existing plus new innovative technologies, both within BC and elsewhere in North America. This will require innovative technical work in assessing the supply, understanding the contractual risks and managing the physical receipt and responsible use of RNG/hydrogen within the PNG system. PNG does not currently have the technical or contractual experience to effectively evaluate these opportunities and risks and therefore will employ consultants to assist in the immediate needs and help build longer-term internal experience.

PNG is currently engaged with both the BC Government and the Federal Government in discussions regarding the Low Carbon Fuel Standard (BC) and the Clean Fuel Standard (Federal), both impacting the future make-up of PNG's natural gas supply and/or emissions reductions requirements/options. Again, this is experience that PNG is building internally with the assistance of consultants.

PNG also continues to look at opportunities to service remote communities with natural gas via expansions of the existing pipeline network or via virtual pipelines. This work also utilizes the assistance of consultants to evaluate the availability and costs associated with potential supply options.

As the expertise needed for each of these endeavours can be very time sensitive, specific and narrow, adding to the PNG head count would be an inefficient way to manage these quickly evolving policy changes, compliance requirements and potential opportunities. PNG's ratepayers benefit from a more

cost effective, short term solution as a result of the work performed by consultants in these areas. PNG expects the timing of these benefits will be within the next few years as the emerging climate policies are enacted and with the approval of the BCUC, PNG begins to incorporate the various compliance mechanisms into its regular business.

22.4 Please identify any changes in circumstances in 2020 as compared to previous years in the areas of climate change policies and initiatives and the proposed federal clean fuel standards that contribute to the increase in consulting costs in 2020.

Response:

Please see the response to Question 22.3, above, particularly in the context of the anticipated 15% RNG mandate associated with the recently released CleanBC Plan.

22.5 Please discuss if PNG intends on using consultants for business development and government relations activities on an ongoing basis.

Response:

To the extent that PNG does not have the expertise in a particular area, PNG will continue to utilize consultants and subject matter experts on a measured basis.

22.6 Please identify and discuss any work associated with business development and government relations that is undertaken by PNG's parent company, ACI, and if this work has been factored into the shared services cost allocation to PNG.

Response:

Currently TriSummit Utilities Inc. (TSU, formerly ACI) does not carry out any work associated with business development and government relations on behalf of PNG. Therefore there are no business development or government relations costs factored into the shared services allocation to PNG.

23.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.1, p. 55
IT Contractors

On page 55 of the Amended Application, PNG states that "IT-related contractor costs have increased by $115,000 in Test Year 2020 from Decision 2019 as a result of PNG transitioning to the Microsoft 365 platform."

23.1 Please provide a timeline for the transition to the Microsoft 365 Platform, including when the transition is expected to commence and be completed.

Response:

Planning for transition to the Microsoft 365 Platform commenced in September 2019 and with its limited resources, the Company expects to complete this project in the third quarter of 2020. This includes upgrading all computers to the latest Office suite, moving e-mail services to the Cloud and utilizing Microsoft Teams for online collaboration. As part of the Microsoft 365 Platform, additional planning and resources will be required to implement SharePoint Online and is expected to be completed in 2021.

23.2 Please provide a schedule of historic and forecast costs broken down by year and between capital and operating costs for the transition to Microsoft 365 Platform.

Response:

There are no capital costs for the transition to the Microsoft 365 platform for the historic period nor Test Years 2020 and 2021. Operating costs associated with Microsoft 365 were approximately $7,000 for 2019 and estimated at approximately $85,000 for each of Test Years 2020 and 2021.

23.3 Please provide a description of the activities that will be undertaken by the contractor in 2021 in relation to the transition.

Response:

PNG notes that $78,000 of the $115,000 increase in IT contractor costs are for the annual subscription of the Microsoft 365 licenses. The remaining balance pertains to the contractor costs required to support the platform, backup the data as well as implementing additional security measures.

24.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.1, p. 55
Office Rent

24.1 Please provide the annual base rent for PNG's previous Vancouver office and the base rent for the new office space effective October 2019.

Response:

The annual base rent (including operating cost recoveries) for PNG's previous Vancouver office was $332,000, or $43 per square foot. The base rent for the new office space is $450,000, or $52 per square foot. As per the Amended Application, PNG reiterates that the base rent at PNG's previous office was heavily subsidized by its former parent company, AltaGas Ltd., during a time when competitive market rates for office space in downtown Vancouver for similar properties in 2019 ranged between $50 - $70 per square foot. PNG had negotiated very favourable terms with its former parent company for the use of the previous Vancouver office space.

On page 55 of the Amended Application, PNG states, "PNG incurred net costs of approximately $650,000 on tenant improvements to modify the leased space, inclusive of a tenant inducement allowance of $346,000. The costs incurred… are consistent with per square foot costs for tenant improvement projects."

24.2 Please describe the improvements that were required to the leased premises and discuss what tenant improvement projects were used for the comparison of the square foot costs for tenant improvement projects.

Response:

The leased premises required a major retrofit as the space had not been renovated in more than 10 years. Renovations included a significant HVAC upgrade, improved electrical and cabling, the creation of a secure server room, and the removal and reconstruction of most of the interior walls on the floor to create viable office and meeting room spaces. PNG was also able to reutilize almost all of the furniture that had been used in the previous office.

As per the response to Question 74.1, PNG referred to the Altus Group 2019 Canadian Cost Guide which is publicly available in establishing a budget for the tenant improvements required. Page 10 of the Guide specified a range of $100 to $190 per square foot for Interior Fitout for a Class A building. PNG initially assumed a budget of $150 per square foot to renovate the 8,657 square feet space, or $1.3 million. PNG was able to complete the tenant improvements for $115 per square foot which, after taking into account the tenant inducement allowance, was equivalent to $75 per square foot.

25.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.1, p. 55
Other Administrative Expenses

On page 55 of the Amended Application, PNG states:

> **Other Administrative Expenses (2020 increase: $143,000; 2021 decrease: $8,000)**
>
> The remaining cost change for Test Year 2020 and for Test Year 2021 reflect a variety of anticipated cost fluctuations in the normal course of business.

25.1 Please elaborate on the anticipated cost fluctuations that result in the forecast cost increase of $143,000 in 2020.

Response:

In preparing the response to this question, PNG noted an error in Table 19 appearing on page 50 of the Amended Application. The amounts presented for HR Contractors – HRIS and Vancouver office rent were incorrectly reported as net of amounts recovered from PNG(NE), and this carried through to the narrative on these two items. PNG apologizes for any inconvenience this error may have caused.

The correction of these items impacts the amount of $143,000 noted in the question for the 2019 to 2020 change – this amount is reduced to $93,000. A corrected Table 19 is as follows:

Expenditure Item	Cost Increase (Decrease) ($)	
	2020 to 2021 Change	2019 to 2020 Change
Shared Corporate Services Costs	37,000	1,092,000
Shared Corporate Services Costs - Shared Services Recovery from PNG(NE)	11,000	(401,000)
Shared Corporate Services Costs - PNG-West	48,000	691,000
Shared Corporate Services Costs - PNG-West Deferred	(25,000)	(675,000)
Shared Corporate Services Costs - PNG-West Cost of Service Impact	23,000	16,000
Finance Contractors - JDE	111,000	384,000
HR Contractors - HRIS	13,000	77,000
IT Contractors	7,000	115,000
Vancouver office rent	-	152,000
Other miscellaneous items	79,000	93,000
Offset by Shared Services G&A recoveries *	(48,000)	(265,000)
	185,000	572,000

* See Section 2.11 - Shared Services Recovery from PNG(NE)

The $93,000 is primarily due to:

- $50,100 increase in Data Line costs from the upgrading of internet capability at various offices to higher speed bandwidth to provide higher computer response times from servers; and
- $34,500 increase in travel costs for the Manager EH&S to reflect increased travel to field offices

25.2 Please provide a breakdown of the Test Year 2020 increase of $143,000 over Decision 2019 and actual 2019 costs and provide an explanation for any significant variances.

Response:

Please see the response to Question 25.1.

26.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.3, p. 57
Insurance

On page 57 of the Amended Application, PNG states, "The increase in forecast insurance costs for Test Year 2020 reflects a significant increase in property insurance premiums, which are approximately 14% higher over the prior year."

26.1 Please provide a breakdown of the actual 2019 and forecast 2020 and 2021 insurance costs, including a category for the property insurance premiums.

Response:

Please see the table that follows.

($'s)	Test Year 2021	Test Year 2020	Actual 2019
Property	589,000	577,000	496,000
Liability	82,000	81,000	96,000
Total	**671,000**	**658,000**	**592,000**

26.2 Please identify and discuss any increases in insurance costs that are related to the new ownership of PNG by ACI rather than AltaGas Ltd.

Response:

PNG did not incur any increases in insurance costs that are related to the new ownership of PNG by TriSummit Utilities Inc. (TSU, formerly ACI) rather than AltaGas Ltd. The insurance increases were related to increased property insurance and commercial general liability insurance premiums as well as PNG's recent insurance claim around the Copper River and Kleanza washout events as noted on Page 57 of the Amended Application.

27.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.4, pp. 61, 114
Employee Benefits

On page 61 of the Amended Application, PNG provided the following table summarizing the forecast and historic benefit load rates:

Table 25: Employee Benefit Load Rates

Employee Affiliation	Test Year 2021	2021/2020 Difference %	Test Year 2020	2020/2019 Difference %	Decision 2019	Decision 2018	Decision 2017	Decision 2016	Decision 2015
Executive	40.7%	(0.3)%	41.0%	7.0%	34.0%	33.9%	43.4%	41.4%	45.3%
Non-bargaining Unit	29.4%	(0.9)%	30.3%	(1.7)%	32.0%	33.1%	37.7%	36.9%	39.0%
Bargaining Unit - PNG-West	37.0%	(0.6)%	37.6%	1.5%	36.1%	37.6%	47.1%	47.9%	51.5%
Bargaining Unit - PNG(N.E.)	35.7%	(0.4)%	36.1%	(1.4)%	37.5%	38.7%	49.5%	48.0%	49.6%

Further on page 61, PNG states that "[t]he increase in Test Year 2020 rates is primarily due to increases in the actuarially determined pension costs on a 'per employee' basis, while the decrease for Test Year 2021 reflects generally lower pension costs for 2021 compared to 2020 for non-bargaining and bargaining unit employees. The Test Year 2020 benefit load rates are also impacted by the decrease in NPPRB costs compared to Decision 2019."

27.1 Please explain why pension costs are expected to be lower for non-bargaining unit employees in Test Year 2021 compared to Test Year 2020.

Response:

Under US GAAP, pension costs are determined using the following four components: service cost, interest cost on plan liabilities, expected return on plan assets (a credit), and the amortization of actuarial gains or losses. The Test Year 2021 pension costs are determined based on a projection of the plans' funded position at December 31, 2020 determined under US GAAP. This projection assumes that certain assumptions are borne out, and in particular, the assumption that plan assets will earn a return of 5.92% in 2020. These assumptions were set based on economic conditions as of January 2020.

Given this assumption, and the fact that PNG is remitting contributions to the Registered Plan on a monthly basis, the pension plans' overall financial position is expected to improve in 2020 which will result in a higher expected return on plan assets credit, as well as a lower amortization of actuarial losses in 2021. Under US GAAP, accrued actuarial losses in excess of the "corridor", which is determined as 10% of the greater of the plan's assets and liabilities, are amortized. As this "corridor" amount is expected to increase in 2020, it will result in a lower amortization cost to be recognized in 2021 and therefore pension costs are expected to be lower in Test Year 2021 compared to Test Year 2020.

On page 114 of the Amended Application, PNG state that "an actuarial valuation is planned as at December 31, 2019 and is anticipated to be completed in the third quarter of 2020."

27.2 Please provide a copy of this actuarial pension valuation report as at December 31, 2019 once it is made available.

Response:

PNG will submit a copy of the December 31, 2019 actuarial pension valuation at December 31, 2019 on a confidential basis when it is available late in the third quarter of 2020.

28.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.5, p. 61; Tab 1, p. 5
Account 728 – General

28.1 Please provide the Actual 2018 and 2019 Account 728 costs with the disallowed costs removed.

Response:

Please see the table that follows which provides a summary of costs included in BCUC Account 728 General. The table also reflects cost adjustments to reflect the disallowance of 50% of the Donations expense and the disallowance of 100% of the Stock Option Benefit Expense.

BCUC Account 728 General	**Actual 2019**	**Actual 2018**
Fiscal and corporate expense	15,627	49,000
Directors fees and expenses	-	-
Regulation	80,631	164,913
Donations	20,976	17,092
Less: 50% Donations	(10,488)	(8,546)
Corporate memberships	58,533	51,587
Other	42,251	(22,271)
Stock option benefit expense	57,275	23,129
Less: Stock option benefit expense	(57,275)	(23,129)
	207,530	**251,775**

29.0 Reference Administrative & General Expenses
Exhibit B-2, Section 2.5.1, p. 50, Table 20
Shared Corporate Services Costs

On page 50 of the Amended Application, PNG provides Table 20 illustrating ACI Shared Corporate Services Costs, an extract is presented below:

Table 20: ACI Shared Corporate Services Costs

	$000's										
Expense Item	Test Year 2021	2021 to 2020 Change $	2021 to 2020 Change %	Test Year 2020	2020 to 2019 Change $	2020 to 2019 Change %	Decision 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
Shared Corporate Services Costs	1,872	37	2.0%	1,835	676	58.4%	1,159	1,909	1,913	2,057	2,106
Disallowed by BCUC Decision	-	-	n/a	-	416	(100.0)%	(416)	(1,179)	(1,198)	(1,342)	(1,391)
Approved Recovery - Consolidated	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**730**	**715**	**715**	**715**
Applied for Recovery - per PNG	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**730**	**745**	**729**	**715**
Cost Allocation											
PNG-West	1,207	47	4.0%	1,160	693	148.1%	468	1,641	1,650	1,798	1,854
PNG(NE) - FSJ/DC	624	(10)	(1.6)%	634	375	144.8%	259	253	249	244	237
PNG(NE) - TR	42	0	1.0%	41	25	150.3%	16	16	14	15	15
Consolidated	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**1,909**	**1,913**	**2,057**	**2,106**

29.1 Please provide the 2019 actual Shared Corporate Services costs for Table 20. Provide explanations for any significant variances from the Decision 2019 costs.

Response:

Please see the table that follows that includes Actual 2019 Shared Corporate Services Costs.

	$000's											
Expense Item	Test Year 2021	2021 to 2020 Change $	2021 to 2020 Change %	Test Year 2020	2020 to 2019 Change $	2020 to 2019 Change %	Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
Shared Corporate Services Costs	1,872	37	2.0%	1,835	676	58.4%	1,159	1,777	1,909	1,913	2,057	2,106
Disallowed by BCUC Decision	-	-	n/a	-	416	(100.0)%	(416)	(1,034)	(1,179)	(1,198)	(1,342)	(1,391)
Approved Recovery - Consolidated	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**743**	**730**	**715**	**715**	**715**
Applied for Recovery - per PNG	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**743**	**730**	**745**	**729**	**715**
Cost Allocation												
PNG-West	1,209	48	4.1%	1,161	693	148.3%	468	1,501	1,641	1,650	1,798	1,854
PNG(NE) - FSJ/DC	622	(11)	(1.8)%	633	374	144.6%	259	259	253	249	244	237
PNG(NE) - TR	42	0	1.0%	41	25	150.3%	16	16	16	14	15	15
Consolidated	**1,872**	**37**	**2.0%**	**1,835**	**1,092**	**147.0%**	**743**	**1,777**	**1,909**	**1,913**	**2,057**	**2,106**

The Decision 2019 Shared Corporate Service costs of $1.159 million was established by PNG's former parent company, AltaGas Ltd. (ALA). This charge by ALA was estimated under the assumption that a large gas utility that ALA acquired in 2018, Washington Gas & Light, would have a significant impact on reducing the allocation to all its subsidiaries, including PNG, under the MMF formula. The actual Shared Corporate Services charges for 2019 of $1.777 million reflect the charges from TriSummit Utilities Inc. (TSU, formerly ACI).

29.2 Please explain whether ACI uses actual or forecast costs in the allocation of the Shared Corporate Service costs. If forecast costs, discuss how the risks of over/under forecasting are managed.

Response:

For annual budgeting purposes, TriSummit Utilities Inc. (TSU, formerly ACI) uses a forecast in the allocation of the Shared Corporate Services costs to its subsidiaries. For monthly financial reporting purposes (actuals), forecast costs are used for monthly accruals but a quarterly adjustment is made to true-up to actual costs incurred following the end of the quarter.

PNG notes that TSU has a robust budgeting process which uses several methods to forecast the Shared Corporate Services costs. Some costs (such as the annual DBRS fee and insurance costs) are known at the time of the annual budget cycle. For other costs, TSU reviews the prior year's actual costs incurred and makes adjustments based on any known business changes for the upcoming year. PNG submits that the forecast costs are a reasonable estimate for the actual Shared Corporate Services costs as the year end adjustment for 2019 was a recovery of $50,000, a 2.8% variance from the original forecast.

30.0 Reference Administrative & General Expenses
Exhibit B-2, Section 2.5.7.1, p. 63; Appendix B, pp. 2, 4-5
Shared Corporate Services Costs – Impact of Full Recovery

On page 63 of the Amended Application, PNG states:

> PNG deems it appropriate to seek full recovery at this time as in the first quarter of 2020, PNG will benefit from incremental near-term volumes associated with energy export related business activity in its service territory. Moreover, PNG expects to launch a successful reactivated capacity allocation process (RECAP) and utilize the available capacity that will result in significant benefits to ratepayers.

30.1 Please provide additional details on the incremental near-term volume referenced in the preamble, specifically the customer, forecast incremental volumes and margin and the test year in which the incremental volumes/margin will be realized.

Response:

The composition of the incremental volume and margin is provided in the table that follows.

	Test Year 2021		Test Year 2021	
	Deliveries GJ	Gross Margin $	Deliveries GJ	Gross Margin $
Kitimat LNG Project LDS#2	168,417	1,380,462	322,456	2,694,308
Kitimat LNG Project LDS#1	-	-	27,450	229,658
Watson Island Propane Export Project	7,820	64,465	31,025	260,859
Total	176,237	$ 1,444,926	380,931	$ 3,184,824

30.2 With reference to the expected timing for the realization of the incremental volumes resulting from the RECAP as provided in response to IR series 2 above, please elaborate on why PNG considers it appropriate to seek full recovery of the ACI Corporate Shared Services Charge in the current test period.

Response:

PNG benefits from the use of TriSummit Utilities Inc.'s (TSU, formerly ACI) shared corporate services. Previous to the formation of TSU, the Corporate Shared Services costs allocated to AltaGas Ltd. (ALA) subsidiaries were incurred to support a significantly larger operation that included utilities as well as large scale natural gas and renewable power generation assets, and midstream gas assets. TSU's Corporate Shared Service costs are specifically incurred to support its wholly owned utilities and are fair, reasonable and prudently incurred. This efficient structure is beneficial to PNG because it is able to share the costs associated with the necessary corporate services, without incurring the full standalone costs of those services on its own. PNG submits that its allocated amount is prudently incurred by TSU and necessary to PNG to conduct its business. As PNG should be allowed to recovery prudently incurred and necessary costs, now is an appropriate time to seek full recovery of these costs.

With respect to the RECAP and PNG's growth, PNG is also receiving benefits from the TSU Corporate Shared Services. For example, the capital required to support the RECAP project could be up to 50% of PNG's existing total rate base. PNG will rely on the Corporate Shared Services from TSU to provide sufficient capital and liquidity solutions for the project in order to minimize the access to capital risks for PNG and its customers. Given the RECAP will provide benefits to PNG's customers, the use of the TSU Corporate Shared Services is an efficient approach to support the funding of the RECAP.

For these reasons and those outlined in the rate application, PNG is seeking full recovery of the TSU Corporate Shared Services Charges in the current test period. That said, PNG continues to be cognizant of the effect that the recovery of any prudently incurred costs can have on customer rates. Therefore, PNG is proposing that a new interest bearing deferral account be established to record a large portion of the Shared Corporate Services Costs to be amortized at a future date instead of being recovered in the period the services are received by PNG.

30.3 Please identify and discuss any other factors and changes in circumstances, beyond utilization of the capacity on the PNG-West system, that were considered when deciding to seek full recovery of the ACI Corporate Shared Services Charge in the current Test Period.

Response:

As discussed in the Amended Application, TriSummit Utilities Inc.'s (TSU, formerly ACI) Corporate Shared Service costs are specifically incurred to support its wholly owned utilities and are fair, reasonable and prudently incurred. The allocated costs that are being incurred through the TSU Corporate Shared Service Charge benefit PNG's customers. The costs incurred at TSU allow PNG's customers to benefit from topics such as access to capital, sharing of expertise and best practices, while obtaining the benefits of economies of scale. This efficient structure is beneficial to PNG because it is able to share the costs associated with the necessary corporate services, without incurring the full standalone costs of those services on its own.

Prudently incurred and necessary costs should be fully recovered, which is why they are included in this Amended Application, however PNG is requesting a deferral account so they are not fully reflected in rates in the current test period.

Based on the estimates provided in the KPMG report, PNG will save approximately $2.236 million in 2020 and $2.281 million in 2021 in costs, compared to its costs had it been a standalone operation, because of TSU incurring certain corporate services costs on behalf of the whole group, and not only PNG.

31.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.7.1, p. 64
Shared Corporate Services Costs – Deferral Account

On page 64 of the Amended Application, PNG states:

> PNG is proposing that a new interest bearing deferral account be established to record a portion of the Shared Corporate Services Costs to be amortized at a future date instead of being recovered in the period the services are received by PNG. On a consolidated basis, the amount of the deferral included in PNG and PNG(NE)'s revenue requirements applications is $1.078 million for Test Year 2020 and $1.099 million for Test Year 2021. PNG will seek approval for the amortization of this deferral account in future years as PNG attaches more customer volumes in the system. Therefore, PNG is proposing to recover the amount approved under Decision 2019 plus an inflationary increase for both Test Year 2020 and Test Year 2021.

31.1 Please clarify if PNG is seeking to establish this deferral account and record a portion of Shared Corporate Services costs for the Test Period only, or if PNG plans to seek approval to record future costs beyond the test period in this deferral account as well.

Response:

PNG is seeking to establish this deferral account and record the portion of Shared Corporate Services costs that are not included in BCUC Account 721 and illustrated in Table 20 (page 50) of the Amended Application for Test Years 2020 and 2021. For Years 2022 and onwards, PNG expects to seek full recovery of the Shared Corporate Services costs under BCUC Account 721 in its cost of service.

31.2 Please provide an estimate for when PNG expects to commence amortization of the deferral account, with a rationale for the estimate provided, and the estimated amortization period.

Response:

PNG is hopeful that a successful RECAP will result in incremental large volume industrial transportation revenues and will enable PNG to seek amortization of the deferral account commencing in Year 2022. PNG cannot determine the estimated amortization period as this will be dependent on the outcome of the RECAP.

31.3 Please provide the incremental revenue deficiency/sufficiency and rate impact for Test Years 2020 and 2021 based the following scenarios:

(a) PNG is approved to recover the full amount, however not approved to defer any portion, of the ACI Shared Corporate Services Costs.
(b) PNG is approved to only recover a portion of the ACI shared corporate services costs that is consistent with decision 2019, and not approved to defer any portion.

Please provide all supporting calculations.

Response:

Scenario (a) - PNG is approved to recover the full amount of TriSummit Utilities Inc. (TSU, formerly ACI) Shared Corporate Services costs for each of Test Years 2020 and 2021 and does not defer any portion of these costs:

- The revenue deficiency for Test Year 2020 would increase by $676,000, which is equivalent to the amount of the deferral per the Amended Application. This would result in an increase in residential customer rates of approximately 2.0%. Therefore, for Test Year 2020, the revenue deficiency would be $1.45 million compared to $0.77 million and the residential rate increase would be 4.28% compared to 2.28%. Under this scenario, for Test Year 2021, there would be no change to the revenue deficiency of $0.8 million, as the incremental TSU Shared Corporate Service costs would be offset by the incremental margin from the higher rates established in 2020. Therefore, the Test Year 2021 residential rate increase would remain at 2.27% as the 2021 rate would already reflect the Test Year 2020 rate increase.

Scenario (b) - PNG is approved to recover a portion of the TSU Shared Corporate Services costs that is consistent with Decision 2019 and not approved to defer any portion:

- To be consistent with Decision 2019, PNG has made the assumption that the inflationary increase of 2% over the prior year's recovery for consolidated Shared Corporate Services costs would be approved and included in customer rates. Therefore, the revenue deficiencies for both Test Years 2020 and 2021 would remain exactly the same as in the Amended Application and the customer rate impacts would also remain the same as in the Amended Application. However, there would be no new Management Fee Deferral Account for either Test Year 2020 or Test Year 2021.

31.4 Under a scenario where the Shared Corporate Services costs deferral account is approved by the BCUC and the expected, incremental customer volumes on the PNG system do not materialize, please provide an estimate of the rate impact for PNG's existing customers based on an amortization period of one, three and five years.

Response:

Under the noted scenario, PNG provides the following table to illustrate, in a simplistic manner, the estimated rate impact for PNG's residential customers based on an amortization period of one, three and five years. PNG also notes that it has made the following base assumptions: 2021 deliveries and 2021 customer rates remain constant for the future years and, for illustrative purposes, interest on the deferral accounts are not included in the calculation.

		[----------		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%

31.5 Please discuss any issues associated with intergenerational inequity due to deferring Shared Corporate Services costs incurred in this Test Period to a future period.

Response:

PNG submits that the intergenerational inequity has been in place for the past years as PNG has not previously sought to recover the full amount of the Shared Corporate Services costs. However, as noted in previous applications, PNG continues to be very cognizant of the effect on customer rates of increasing the recovery of these charges and believes that with the expected successful outcome of the impending RECAP, it is now appropriate to seek approval of the full amount of the Shared Corporate Services costs through the deferral account proposal as set out in the Amended Application.

32.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.7.1, pp. 63-64; Appendix B, pp. 2, 4-5
Shared Corporate Services Costs – KPMG Report – Services and Allocation, p. 2 Methodology

On page 63 of the Amended Application, PNG states, "[t]he costs associated with the necessary services are incurred at the parent company level (ACI) and PNG is allocated its share of those costs."

On page 2 of the ACI Corporate Shared Services Cost Report (KPMG Report) filed as Appendix B, it states, "PNG represents approximately 19%, 21% and 31% of the property, EBITDA and payroll composite cost drivers of ACI respectively."

Pages 4 and 5 of Appendix B to the Amended Application, state:

> The costs related to the above noted Shared Corporate Services are combined into one common cost pool for allocation. The cost pool is then allocated to ACI's subsidiaries using the Modified Massachusetts Formula ("MMF"). The pool costs are actual costs, reflecting no mark-up, before being allocated to business units and subsidiaries.

32.1 Please discuss any differences between the current methodology for allocating Shared Corporate Services costs from ACI to PNG and the methodology used by PNG's former parent AltaGas Ltd.

Response:

To PNG's knowledge, there are no material differences between the current methodology utilized by TriSummit Utilities Inc. (TSU, formerly ACI) to allocate the costs associated with the Corporate Shared Services to PNG and the methodology used by PNG's former parent, AltaGas Ltd.

32.2 Please explain why EBITDA rather than revenues is used as one of the cost drivers for the MMF. Please provide the incremental increase/decrease of the shared services cost allocation over the Test Period if EBITDA was replaced with revenues as a cost driver.

Response:

EBITDA is used rather than revenues as a cost driver for the MMF as it is considered a better measure of a utility's output. Under the previous parent, AltaGas Ltd., an EBITDA cost driver was used as well.

Revenue includes the commodity cost of gas, which varies considerably across TriSummit Utilities Inc.'s (TSU, formerly ACI) three utilities. The cost of gas is a pass through cost so is not indicative of utility's output. Operating expenses are also a key component of utility output, which are included in EBITDA, but not in revenue.

For these reasons, the MMF allocation methodology uses EBITDA instead of revenue as a cost driver.

The PNG allocation factor using EBITDA as a cost driver is 24.7%, if revenue was used instead the allocation factor increases to 25.0%.

On page 4 of Appendix B, KPMG provides a summary of the services and benefits that PNG receives from the Shared Corporate Services received from ACI.

32.3 For each of the benefits listed, please indicate how this directly or indirectly benefits PNG's ratepayers.

Response:

Please see section 4.1 item 13 (page 4) of the KPMG report for a description of the benefits PNG receives from the Shared Corporate Services.

PNG's customers directly benefit from the Shared Corporate Services as PNG only incurs a portion of the costs for these services, instead of needing to cover the full amount of these costs if they had to perform all of these services as a standalone entity. Based on the estimates provided in the KPMG report, PNG will save approximately $2.236 million in 2020 and $2.281 million in 2021 in costs, compared to its costs had it been a standalone operation, because of TriSummit Utilities Inc. (TSU, formerly ACI) incurring certain corporate services costs on behalf of the whole group, and not only PNG.

On page 5 of Appendix B, KPMG states, "all the Shared Corporate Services outlined above will be performed by PNG if it was a stand-alone public company."

32.4 For each of the services that are being provided by ACI to PNG, please provide the cost of services from ACI, the previous cost of service from AltaGas Ltd. Please provide the costs PNG incurred in 2011, pre-AltaGas Ltd. amalgamation, adjusted for inflation.

Response:

Please see the table below for the previous 5 years of allocated shared costs from PNG's previous parent, AltaGas Ltd.

PNG's Shared Services Costs ($MM)	Average	2018	2017	2016	2015	2014
	$1.92	**$1.9**	**$1.9**	**$2.1**	**$2.1**	**$1.6**

Under TriSummit Utilities Inc. (TSU, formerly ACI), PNG was charged $1.8 million in 2019 by TSU for the Shared Corporate Services costs.

Please see the table on the page that follows for the PNG 2011 costs inflated and market adjusted as well as the 2020 TSU costs of service.

PNG's Corporate Shared Services costs	Estimated 2011 PNG fees (note 1)	Inflation factor (note 3)	PNG costs inflated	Remove costs included at PNG for 2020 (note 4)	2020 additional market adjusted costs (note 5)
Directors' fees and expenses	275,053	126.68%	348,429	-	**348,429**
Executive Management (note 2)	1,046,201	134.39%	1,406,007	(306,425)	**1,099,582**
Annual Report	45,839	117.17%	53,710	-	**53,710**
Shareholder expenses (Computershare, TSX, Broadridge, Bowne)	82,229	117.17%	96,348	-	**96,348**
Investor Relations	5,113	117.17%	5,991	-	**5,991**
Investor relations - printing	1,585	117.17%	1,857	-	**1,857**
Investor relations - accommodations	1,841	117.17%	2,157	-	**2,157**
Investor relations - meals & ent	1,841	117.17%	2,157	-	**2,157**
Investor relations - transportation	6,902	117.17%	8,087	-	**8,087**
Audit fees	247,552	117.17%	290,057	(180,000)	**110,057**
Internal audit fees	77,200	117.17%	90,455	(50,000)	**40,455**
DBRS fee	27,000	117.17%	31,636	(35,000)	**24,000**
Director's & Officer's insurance	63,500	117.17%	74,403	-	**211,985**
Fiduciary insurance	24,250	117.17%	28,414	-	**13,999**
Additional Liability Insurance ($150 MM coverage)					**238,206**
Crime insurance					**35,000**
Cyber insurance					**33,603**
Non-Owned aircraft insurance					**2,500**
Provincial registration fees					**37,304**
Translation fees					**84,183**
Legal fees	99,387	117.17%	116,452	-	**116,452**
Consultant fees	95,859	117.17%	112,318	-	**112,318**
Total	**2,101,352**		**2,668,476**	**(571,425)**	**2,678,379**
2020 PNG Shared Services cost allocation					**1,835,433**

Notes:

1) 2011 data based on 2012 Budget data included in 2012 RRA and 2011 actual fees incurred

2) Executive Management 2011 data for the President & CEO, VP Corporate Development & Treasurer, and VP Finance based on 2010 publicly disclosed compensation, therefore inflated 10 years
Includes all compensation except options and other compensation, consistent with ACI Executive Management compensation included in the Corporate Shared Services
As the VP Finance position still exists at PNG we have removed this inflated cost from the inflated 2020 costs

3) Inflation factor of 3% used on Directors Fees and Executive Salaries

4) Costs which were included in the 2020 budget for PNG have been removed to show only the incremental public company costs for 2020

5) Certain costs were not incurred at PNG in 2011 would need to be incurred in 2020 were PNG a standalone company. These costs have been included in this column. Also, inflated costs in 2011 which are market driven (specifically insurance) have been adjusted in this column to 2019 actual costs incurred at ACI

On page 64 of the Amended Application, PNG states:

> Through ACI's Shared Services model, these costs are allocated across ACI's three Utilities and renewable power assets, and PNG receives the full benefit of these key services at a lower cost than PNG could acquire them as a standalone entity.
>
> In order to validate the fair value of PNG's allocation of shared use of services and review the market value of those services, KPMG LLP has been engaged to produce a report to provide objective evidence for support of the validation of these costs (KPMG Report).

32.5 Please explain whether the ACI allocation methodology has been previously reviewed by any other energy regulator(s) in relation to the other utilities owned by ACI. If so, please provide relevant extracts from the regulatory Decisions.

Response:

The allocation methodology (the Modified Massachusetts Formula (MMF)) is a broadly accepted approach and has been reviewed by the Regulatory Commission of Alaska (RCA) as part of the revenue requirement application for ENSTAR Natural Gas Company in 2016 (Docket: U-16-066). PNG was a sister company to ENSTAR Natural Gas Company as both were owned by AltaGas Ltd. at that time. The AltaGas Ltd. allocated costs were not disputed and were approved in full by the RCA.

TriSummit Utilities Inc.'s (TSU, formerly ACI) two other utilities, AltaGas Utilities Inc. and Heritage Gas Limited have revenue requirements which include allocation of parent company costs which were last reviewed by their regulators in 2012 and 2011, respectively. However, in 2011 and 2012, those allocation methodologies had not yet incorporated the MMF.

33.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Appendix B, pp. 3, 11
Shared Corporate Services Costs – KPMG Report – Approach

On page 3 of Appendix B, KPMG describes the approach adopted in performing its assessment of the estimated fair value of Shared Corporate Services.

Page 11 of Appendix B states:

> KPMG has neither audited nor reviewed the underlying budgeted shared service cost pools, including the data that underpins the ACI's cost driver allocators that form the basis of their allocations nor has KPMG audited the estimate of fair value of shared services to be received from ACI.

33.1 Please explain why KPMG was not requested to complete an audit or review of the underlying budgeted shared service cost pools or the estimate of fair value of shared services to be received by ACI.

Response:

The budgeted shared service cost pools were developed and reviewed by TriSummit Utilities Inc. (TSU, formerly ACI) management and approved for inclusion in the Amended Application. The TSU Board of Directors also reviewed and approved the 2020 budget which included the shared service cost pools. TSU will be using actual costs incurred in the allocation of Shared Corporate Service costs in 2020/2021 and TSU's financial statements are audited by an external auditor.

KPMG was engaged to perform specified procedures in order to provide an independent assessment of the reasonableness of PNG management's estimate of the fair value of the shared services to be received from TSU. The specified procedures included comparison of the estimated costs from PNG to third party information, which can be analogized to audit level procedures. KPMG concluded that the methodology used by PNG management to estimate the fair value of the Shared Corporate Services to be received from TSU in 2020/2021 is an objective and rational methodology.

Also, as noted in the responses to Questions 32.1 and 32.2, there are no differences in the allocation methodology that was used by AltaGas Ltd. and that methodology was reviewed by KPMG in their report dated November 28, 2017, therefore was no need for KPMG to repeat the work for their recent engagement.

For these reasons KPMG was not requested to complete an audit or review of the shared service cost pools, as PNG will only be allocated shared service costs based on actual costs that TSU has incurred to provide the services and the allocation methodology was reviewed by KPMG for the 2017 report.

33.1.1 Please discuss the risks associated with using information that has not been audited nor reviewed.

Response:

As noted in the response to Question 33.1, the risk associated with using information that has not been audited or reviewed in this report is minimal, as costs are allocated to PNG based on actual costs incurred which are subject to external audit on an annual basis.

The scope of the review by KPMG was to ensure that PNG management's estimated costs had PNG been a standalone entity were reasonable, therefore, the procedures performed by KPMG, which included comparison to third-party information is sufficient. As indicated in KPMG's report, KPMG acted independently and objectively in preparing the report. The report was prepared in conformity with the Practice Standards of the Canadian Institute of Chartered Business Valuators.

34.0 Reference: ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Appendix B, pp. 5-10
Shared Corporate Services Costs – KPMG Report – Estimated Fair Value

On page 6 of Appendix B, the estimated fair value of the shared corporate services is provided in Table 2:

Table 2 - Estimated Fair Value of Shared Corporate Services

Shared Corporate Service Function	Standalone employee and third party costs 2020	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	1,835,433	1,872,142
Savings to PNG	**$ 2,235,671**	**$ 2,281,405**

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

34.1 For each Shared Corporate Service function, please provide the costs required in 2011, pre-AltaGas Ltd amalgamation. Adjust for inflation and compare to the 2020 KPMG Report estimate of the standalone employee and third party costs. Please provide discuss the reasons for any significant variances.

Response:

Please see the response to Question 32.4 for the 2011 PNG costs inflated and adjusted for market changes. The variances between the 2011 inflated and adjusted costs at PNG and the PNG estimate of the standalone costs in the KPMG report are mainly due to the salaries and benefits costs of the additional employees (General Counsel, two finance employees) that would be required to operate PNG as a standalone entity with substantial capital market access required for growth.

Further on page 6 of Appendix B it states:

> PNG Management assumes that as a standalone public company, it would have required the services of a seven member Board consisting of one executive and six non-executive members. PNG Management based the annual fees and retainers payable to the Board of Directors on the 'Corporate Board Governance and Director Compensation for Canada, Report for 2018' published by Korn Ferry (the "Korn Ferry Report").

Page 7 of Appendix B states:

> The Board size of 6 non-executive Board members and the fees and retainers payable to Board members are consistent with the average amounts paid to Board members of "micro companies", per the Korn Ferry Report, where no meeting fees are paid. Micro companies are the smallest company category identified in the report, and are defined as companies with assets of less than $1.5 billion, and would be the category PNG would fall into from a size perspective.

34.2 Please provide the total number of board members PNG required the services of in 2011, pre-AltaGas Ltd. amalgamation. If less than seven, please provide justification for the additional board members.

Response:

PNG confirms that in 2011, prior to the acquisition by AltaGas Ltd., it had six non-executive Board members and one executive Board member, for a total of seven Board members.

34.3 Please provide the average and median asset size of the "micro companies" per the Korn Report. Please compare to PNG's asset size to the median and average and discuss any differences.

Response:

The average and median assets size of the micro companies in the Korn Ferry report is approximately $800 million. The "micro companies" data set is the relevant size category for PNG, this is because while the average and medians are larger, the category includes a range of company sizes. For example, it includes smaller companies with assets of only $97 million, which is less than half of the PNG's asset base. The data set contains a range in this manner because the Board of Directors function and requirements are generally consistent across companies of various sizes within a range, and therefore compensation costs will be similar, even if the company is smaller than the average in the data set.

The TriSummit Utilities Inc. (TSU, formerly ACI) Corporate Shared Services model is more efficient for this reason. The full cost of the Board is incurred at the TSU level and then allocated across five assets, instead of each asset requiring its own standalone Board.

Further page 7 of Appendix B states:

> …to further assess the reasonableness of PNG Management's assumption to use the Korn Ferry Report, we also compared the annual fees and retainer amounts to amounts paid to ACI and FortisBC Energy Inc. ("FortisBC") Board members per their public filings. We consider the two companies to be comparable to PNG, being utility companies operating in Western Canada. Although the ACI and FortisBC amounts are lower than the Korn Ferry Report numbers, they are sufficiently approximate to suggest that it is reasonable for PNG Management to have used the Korn Ferry Report numbers as a reference point.

34.4 Please use specific metrics (i.e. asset size, revenues, etc.) to justify why ACI and FortisBC are considered comparable to PNG as a standalone entity.

Response:

Both TriSummit Utilities Inc. (TSU, formerly ACI) and FortisBC are larger than PNG in both assets and revenues, however they are considered comparable as they represent utility companies operating in Western Canada. Other Canadian utility companies that were evaluated as possible comparables for PNG standalone were substantially larger and were not considered appropriate to use for comparison purposes. Other utilities considered included Emera (approximately $13 billion market capitalization), Algonquin (approximately $10 billion market capitalization), and Canadian Utilities (approximately $9 billion), all of which are substantially larger than PNG standalone.

Although TSU is larger than PNG standalone it is the smallest public reporting utility in Canada, with a market cap of approximately $0.75 billion (prior to the announcement of its recent ownership change).

34.5 Considering both ACI and Fortis BC amounts are lower than the Korn Ferry Report number, please comment on the validity of using the Korn Ferry Report to base the annual fees and retainers for Board of Directors for a standalone PNG.

Response:

The Korn Ferry Report is the most appropriate source for the Board of Director annual fees and retainers as it takes in to account numerous data points for micro companies, whereas TriSummit Utilities Inc. (TSU, formerly ACI) and FortisBC are only single data points. As discussed in the response to Question 34.3, the duties and responsibilities of a Board are generally consistent across company sizes within the range, and therefore the compensation would also be consistent. For this reason, the Korn Ferry report with its multiple data points was considered the more appropriate source.

Page 8 of Appendix B states:

> We compared the CEO and CFO compensation payable to ACI's public filings and confirmed that the amounts used by PNG Management are consistent with the total direct compensation disclosed in ACI's filings. As a reasonableness check, we also compared the amounts to the compensation paid by FortisBC to its CEO and CFO per its public filings, and noted that the amounts are higher than that paid by FortisBC. We were also provided access by ACI to the '2019 CA Mercer Total Compensation Survey for the Energy Sector – General Benchmark' (the "Mercer Survey").

34.6 Please compare PNG's costs for the executive management positions in 2011, pre-AltaGas Ltd. amalgamation, to the costs of FortisBC executive management positions in 2011.

Response:

Please see the table below for the 2011 executive compensation. The compensation data provided excludes Stock Options and Other Compensation from both companies as stock options are not included in rates as per the BCUC and the EVP, Finance and Regulatory at FortisBC was terminated in 2011 and provided with a lump sum termination payment as Other Compensation. For consistency purposes Other Compensation has been excluded from both companies due to this lump sum payment at FortisBC.

2011 Executive Costs

	Total excluding Options & Other Compensation
FortisBC Energy (for 2011)	
President & CEO	1,027,157
VP, Finance and CFO/Treasurer	421,779
EVP, Finance and Regulatory	377,356
	1,826,292
PNG (for 2010)	
President & CEO	557,192
VP, Corp. Development & Treasurer	261,000
VP, Finance	228,009
	1,046,201

Note that PNG compensation is 2010 compensation data, public 2011 compensation data was not available for PNG.

34.6.1 Considering the compensation paid by FortisBC to its CEO and CFO are lower than that estimated for PNG as a standalone entity, please justify the additional costs.

Response:

The TriSummit Utilities Inc. (TSU, formerly ACI) compensation was used as a proxy for the PNG standalone estimate as it was the best comparable for PNG standalone as it is a small public utility company. As a reasonableness check on this assumption KPMG checked this data point against two other data points, FortisBC and the Mercer report. Upon reviewing these other data points KPMG validated that TSU was an appropriate data point for this estimate.

Pages 8 and 9 of Appendix B state:

> In estimating the fair value of PNG's hypothetical stand-alone accounting costs, PNG Management assumed that two additional accounting staff members would be required to fulfill all the additional accounting requirements of PNG, and that significant additional costs, such as higher insurance, additional credit rating costs and incremental audit and related fees would have to be incurred ("Net Additional Third Party Costs").

34.7 Please provide a breakdown of the 2011 and 2020 accounting, tax and finance stand alone costs.

Response:

Please see the table below for the 2011 and 2020 third party costs.

Salaries and benefits are not available for 2011, please see the response to Question 34.8.

Cost Description	2011 cost	2020 cost
DBRS fee	$27,000	$59,000
Insurance costs	$87,750	$542,500
Tax & accounting fees	$324,752	$373,908
Investor relations fees	$145,350	$51,996
Total Accounting, Tax & Finance	**$584,852**	**$1,027,404**

34.8 Please elaborate on the duties that would be completed by the two additional accounting staff members. Discuss whether these positions were staffed in 2011, pre-AltaGas Ltd. amalgamation, and whether there were subsequent cost reductions as a result.

Response:

As a stand-alone entity, PNG would require additional resources to perform the essential corporate services currently performed by TriSummit Utilities Inc. (TSU, formerly ACI) to maintain its public reporting issuer status for access to the debt and equity capital markets. Maintaining public reporting issuer status for access to capital markets requires considerable resources, including ensuring quarterly and annual securities compliance; ongoing communications with existing shareholders and prospective shareholders; communications with existing and prospective bond and debt investors; relationships with investment banking community to ensure adequate analyst coverage of company's securities; plus many other ancillary corporate functions and services. To satisfy securities disclosure requirements, quarterly and annual Management Discussion and Analysis and financial statements, Annual Information Form and Management Information Circular reports would need to be prepared and reviewed by securities/finance specialists and external counsel.

To accomplish these activities, PNG Management estimates that PNG would require two full time equivalent staff members (FTE) and would need to incur additional third party costs for external auditors, translation fees, tax consulting, additional insurance for Directors and Officers, Fiduciary, non-owned aircraft, and additional commercial general liability insurance, capital markets data access, transfer agent fees for public equity, and increased fees to maintain a public DBRS rating.

One additional accounting position was not staffed in 2011, however there was a Treasurer position in 2011 which is currently not staffed at PNG, treasury functions are currently provided by TSU through the Shared Corporate Services costs. The second additional accounting position would be required to complete the additional tasks listed above.

There were no cost reductions related to accounting and finance staff resulting from the AltaGas Ltd. amalgamation.

Page 9 of Appendix B states:

> PNG Management assumes that the services of a General Counsel would be required on a standalone basis, to provide PNG with the necessary legal advice, corporate governance and corporate secretarial services it would require. The General Counsel's role and seniority would be comparable to that of ACI's General Counsel.

34.9 Please explain whether PNG assumed the same level of services of a General Counsel in 2011, pre-AltaGas Ltd. amalgamation. If not, please discuss why it is required now.

Response:

PNG did not have a General Counsel in 2011 pre-AltaGas Ltd. amalgamation, but utilized the services of the Corporate Secretary employed by PNG and external legal counsel to assist with filing requirements.

A General Counsel is required as they are instrumental in accessing the capital markets to provide corporate funding, including ensuring compliance with all securities regulation, internal governance protocols for executing capital markets transactions and coordinating with external counsel to execute capital markets transactions.

As PNG was not in a growth phase in 2011 the need to access the capital markets was significantly lower, therefore there wasn't a need for a General Counsel. Now specifically due to the RECAP project, PNG is in a growth phase and needs significantly more capital markets access than it ever has before, therefore the services of a General Counsel to assist with securities registration compliance and accessing the capital markets are required.

Page 10 of Appendix B states:

> We compared and agreed the amount to the total direct compensation paid per the Mercer Survey for an executive level General Counsel. As a reasonableness check, we also compared the compensation to base salary amounts for a General Counsel per the Robert Half Survey, and noted that the base salary amounts used for the calculation fall within the 50th to 95th percentile range.

34.10 Please provide the median General Council salary per the Mercer Survey and Robert Half Survey.

Response:

PNG is not authorized to disclose specific Mercer salary data. KPMG was given permission to review the Mercer data used by PNG Management to estimate the fair value of the shared services to evaluate if the methodology used by PNG Management is fair and objective, but cannot disclose the specific data used. The data point used from the Mercer report was the mean, which is the 50th percentile.

The median General Counsel salary as per the Robert Half report is $175,750, however this does not include benefits or other compensation amounts, which would be required to engage a General Counsel for PNG.

34.10.1 Please compare the median General Council salaries in each of the surveys to that used in the KPMG Report, and comment on any differences.

Response:

Please see the response to Question 34.10.

35.0 Reference ADMINISTRATIVE & GENERAL EXPENSES
Exhibit B-2, Section 2.5.7.2, p. 66; Tab 1, p. 6
Non-Regulated Services to Affiliates

On page 66 of the Amended Application, PNG states:

> For Test Years 2020 and 2021, PNG has estimated that PNG's President would spend approximately 20% of her time fulfilling her obligations as an ACI executive, and that PNG's Director of Business Development would spend approximately 30% of his time fulfilling his obligations for BMWP. Based on these factors, PNG-West is reporting cost recoveries from the affiliates of $207,000 in Test Year 2020 and $212,000 in Test Year 2021 as a cost adjustment.

35.1 Please confirm whether the forecast cost recoveries in Test Year 2020 and 2021 are solely for non-regulated service (NRS) activities provided by PNG's President and Director of Business Development.

Response:

Confirmed. While there may be additional PNG employees that may provide non-regulated services to affiliates in the future, there are no amounts currently included in Test Year 2020 and 2021 for those possible cost recoveries. PNG would track any other employees who may provide non-regulated services and proposes to record their time in the Transfer Pricing deferral account if approved by the BCUC.

35.1.1 If not confirmed, please provide a breakdown of the PNG employees that performed NRS activities and the costs associated with each for 2020 and 2021.

Response:

Please see the response to Question 35.1.

35.2 Please explain how PNG ensures there is segregation of NRS activities from regulated activities thereby mitigating any risk of cross subsidization.

Response:

PNG's President and Director of Business Development are required to maintain timesheets to track hours spent between regulated and non-regulated activities. If additional employees are requested to be engaged in non-regulated activities, they are also required to maintain timesheets for the time spent on those activities.

35.3 Please discuss whether there are cost recoveries for the use of PNG resources, facilities, or general overhead as a result of the NRS activities. If so, please indicate where these cost recoveries are recorded in the financial schedules. If not, please explain why not.

Response:

PNG confirms that the cost recoveries included in the financial schedules include an hourly rate for the employees, as well as benefit loadings, general overhead and facilities costs. This methodology is in accordance with PNG's Transfer Pricing Policy recently approved under Order G-270-19.

Further on page 66 of the Amended Application, PNG states:

> PNG-West is proposing that the one-year interest bearing Transfer Pricing deferral account that was approved in the decision on the PNG-West 2012 Revenue Requirement Application (BCUC Order G-13-12) be reinstated and be used to capture differences between the forecast and the actual affiliate charges.

35.4 Please discuss the factors that contribute to forecast uncertainty for NRS activities. As part of the explanation, please comment on how forecasting NRS costs has changed as compared to the previous Test Period.

Response:

As noted in the Amended Application, the cost recovery forecasts included in Test Years 2020 and 2021 have been established based on the assumption that 20% of PNG's President's time and 30% of PNG's Director of Business Development's time will be spent on non-regulated activities. However, the actual amount of time spent on non-regulated activities will vary based on the requirements for the work performed, and therefore a variance between actual and forecast amounts will occur. PNG proposes that on a go-forward basis, any PNG staff working on NRS activities will track their time and any variances between actual and forecast time will be recorded in a deferral account.

PNG notes that in the previous Test Periods of 2018 and 2019, PNG had not contemplated any NRS activities. However, for the year 2019, both the President and the Director of Business Development did spend some time on NRS activities. PNG notes that both positions' labour costs were far greater than was embedded in the Test Year 2019 budgets; therefore PNG considers that time spent on these NRS activities were covered by the higher labour costs.

The Non-Regulated Business Recoveries account had been 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 providing any NRS to any affiliated companies. With the formation of TriSummit Utilities Inc. (TSU, formerly ACI) and the greater collaboration amongst the utilities, as well as the greater potential to explore non-regulated activities, PNG proposes that the proposed deferral account to track variances between forecast and actual time spent on NRS activities be reinstated commencing in Test Year 2020.

35.5 Please explain whether the deferral account will only capture the difference between forecast and actual cost recoveries for NRS activities for Test Year 2020.

Response:

PNG expects the deferral account to capture the differences between forecast and actual cost recoveries for NRS activities for Test Year 2020 and onwards. PNG is requesting a one-year amortization period. However, given that PNG has been filing two-year revenue requirements applications, PNG would seek immediate amortization in each revenue requirements.

35.5.1 If not, please discuss the estimated duration of the deferral account, and the amortization period.

Response:

Please see the response to Question 35.5.

35.6 Please provide the interest rate that will be applicable to the deferral account and the rationale for the rate proposed.

Response:

The interest rate to be used for the proposed reinstated one-year interest bearing Transfer Pricing deferral account would be the short term interest rate. This is the interest rate used for other short-term deferrals and is consistent with the rate methodology used for the previously used Transfer Pricing deferral account that was approved by BCUC Order G-13-12.

F. TRANSFERS TO CAPITAL (CAPITALIZED OVERHEAD)

36.0 Reference: TRANSFERS TO CAPITAL (CAPITALIZED OVERHEAD)
Exhibit B-2, Section 2.6, pp. 69-70, Table 27
Transfers to Capital

On page 69 of the Amended Application, PNG provides the following table that summarizes the capital overhead allocation, both historical and that forecast for Test Year 2020 and Test Year 2021:

Table 27: Transfers to Capital and Overhead Capitalization

	$000's											
Description	Test Year 2021	2021 to 2020 Change $	2021 to 2020 Change %	Test Year 2020	2020 to 2019 Change $	2020 to 2019 Change %	Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
Overhead Capitalization Rate [(A)/(B)]	**6.8%**	**0.2%**	**3.2%**	**6.6%**	**1.9%**	**40.3%**	**4.7%**	**4.7%**	**5.5%**	**4.7%**	**3.8%**	**3.7%**
Overhead as % of Capital Expenditures [(A)/(C)]	**10.1%**	**(0.6%)**	**(5.7%)**	**10.7%**	**(6.8%)**	**(39.0%)**	**17.6%**	**8.1%**	**5.9%**	**20.9%**	**15.9%**	**17.6%**
(A) Transfers to Capital												
Operating	699	42	6.4%	657	147	28.8%	510	510	543	397	362	314
Administrative & General	855	22	2.6%	833	439	111.5%	394	421	515	496	372	367
Total Transfers to Capital	**1,554**	**64**	**4.3%**	**1,490**	**586**	**64.9%**	**904**	**931**	**1,057**	**893**	**734**	**682**
(B) Expenses												
Operating	11,710	18	0.2%	11,692	2,139	22.4%	9,553	8,777	9,295	9,234	8,989	8,519
Maintenance	587	12	2.1%	575	70	13.9%	505	495	327	399	388	382
Administrative & General	8,858	138	1.6%	8,720	559	6.9%	8,161	9,475	8,717	8,576	9,242	8,929
Total Expenses - Net of Transfers to Capital	21,156	168	0.8%	20,987	2,768	15.2%	18,219	18,747	18,338	18,210	18,619	17,830
Plus: Transfers to Capital	1,554	64	4.3%	1,490	586	64.9%	904	931	1,057	893	734	682
Total Expenses - Gross	**22,710**	**232**	**1.0%**	**22,478**	**3,354**	**17.5%**	**19,123**	**19,678**	**19,396**	**19,103**	**19,353**	**18,511**
(C) Capital Expenditures (before Overhead)	**15,385**	**1,477**	**10.6%**	**13,908**	**8,762**	**170.2%**	**5,147**	**11,497**	**17,860**	**4,272**	**4,609**	**3,868**

36.1 Please confirm or explain otherwise that the 2019 actual overhead % as a percent of capital expenditures is lower than the decision 2019 % as a result of the increased actual capital expenditures as compared to decision.

Response:

Confirmed.

36.2 Please discuss if PNG conducts an assessment of the actual time spent and costs associated with corporate and management salary and benefits costs, support staff labour and benefit costs and field staff benefit costs, in order to assess the reasonableness of the overhead capitalization rate. If not, please explain why not. If yes, please provide the results of the analysis for 2018 and 2019.

Response:

As part PNG's preparation if its revenue requirements applications, it undertakes an assessment and evaluation of time and costs associated with salary and benefit costs capitalized.

As noted in Section 2.5.4.2 Employee Benefit Load Rates of the Amended Application, employee benefit costs are used to derive a benefit load rate to be applied to base labour costs in order to include an appropriate allocation of employee benefit costs to base labour costs included in shared service cost recoveries, transfers to capital and transfer pricing related to non-regulated activities. Benefit load rates are computed for each employee affiliation (i.e. executive, non-bargaining unit, bargaining unit) and are updated on an annual basis to reflect forecast benefit costs (i.e. pension, non-pension, extended health care, savings plans, etc.).

As noted in Section 2.6 Transfers to Capital (Capitalized Overhead) of the Amended Application, estimates are made of time spent in support of forecast capital activities for corporate, management and support staff (accounting and warehouse). Estimates of time spent in support of forecast capital activities are based on assessments made by key individuals directly supporting capital projects. For Test Year 2020 and Test Year 2021, the following assessments have been reflected in salary and wages capitalized:

Position	Time in Support of Capital
VP Operations & Engineering	41.5%
VP Regulatory & Gas Supply	5.0%
General Manager Operations	35.0%
Coordinator Lands & Permitting	57.5%
Manager Operations Accounting	25.0%
Manager Construction Maintenance	55.0%
Manager Technical Services	52.5%
Manager Engineering & Special Projects	60.0%
Project Engineer	80.0%
Project Engineer	80.0%
Integrity Engineer	20.0%
Field Staff - Operations Accounting	25.0%
Field Staff - Warehouse	50.0%

In addition, forecast direct capital labour costs for each division are used as a base to which the benefit load factors are applied. Forecast direct capital labour costs that attract a benefit loading are $1,372,000 for Test Year 2020 and $1,333,000 for Test Year 2021.

36.3 For Test Years 2020 and 2021, please separately show how much of the change in Operating Transfers to Capital and Administrative and General transfers to capital are related to: (i) changes to forecast capital expenditures; (ii) a change in allocation of corporate and management salaries and benefits to capital projects; (iii) a change in allocation of support staff salaries and benefits to capital projects; and (iv) a change in allocation of field staff benefit costs to capital projects.

Response:

Please see the table that follows.

Changes in Transfers to Capital

Factors Contributing to Change in Capitalization ($'s)	**Test Year 2021**	**Test Year 2020**
(i) Change in Proportion of Capital Expenditures	79,000	39,000
(ii) Change in Corporate/Field Management Allocation	19,000	158,000
(iii) Change in Support Staff Allocation	21,000	7,000
(iv) Change in Direct Capital Labour Benefit Load	(55,000)	382,000
Increase (Decrease) in Capitalization over Prior Period	64,000	586,000
Change in Transfers to Capital per Table 27	64,000	586,000
Difference	-	-

On page 70 of the Amended Application, PNG state that "[t]ransfers to capital for Test Year 2020 are forecast to increase in comparison to Decision 2019 primarily due to greater forecast capital expenditures, and due to an increase in direct capital labour over prior years as planned activities are to make greater use of PNG-West resources rather than contractors in 2020 and 2021."

36.4 With reference to the table on historic and forecast contractor costs provided in response to BCUC IR 36.1 above, please provide the amount of any corresponding decrease in contractor costs for 2020 and 2021 in relation to the plan to make greater use of PNG West resources.

Response:

PNG is unclear of the reference made to "the table on historic and forecast contractor costs provided in response to BCUC IR 36.1" in this question.

PNG provides the following information to illustrate the decrease in contractor costs as a percentage of total capital expenditures for Test Year 2020 and Test Year 2021 compared to Decision 2018 and Decision 2019. PNG further notes the overall increase in the magnitude of internal labour costs attributable to capital projects. While the mix of contractor costs to labour costs is dependent on the nature of a capital project, the data in this table illustrates higher forecast internal capital labour for Test Year 2020 and Test Year 2021, leading to an associated increase in capitalized benefit costs.

Review Period	Capital Expenditures	Contractor Costs		Internal Labour	
	$	$	% of CAPEX	$	% of CAPEX
Decision 2018	17,244,000	14,199,000	82%	844,000	5%
Decision 2019	5,147,000	3,162,000	61%	459,000	9%
Test Year 2020	13,908,000	7,581,000	55%	1,383,000	10%
Test Year 2021	15,385,000	8,103,000	53%	1,331,000	9%

G. PROPERTY TAXES

37.0 Reference: PROPERTY TAXES
Exhibit B-2, Section 2.7, p. 71
Property Taxes

On page 71 of the Amended Application, PNG provided the following table showing the forecast and historic property taxes:

Table 28: Property Taxes

	$000's											
Expense Item	Test Year 2021	2021 to 2020 Change		Test Year 2020	2020 to 2019 Change		Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
		$	%		$	%						
Property taxes	3,735	73	2.0%	3,662	156	4.5%	3,505	3,505	3,437	3,379	3,313	3,322
1% in lieu	385	-	0.0%	385	(36)	(8.5)%	421	421	349	371	371	349
Total	**4,120**	**73**	**1.8%**	**4,047**	**121**	**3.1%**	**3,926**	**3,926**	**3,786**	**3,751**	**3,684**	**3,670**

Further on page 71, PNG states that "[t]he forecast for Test Year 2020 property taxes is based on 2019 assessed values with an inflationary increase of 2%."

37.1 Please reconcile the inflationary increase of 2 percent in 2020 to the table in the preamble.

Response:

PNG notes that the actual cash amount of property taxes paid to municipalities in 2019 were $3,590,000, compared to the Decision 2019 amount of $3,505,000. PNG also notes that variances between the forecast and actual amount of property taxes are recorded in the property tax deferral account. Therefore, the recorded property taxes for Actual 2019 reflect the Decision 2019 amount. PNG apologizes for not making this clarification in the Amended Application narrative.

As such, the Test Year 2020 property taxes have been estimated by an incremental 2% from the 2019 actual cash amounts paid to municipalities. PNG considers this method to be the best estimate for the following year's property taxes.

H. DEFERRAL ACCOUNTS

38.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Section 2.9, pp. 74-75.
Amortization – Net Salvage and Removal

On page 74 of the Amended Application PNG states:

> PNG has forecast $305,000 of removal and retirement costs and has included this amount as a drawdown of this credit deferral account in Test Year 2020. The majority of these costs will be used to formally abandon the Rio Tinto Lateral Plant Site as no gas is expected to flow in this pipeline in the future.

On page 75 of the Amended Application PNG states, "has also forecast $34,000 of removal and retirement costs for series in Test Year 2021."

38.1 Please explain how the 2020 and 2021 forecast amounts are derived.

Response:

As noted, the majority of the costs pertain to formally abandoning the Rio Tinto Lateral Plant Site. Forecast project costs for removal and retirement are built using a Class 5 estimate based the assumption that the majority of the work could be performed in the 2020 test year.

	2020
Contractor	$255,000
Labour	10,234
Materials	510
Auto	1,530
	$267,274

The project scope involves in-service welding by a contractor on the current existing pipe in order to stop the flow. Then the current pressurized dead leg will be de-pressurized by flaring the gas. The location of this line is in a heavily industrialized location and in order to safely de-pressurize the line, it will require numerous safeguards. The line will then be abandoned in place per appropriate regulations.

The landowner is an industrial facility and may have additional requirements for abandonment above and beyond the normal methods and these costs are expected to trail into 2021. These costs are expected to be minimal in nature in comparison to the cost of executing the work proposed for 2020.

39.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Section 2.9, p. 75; Tab 2, pp. 19-20
Amortization – Demand Side Management

On page 75 of the Amended Application, PNG provides context on the Demand Side Management (DSM) deferral account.

On Tab 2, pages 19 and 20 PNG presents the continuity of deferred charges for the Test Year 2020 and 2021. Line 7 of each page is the DSM deferral account.

39.1 Please confirm or explain otherwise, that PNG defers all of its DSM expenditures to the DSM regulatory account.

Response:

PNG confirms that all DSM expenditures are deferred to the DSM regulatory account, other than salary and benefits costs of the Manager, Energy Solutions, who is responsible for program design and administration. These salary and benefits costs are accounted for as a general and administrative cost.

40.0 Reference Deferral Accounts
Exhibit B-2, Section 2.9, p. 78
PLP Project Amendment Sharing

On page 78 of the Amended Application PNG seeks approval for the dissolution of the PLP Project Amendment Sharing deferral account.

40.1 Please provide an update on the status of the PLP project and identify any forecast 2020 and 2021 costs associated with the PLP project.

Response:

PNG is currently monitoring opportunities for the PLP Project and only progressing project development at a gradual pace. PNG provides the following update with respect to project feasibility and permitting.

Project Feasibility

With a resurgence in LNG markets in the past 2 years, PNG made modest progress by actively advancing discussions with domestic and international customers interested in a pipeline expansion. PNG had some discussions on commercial arrangements with project proponents to serve several major industrial developments. At this time, these discussions have not resulted in any commercial contracts. For that reason, PNG's primary focus has been on the RECAP project to add additional industrial customers to its existing network, with some smaller scale expansions expected to benefit existing PNG customers in the near term.

With the PLP Project, PNG has undertaken some analysis on commercial and engineering approaches that could deliver the natural gas throughput more economically. The Company is aware of the sensitivity to pipelines in the region amongst Indigenous Nations and stakeholders. Thus, PNG has worked closely with Indigenous Nations over the past several years, seeking to provide meaningful community benefits from the project if it were to advance.

PNG believes that given its investment to date and its strategic position in the region, the PLP Project has the potential to provide significant benefit to the regions of northwestern British Columbia. These benefits could be realized from the expansion of PNG's unique position of offering natural gas transportation service to multiple industrial projects along British Columbia's west coast.

Permitting

The PLP Project entered the Environmental Assessment Certification (EAC) process in 2013. The majority of environmental, socio-economic and engineering studies to support the EAC Application for the project were completed by the end of 2015. However, due to deteriorating market conditions for natural gas at that time, work on the project and the EAC Application was paused. This work was backstopped and paid for by a major industrial customer.

In 2018, markets began to show signs of recovery and there was increased interest in demand on PNG's system. In 2019, PNG made some progress in the following areas:

- Conducted the Multi-Lateral Process (MLP) to confirm market demand for pipeline capacity; this work ultimately resulted in insufficient commercial interest for a major pipeline expansion, but enough commercial interest to actively proceed with the RECAP process;
- Engaged with Indigenous Nations and stakeholders along the pipeline corridor; and
- Undertook smaller field studies on caribou, fish and fish habitat to update baseline studies conducted in 2014 and 2015. PNG also advanced winter tracking studies. In all studies, PNG worked with local Indigenous Nations.

More recently, after discussions with the BC Environmental Assessment Office (BC EAO), PNG informed the BC EAO that it would like to transition to the new environmental assessment process under the BC *Environmental Impact Assessment Act 2018*. The Company recognizes that this will require additional field work, application process and engagement with Indigenous Nations. PNG would only proceed with such work if backstop arrangements were in place with major customers.

In recent weeks, communication networks and business processes have been severely affected by the COVID-19 pandemic. As a utility, PNG's primary focus has been, and will continue to be, on maintaining essential services to residential and commercial customers. Furthermore, Indigenous communities are also justifiably focusing their resources and attention on the health of their people and communities.

In summary, the PLP Project continues to be strategic opportunity for PNG, but it is moving at a very slow pace of development in order to retain the optionality for future growth. With respect to growth on its pipeline system, PNG's primary focus is RECAP at this time.

41.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Section 2.9, p. 78
Amortization – Resource Plans

On page 76 of the Amended Application PNG states:

> This deferral account records the variance between actual and forecast costs incurred in the preparation and review of PNG's resource plans. PNG-West and PNG(NE) filed the 2019 Consolidated Resource Plan in October 2019, and anticipate future submissions to be made every five years. There is no forecast amortization for Test Year 2020.

41.1 Considering the Consolidated Resource Plan was prepared and subsequently filed in October 2019, please explain why no additions were included for 2019.

Response:

The Consolidated Resource Plan was prepared almost entirely with internal resources and led by PNG's Manager, Energy Solutions, whose labour cost is embedded in the 2019 General and Administrative expenses. Therefore, there was no addition to the deferral account in 2019 as there was no variance between actual and forecast costs for its preparation.

42.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Section 1.3, p. 7; Section 2.9, p. 78
Amortization – Option Fee Payment

On page 78 of the Amended Application, PNG states:

> This interest bearing deferral account was initially established under Order G-174-08 to track the receipt of option fee payments received from customers to secure future transportation capacity in PNG-West's system.

42.1 Please confirm, or explain otherwise, that the LNG Partners Option Fee Payment deferral account does not include payments for active contracts whereby the option fees may be required to be credited back to the other party.

Response:

Confirmed.

Further on page 78 of the Amended Application, PNG states: "As at December 31, 2019, the credit balance of this account was $4.677 million. For Test Year 2020 and Test Year 2021, PNG-West is proposing to drawdown $0.857 million and $2.825 million respectively."

42.2 Please provide the rate impact for 2020 and 2021 in the absence of any amortization of the LNG Partners Option Fee Payment Deferral account.

Response:

In the absence of the proposed amortization of the LNG Partners Option Fee Payment Deferral account, the revenue deficiency for Test Year 2020 would be higher by approximately $0.857 million and would result in an additional residential delivery rate increase of 2.5%. For Test Year 2021, the revenue deficiency would be higher by approximately $1.94 million, reflecting the absence of the proposed 2021 amortization slightly offset by higher margins due to the 2020 rate change, and would result in an additional residential delivery rate increase of 5.2%.

43.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Tab 2, p. 19
Amortization – One Year Amortization Period

On page 19, Tab 2, PNG provides a continuity schedule of deferral charges for Test Year 2020. An extract of the schedule is provided below:

Line No.	Description	Interest Rate	Amortization Period	Actual Balance '19	Additions	Imputed Interest	Amortization	Test Year Balance '20
	...							
12	**NOT INCLUDED IN RATE BASE:**							
13	Pipeline Inspections	STI	1 yr	595	-	13	609	-
14	Line break costs	WACD	n/a	(134)	-	(2)	(188)	52
15	Investigative Digs	STI	1 yr	(470)	-	(11)	(481)	-
16	PLP Termination Cost of Service Credit	STI	1 yr	(0)	-	(0)	(0)	-
17	Rate Smoothing	STI	1 yr	-	-	-	-	-
18	RSAM	WACD	n/a	3,184	(2,492)	106	-	798
19	GCVA	WACD	n/a	289	(164)	16	-	141
20	Pension / NPPRB	WACD	3 yrs	(78)	-	(4)	(7)	(75)
21	Accelerated Capital Cost Allowance - 2019	STI	1 yr	(176)	-	(4)	(180)	0
22	Industrial Customer Deliveries	STI	1 yr	(1,308)	-	(30)	(1,337)	-
23	BCUC Fees	STI	1 yr	72	-	2	74	-
24	BCUC Proceedings	STI	1 yr	(35)	-	(1)	(36)	-
25	Property Tax Variance	STI	1 yr	(23)	-	(1)	(24)	-
26	Resource Plans	STI	1 yr	-	-	-	-	-
27	Short term interest	STI	1 yr	(12)	-	(0)	(12)	-
28	Long term interest	STI	1 yr	(114)	-	(3)	(116)	-
29	Old Revolving Debt Issue Costs	STI	1 yr	-	-	-	-	-
30	LNG Partners Option Fee Payment	STI	tbd	(4,677)	-	(194)	(857)	(4,014)
31	Management Fee Deferral	STI	tbd	-	676	13	-	689
32	Sub-Total: Gross Interest Bearing Deferrals			(2,887)	(1,980)	(99)	(2,557)	(2,409)

43.1 For any deferral accounts that capture forecast and actual variances from the prior Test Period (in this case 2018 and 2019), please discuss the pros and cons of a one-year amortization period as compared to a two-year amortization period.

Response:

PNG notes that the one-year amortization period for PNG's deferral accounts that capture forecast and actual variances are in compliance with the key principles for the treatment of deferral accounts established by the BCUC in the FortisBC Decision under Order G-110-12 and reiterated in PNG's 2013 Revenue Requirements Application Decision under Order G-114-13.

Changing to a two-year amortization period would enable rate smoothing, especially if the deferral account has a significant debit balance. However, a longer amortization period would likely result in increased costs due to the accumulation of financing charges at a higher rate as the appropriate return would be the utility's Weighted Average Cost of Debt instead of the short term debt rate.

43.1.1 Please provide the rate impact for 2020 and 2021 of applying a two-year amortization period to these deferral accounts.

Response:

The total amortization for the deferral accounts with a one-year amortization period for Test Year 2020 is a credit amount of $1.5 million. Therefore, applying a two-year amortization period for these deferral accounts implies that the amortization for Test Year 2020 for these accounts would be a credit of approximately $0.75 million and the amortization of Test Year 2021 would include a credit of the other $0.75 million (for illustrative purposes, not including the impact of interest). Given that these are credit amortizations, the revenue deficiency in Test Year 2020 will increase by approximately $0.75 million and result in a residential delivery rate increase of approximately 2.2%. There would be no further change to Test Year 2021 rates as the 2020 rate change would already reflect the additional $0.75 million credit amortization. Rates in 2022 would reflect the loss of the credit amortization from Test Year 2021.

44.0 Reference DEFERRAL ACCOUNTS
Exhibit B-2, Tab 2, pp. 19-20; PNG-West 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 19.6.
Management Fee Deferral

On pages 19 and 20, Tab 2, PNG presents the continuity of deferred charges for the Test Years 2020 and 2021. Line 31 of each page is the Management Fee Deferral.

In response to BCU IR 19.6 n the PNG-West 2018-2019 RRA proceeding, PNG provided the following response:

> Compared with the Actual 2017 amount, the AltaGas management fee for Test Years 2018 and 2019 is forecast to be lower by $0.3 million and $0.8 million, respectively. The reduction is attributable to a reduction in the cost pool allocator. PNG's MMF allocator in 2017 was 4.08%; its MMF allocator in Test Year 2018 is forecast to be 2.7%, further reducing to 2.2% in Test Year 2019…

44.1 Please clarify the nature of this deferral account and comment on any changes in cost pools or cost pool allocators from the prior Test Period.

Response:

This deferral account is being applied for in order to reduce the rate impact in Test Years 2020 and 2021 of approval of prudent and necessary costs of PNG. The size of the deferral is the difference between PNG's Shared Service Costs that have been historically been requested by PNG and allowed by the BCUC and the total amount that is being requested for Test Years 2020 and 2021.

For the prior Test Period, PNG was owned by AltaGas Ltd. when the 2018-2019 Decision was issued in August 2018. The Shared Corporate Service Costs reported in 2018-2019 were based on the cost pools and cost pool allocators from the MMF allocation used by AltaGas Ltd.

PNG was transferred to TriSummit Utilities Inc. (TSU, formerly ACI) in October 2018, and for 2019, as well as Test Years 2020 and 2021, the cost pools and cost pool allocators are based on TSU's costs and entities owned by TSU. Further information on the cost pools and cost pool allocators is included in Pages 3 to 5 of Appendix B of the Amended Application, as well as in the responses to Questions 32.1 and 32.2.

45.0 Reference DEFERRAL ACCOUNTS
PNG-West Division 2018-2019 RRA (PNG-West - 2018-19 RRA –)
Order G-151-18; PNG-West - 2018-19 RRA –Compliance Filing dated September 14, 2018
Compressor Engine Overhaul Costs

Directive 14 of Order G-151-18 states:

> PNG's request to record the compressor engine overhaul costs in a new rate base deferral account is denied. PNG is directed to capitalize these costs in accordance with US Generally Accepted Accounting Principles and depreciate over a period of 5 years once those assets are placed into service.

In the PNG-West-2018-19 RRA –compliance filing dated September 14, 2018, PNG stated:

> Further, the Decision 2019 Transfers to Capital – Administrative & General is greater by $7,000 from Test Year 2019 (Tab 1, page 2, line 15). These increases primarily reflect the directive to capitalize compressor engine overhaul costs in 2019 (Directive 14), and the reduction in new services and distribution mains in PNG(NE) (Order G-164-18, Directives 12 and 13, respectively).

45.1 Please confirm, or explain otherwise, that PNG is depreciating the compressor engine overhaul costs over a period of five years.

Response:

Not confirmed. PNG acknowledges that an unfortunate error has been made in the Amended Application as PNG applied a ten-year depreciation period instead of a five-year depreciation period for the compressor engine overhaul costs as per Directive 14 of Order G-151-18.

PNG apologizes for this error and proposes to amend the final regulatory schedules to reflect the correct depreciation period in compliance with the noted Order. The impact of changing to a five-year amortization period will result in an increase in the depreciation expense for these assets from $48,188 to $96,376 for each of Test Years 2020 and 2021.

I. SHARED SERVICES RECOVERY FROM PNG(NE)

46.0 Reference: SHARED SERVICES RECOVERY FROM PNG(NE)
Exhibit B-2, Section 2.11, pp. 81, 86, 89, 91; PNG-West 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 39.2.
Shared Services Recovery from PNG(NE)

On page 81 of the Amended Application, PNG states:

> PNG continues to apply the shared services cost allocation and recovery methodology as approved for use in Decision 2013. While there have not been any changes to this approved methodology, there have been, by design, changes to cost pools and cost allocators to reflect revised forecasts for base costs and financial and operating metrics for each test year under review.

46.1 Please explain if there have been any changes in circumstances for PNG and PNG(NE) since Decision 2013 that justify a review of the shared services methodology. If yes, please discuss the change in circumstances. If not, please provide an explanation for why the circumstances have not changed and elaborate on why the methodology is still appropriate.

Response:

PNG considers the shared services methodology as approved for use in Decision 2013 continues to remain appropriate. PNG submits that there have been no significant changes in the nature or extent of services provided by PNG for PNG(NE), and that there continue to be efficiencies from PNG providing such services on a centralized basis for the consolidated group. Further, the nature of operations for each of PNG and PNG(NE) have remained consistent over the years.

46.2 Please provide an estimate of the time and costs associated with conducting a review of the shared services methodology.

Response:

Based on costs incurred in 2012 for the last review of the shared services methodology, PNG estimates the cost to complete a review at between $65,000 and $70,000. Actual time for the review is not expected to take more than a few months, however, PNG notes that, as an input to the methodology, in the previous review an analysis of employees' actual time allocation between PNG and PNG(NE) was undertaken for a one-year period.

On page 86 of the Amended Application, PNG states that it "will be incurring annual sustainment costs" for the Maximo asset management system of approximately $260,000.

46.3 Please provide the amount, if any, of the Maximo sustainment costs incurred in 2019.

Response:

PNG incurred no sustainment costs on the Maximo asset management system in 2019. Under US GAAP qualifying license costs and the related software support and other development costs can be capitalized during the application development stage, which is why these costs have been capitalized rather than being expensed. PNG expects to go live in 2020 and any additional costs incurred after the go-live date must be treated as sustainment costs under US GAAP.

In relation to cost pool 721 – Administration, PNG states on page 89 that the "[o]verall cost pool increase of approximately $857,000 [is] due to a number of factors, including: JDE sustainment costs; higher Vancouver office rent; costs associated with transitioning to Microsoft 365; costs related to the HRIS; and general inflationary costs increases on **all** costs in this cost pool over Decision 2019 amounts. [*Emphasis Added*]

46.4 Please clarify whether inflationary cost increases were applied on all costs in this cost pool, including any on-off costs.

Response:

PNG applied inflationary cost increases to Actual 2019 amounts, not to Decision 2019 amounts, to costs in this cost pool, unless Test Year 2020 costs could otherwise be estimated with greater accuracy. For example, PNG could more precisely forecast JDE sustainment costs, Vancouver office rent, costs related to the HRIS and costs associated with transitioning to Microsoft 365.

In response to BCUC IR 39.2 in the PNG-West 2018-2019 RRA proceeding, PNG provided the following table:

Table 39.2 – Shared Service Composite Allocators

Test Year / Division	Customer Count		Employee Count		Rate Base		Composite Average w/o Time
	#	%	#	%	$	%	%
2019 Test Year							
PNG-West	20,401	48.8%	92	75.4%	143,323	63.7%	62.7%
FSJ	12,865	30.8%	15	12.3%	48,272	21.5%	21.5%
DC	7,285	17.4%	13	10.7%	28,806	12.8%	13.6%
TR	1,242	3.0%	2	1.6%	4,478	2.0%	2.2%
PNG(NE)	21,393	51.2%	30	24.6%	81,556	36.3%	37.3%
Total	41,793	100.0%	122	100.0%	224,878	100.0%	100.0%
2018 Test Year							
PNG-West	20,385	49.0%	92	75.4%	138,190	64.8%	63.1%
FSJ	12,723	30.6%	15	12.3%	45,110	21.2%	21.4%
DC	7,228	17.4%	13	10.7%	26,029	12.2%	13.4%
TR	1,242	3.0%	2	1.6%	3,828	1.8%	2.1%
PNG(NE)	21,193	51.0%	30	24.6%	74,967	35.2%	36.9%
Total	41,579	100.0%	122	100.0%	213,157	100.0%	100.0%
Actual 2017							
PNG-West	20,583	48.9%	90	74.4%	135,475	64.9%	62.7%
FSJ	12,870	30.5%	14	11.6%	43,351	20.8%	21.0%
DC	7,445	17.7%	13	10.7%	24,026	11.5%	13.3%
TR	1,235	2.9%	2	1.7%	3,202	1.5%	2.0%
PNG(NE)	21,550	51.1%	29	24.0%	72,990	35.0%	36.7%
Total	42,133	100.0%	121	100.0%	208,756	100.0%	100.0%
Actual 2016							
PNG-West	20,513	49.3%	89	73.6%	135,958	66.9%	63.2%
FSJ	12,666	30.4%	14	11.6%	40,287	19.8%	20.6%
DC	7,205	17.3%	13	10.7%	23,091	11.4%	13.1%
TR	1,246	3.0%	2	1.7%	3,069	1.5%	2.1%
PNG(NE)	21,117	50.7%	29	24.0%	68,076	33.5%	36.1%
Total	41,630	100.0%	121	100.0%	203,191	100.0%	100.0%

46.5 Please recreate the table above for each of 2018 and 2019 actuals and Test Years 2020 and 2021 forecasts.

Response:

Please see the table provided on the page that follows.

Test Year / Division	Customer Count		Employee Count		Rate Base		Composite Average w/o Time
	#	%	#	%	$	%	%
2021 Test Year							
PNG-West	20,658	48.9%	98	77.8%	164,810	64.6%	63.8%
FSJ	12,990	30.8%	14	11.1%	51,000	20.0%	20.6%
DC	7,353	17.4%	12	9.5%	33,261	13.0%	13.3%
TR	1,233	2.9%	2	1.6%	5,860	2.3%	2.3%
PNG(NE)	21,576	51.1%	28	22.2%	90,121	35.4%	36.2%
Total	42,234	100.0%	126	100.0%	254,931	100.0%	100.0%
2020 Test Year							
PNG-West	20,573	48.9%	98	74.8%	152,811	64.5%	62.7%
FSJ	12,907	30.7%	17	13.0%	48,167	20.3%	21.3%
DC	7,332	17.4%	14	10.7%	30,352	12.8%	13.6%
TR	1,235	2.9%	2	1.5%	5,580	2.4%	2.3%
PNG(NE)	21,474	51.1%	33	25.2%	84,099	35.5%	37.3%
Total	42,047	100.0%	131	100.0%	236,911	100.0%	100.0%
Actual 2019							
PNG-West	20,591	48.9%	94	74.0%	142,028	68.0%	63.7%
FSJ	12,910	30.7%	18	14.2%	44,902	21.5%	22.1%
DC	7,338	17.4%	13	10.2%	27,824	13.3%	13.7%
TR	1,238	2.9%	2	1.6%	4,309	2.1%	2.2%
PNG(NE)	21,486	51.1%	33	26.0%	72,990	35.0%	37.3%
Total	42,077	100.0%	127	100.0%	208,756	100.0%	100.0%
Actual 2018							
PNG-West	20,483	48.9%	92	75.4%	135,101	66.5%	63.6%
FSJ	12,815	30.6%	15	12.3%	43,642	21.5%	21.5%
DC	7,316	17.5%	13	10.7%	25,679	12.6%	13.6%
TR	1,243	3.0%	2	1.6%	3,281	1.6%	2.1%
PNG(NE)	21,374	51.1%	30	24.6%	68,076	33.5%	36.4%
Total	41,857	100.0%	122	100.0%	203,191	100.0%	100.0%

J. RATE BASE

47.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 97
2020 Planned – Recurring Capital Expenditures – Investigative dig cut-outs

On page 97 of the Amended Application, PNG states:

> For pipeline sections with a larger density of potentially significant anomalies, pipe replacement is more cost effective than on-going site-specific inspections and repairs…The forecast expenditure for 2020 of $1,021,000 represents the anticipated cost for cut-outs as a result of the four planned ILI runs and the need to outsource a large portion of this work due to internal resource constraints.

47.1 Please provide additional information regarding the proposed cut-outs, including: (i) location of cut-outs, (ii) length of replaced pipe, (iii) diameter of pipe, and (iv) existing pipe anomalies identified.

Response:

PNG intends to execute the 2020 ILI runs early enough in the year to be able to perform at least some associated digs to validate tool performance to specifications and to investigate the most injurious of pipeline feature indications.

While some investigative digs have been performed and repairs conducted stemming from the 2018 ILI runs, access and permitting constraints and other site-specific complexities have resulted in delayed inspections and repair response. For this reason, the specifics associated with anomalies and cutout length are not yet known.

Similarly, repair details from 2020 ILI runs will not be known until the runs are performed and the investigation digs completed.

As noted, the proposed cutouts for 2020 lie not only in PNG's 2020 planned ILI run sections, but also sections from 2 of PNG's 2018 ILI runs. Investigative digs and resulting cutouts are typically achieved over 2-3 years following an ILI run (due to limited construction 'seasons' or 'windows' each year).

Based on the foregoing, information for proposed 2020 cutouts is provided in the table that follows.

ILI Run Year	Section	Pipe Diameter	Length of Cutout Sections	Pipeline Anomalies
2018	MP0.0 - MP66.69	10"	3m-20m+	dents, rerounded dents, crack like features, metal loss features (external corrosion)
2018	MP311.55 - MP361.54	8"	3m-20m+	dents, possible rerounded dents, metal loss features (external corrosion)
2020	MP66.69 - MP137.64	10"	3m-20m+	dents, rerounded dents, crack like features, metal loss features (external corrosion)
2020	MP201.98 - MP209.2	16"	3m-20m+	dents, rerounded dents, crack like features, metal loss features (external corrosion)
2020	MP268.83 - MP273.45	10"	3m-20m+	dents, rerounded dents, crack like features, metal loss features (external corrosion)
2020	MP273.45 - MP311.55	8"	3m-20m+	dents, possible rerounded dents, metal loss features (external corrosion)

48.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 97
2020 Planned – Recurring Capital Expenditures – Unspecified mainline repairs

On page 97 PNG states:

> The five year average (2015-2019) expenditure for this type of work is $695,000 and reflects recent unplanned pipeline repairs/remediation (Salmon River, MP 250, etc.). With the increasing age of PNG-West's pipeline assets, along with increased scrutiny from not only within PNG, but also from regulators, insurers, and other stakeholders (Indigenous Nations, land owners, agencies with asset overlap, etc.), PNG-West can expect upward pressure on the timeliness and scope associated with unplanned repairs.

48.1 Please provide the unspecified mainline repairs costs for actual and decision 2015 to 2019 and forecast 2020 and 2021.

Response:

Please see the table that follows.

	2015		2016		2017		2018		2019		2020	2021
	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual	Forecast	Forecast
Unspecified mainline repair costs	260,000	296,274	266,310	-	271,970	619,585	605,351	1,447,617	344,549	536,921	663,987	677,378

48.2 In addition to potentially assessing the five-year average expenditure for this type of work, please describe how PNG has forecast the costs associated with unspecified mainline repairs for 2020 and 2021.

Response:

PNG has utilized a five-year average as the primary source of forecast for unspecified mainline repairs in 2020/2021, adjusting the base of the forecast to account for any exceptional circumstances that may have skewed the average and are not to be expected as regular occurrences in future years. PNG also gives consideration to the expected impacts of climate change as they pertain to seasonal impacts on pipeline assets, as well as information gained from expanded geohazard and integrity studies used to identify risk to PNG's mainline. Furthermore, PNG has incorporated into its most recent forecast any expected additional costs associated with third-party activity, coactive tenancy, increasing expectations around environmental protection, land owner notification, Indigenous Nations interests, and technical regulation for even the most emergent of repairs.

48.3 Please quantify or provide specific examples of the upward pressure on timeliness and scope that PNG has experienced with respect to its unplanned repairs.

Response:

The following discussion provides examples of unplanned repairs that had considerable upward pressure related to timeliness and scope compared to previous similar repairs.

Wade Road NPS 10 ML MP 268.8 and NPS 3 TP Washouts – Spring seasonal rain on snow events in March 2017 resulted in the creation of a new high velocity, high volume, stream channel that intersected, crossed, and travelled parallel to two of PNG's high pressure pipeline assets. This created high degrees of material transport from upslope areas that created problematic ponding adjacent to PNG's assets which resulted in significant undermining of pipeline bedding. High velocity, high volume flows across and parallel to PNG's pipelines resulted in significant bedding and cover material erosion and pipeline exposure. The length of the exposure created unsupported pipeline spans that were in need of immediate address. The exposed pipelines traversed land that had the combined interests of the Kitselas First Nation (IR5 land), the Ministry of Transportation and Infrastructure, the Regional District of Kitimat Stikine, BC Hydro, adjacent industrial operators, private landowners, and the BCOGC, all of which expressed specific interest and expectation associated with timely remediation design and construction that improved upon the pre-existing condition by ensuring design factors such as upslope geohazards and peak seasonal and historic hydrology were incorporated.

Kleanza Creek Crossing Replacement – The Kleanza Creek 3" DP pipeline crossing was originally a buried creek crossing that was exposed and ruptured as a result of extreme flooding in the fall of 2017. PNG installed a temporary pipeline in order to maintain gas service. There was considerable pressure from local residents and customers, the Ministry of Transportation and Infrastructure, BC Parks, and Indigenous Nations to enact a permanent repair in as timely a fashion as possible but in a way that would not negatively impact fisheries values in the stream, BC Parks values bordering the pipeline right of way, or a coactive First Nations led project adjacent to the exposed pipeline. In order to ensure the expectations and requirements of all stakeholders were held in high regard a number of crossing option feasibility studies had to be conducted and the final solution vetted and approved by a number of stakeholders. Fisheries and Oceans Canada (FOC) provided constant pressure to ensure all remnants of the previous pipeline crossings would be removed. PNG notes that there was some insurance coverage for this project.

Copper River NPS 10 ML MP 250 Relocation – The PNG pipeline had been relocated at this specific location on at least two other occasions in the past, with each iteration being limited to a marginal horizontal displacement away from the Copper River. At the time these solutions were considered appropriate by the stakeholders of the day and legacy practices such as leaving unmarked abandoned pipe in place were acceptable. During the most recent relocation stemming from extreme flooding in the fall of 2017, there were considerably higher expectations related to new alignment location, geotechnical and hydrotechnical considerations, the longevity of the proposed solution, extent of environmental protection, technical regulator and indigenous nations oversight, overlapping agency inputs, fisheries habitat impacts offsetting requirements, and the timeliness of overall project completion, including the removal of temporarily installed pipelines and previously abandoned assets. PNG notes that there was some insurance coverage for this project.

Pipeline System Improvements on Ridley Island – These project activities were partially a result of industrial project development, including rail line infrastructure, on Ridley Island that were in proximity to and across existing PNG pipeline system assets. The nature and scope of the development work by others had significant impact on not only PNG, but also other pre-existing island tenants such as Ridley Terminals and Prince Rupert Grain. This was a uniquely intrusive and unexpected project that could not have been reasonably forecasted. Given the firm timelines for the industrial project in conflict, and the interests of the landowner (Prince Rupert Port Authority) to expedite all activity, PNG experienced considerable pressure to complete all necessary works in as timely a manner as possible. This was inclusive of works directly associated with PNG's servicing of the new industrial facility (Ridley Island Propane Export Terminal), as well as other coincident needs for the existing PNG system. The impact of this project was pronounced by PNG's own system deficiencies on the Ridley Island System.

48.3.1 Please elaborate whether upward pressure on scope of unspecified mainline repairs may exceed PNG's ability to complete the repair scope within the test year. Please discuss any strategies PNG has implemented to mitigate this risk.

Response:

Any risk of an inability of PNG to compete unspecified mainline repairs in their final form in a given test year is not considered to be directly attributable to the upward pressure on scope. PNG is equipped through a combination of internal and external resources to react adequately and confidently. Risk to test year completion would be more directly related to the time of year of an unplanned repair, the potential requirement for permitting with the BCOGC and/or other regulatory bodies, and the nature of the repair required. At the very least, a temporary repair would be implemented and front end works on engineering, planning, and procurement for a permanent repair would be undertaken in the test year, with the permanent repair carrying over into the following year if required.

In order to mitigate risk associated with unplanned repairs and their associated scope and schedule, PNG continues to build positive relationships with regulators, stakeholders, contractors, and vendors, and continues to invest in our system integrity programs such as geohazard identification and management, line patrols, and third party activity management in order to proactively mitigate risk to the pipelines and reduce the potential for unplanned repairs. PNG has also made investments in its emergency response capability through an updated Emergency Response Plan, additional training and exercises. Finally, PNG notes that it has mutual assistance agreements in place with other utilities, if required.

49.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, pp. 98-99
2020 Planned – Non-Recurring Capital Expenditures – Transmission Mainline Repairs and Assessments

On pages 98-99 of the Amended Application, PNG states:

> With the recent emergence of natural gas pipeline crack detection tool technology free from need for liquid couplant (EMAT vs UT tools) and commercially marketed in diameters small enough to suite those of PNG Wests's operating transmission pipelines, the PNG ILI plan established as part of PNG's integrity management planning and associated regulatory compliance has been revised to incorporate EMAT use where possible…
>
> PNG has also been monitoring the Canadian Transportation Safety Board (TSB) investigation relating to Enbridge's natural gas pipeline rupture and ignition that occurred northeast of Prince George. PNG believes its past and planned use of EMAT aligns with the TSB's pipeline transportation safety advisory letter (617-02/19) that highlights the importance of stress corrosion cracking management…
>
> Forecast costs for both Test Year 2020 and Test Year 2021 have been based on a combination of vendor budgetary pricing, 2018 EMAT run actual costs, and the adjustment of variable costs…The 2020 costs will be for the actual ILI run execution, and the 2021 costs will be for final report deliverables and other associated trailing costs.

49.1 Please elaborate on and discuss the risks associated with SCC for PNG's pipelines and any risks associated with delays in completing work scheduled for transmission mainline repairs and assessments.

Response:

Fairly extensive near-neutral pH SCC has been found throughout the PNG transmission pipeline system between compressor station R1 and Terrace. Localized areas (colonies) of SCC have been found elsewhere. This is a result of the sustained presence of the required contributors to SCC (poor coating and sensitive metallurgy, corrosive environmental conditions, and tensile stress) along the pipeline. Prior to the first PNG EMAT run in 2016, SCC was found by chance during investigative digs intended to be looking for corrosion pits. Although SCC is slow propagating, due to the vintage and characteristics of segments of the PNG transmission system, SCC will be a growing concern until such time that all pipeline segments for which EMAT tools are available and inspected with the purpose of searching out SCC.

In addition to the risk of failure (during which areas of SCC will rupture, unlike areas of regular corrosion that will leak), delays in completing inspections and repairs may be considered as non-compliance by the BCOGC when considering PNG's integrity management plan and associated management of known SCC susceptibility.

Any deferred runs and repairs would have to be made up in subsequent years to regain compliance to plan, compounding cost impacts associated with future rate applications.

49.2 Please clarify how the recommendations made in the TSB's pipeline transportation safety advisory letter (617-02/19) have impacted PNG's approach to integrity management. Please discuss whether PNG has identified the SCC-susceptible pipeline segments within its system (e.g. due to use of polyethylene tape coating).

Response:

The recommendations in the TSB's pipeline safety advisory letter (617-02/19) have not appreciably impacted PNG's approach to integrity management. Given that PNG had previously identified SCC within its system, identified areas of high susceptibility due to the presence of polyethylene tape coating or other similar field applied external coatings of poor quality, and had implemented measures associated with SCC management, the letter highlighted that PNG is taking a reasonable and responsible approach to SCC. This, and other regulatory guidance around SCC management, has however further emphasized the need for continuous improvement and diligent focus in regards to SCC identification and repair.

49.3 Please elaborate on the technology changes which have allowed PNG to increase implementation of in-line inspections (ILI). Specifically discuss the range of PNG transmission pipeline diameters which have become suitable for ILI as a result of technology improvements.

Response:

It is PNG's belief that this question is specific to increased implementation of EMAT crack detection tool technology during in-line inspection. EMAT technology continues to improve in its use for crack detection in the natural gas pipeline industry. This is evident in the development of EMAT specific users groups chaired and attended by many of the major pipeline companies in North America and globally. Only as recent as 2016, however, have EMAT tool vendors began manufacturing and marketing tools in diameters usable by PNG. EMAT tools are now available in PNG pipeline diameter ranges from 10" to 16". Given the growing concern with respect to SCC related catastrophic ruptures industry, PNG's known history of SCC, heightened regulations, and now the availability of improved EMAT technology, it is critical for PNG to move forward with its proposed EMAT program.

49.3.1 Please discuss the changes to associated regulatory standards which have resulted in PNG's expanded use of ILI.

Response:

PNG has had an established and extensive ILI program since the 1990s. This program has been a significant component of PNG's overall transmission system integrity management plan, with baseline repeat run frequencies for each given pipe segment inspection of 7-10 years, aligning with industry standard. All high-pressure pipelines for which suitable free swimming ILI tools are available have been subject to inline inspection. Developments in tool technology and marketed minimum sizes are monitored and resultant opportunities to add more pipelines to the inspection regime are identified.

Current regulatory drivers that influence the continuous improvement of PNG's ILI program are the expectation for improving crack detection capability, the use of ILI to identify areas of environmentally induced stresses, and the incorporation of ILI for previously non-inspectable pipelines. Eventually, this will mean the inclusion of pipelines down to 3" diameter, and the need to modify aged pipeline designs to allow for successful in-line tool passage.

49.4 Please confirm whether ILI execution is typically completed on a regular frequency.

Response:

PNG states a default or baseline repeat ILI run frequency of 7-10 years. This aligns with the prescriptive frequency in the US and the adapted industry standard in Canada. This frequency is subject to change based on pipeline condition, corrosion or crack growth rate, prevalence of third party industrial activity around the pipeline, and other forms of integrity engineering judgement.

49.4.1 If yes, please discuss criteria used to established frequency interval for ILI execution. If no, please explain.

Response:

Please see the response to Question 49.4.

49.5 Please elaborate on whether PNG expects to incur capital costs associated with the retrofit of transmission pipeline segments in order to make them ILI compatible.

Response:

Yes, PNG has near future plans to retrofit two transmission pipeline segments that were previously ILI compatible but have not been for many years as a result of a past river washout and pipeline section abandonment. These capital retrofits are proposed for 2021 and 2022. Furthermore, PNG plans to continue reviewing those pipeline segments that are not currently ILI compatible and to find opportunities for improvement. The likely candidates for retrofit are the high pressure laterals of 4" diameter or greater that supply many communities and industrial customers on the PNG distribution systems. PNG is also staying abreast of ILI technologies and industry practices for smaller diameter segments/laterals in the event there are future retrofit opportunities.

49.6 Please elaborate how PNG forecasts the costs for this type of work and quantify the variable cost adjustments associated with pipeline segment length, terrain, area remoteness, etc.

Response:

PNG refers to past actual ILI run costs for each pipeline diameter as the starting basis for future run forecasts. Consideration is then given for pipeline segment length as this contributes significantly to tool vendor costs given direct relationship with the time in the field for both technician crews and the high cost tools, as well as the quantity of data collected to be analyzed. The data analysis and results provision are the highest cost contributors to the overall ILI run and with data sampling rates in excess of 1000 samples per square inch, even marginal increases or decreases in run length and pipeline diameter have a significant impact on cost. Terrain and area remoteness impact costs associated with accessibility for pre-run survey and the deployment and retrieval of above ground markers used for tool tracking. Areas with ease of access rely on pickup trucks and conventional survey and tool tracking technologies that are deployed and retrieved efficiently. Rough terrain will require the use of ATVs or UTVs, and extremely remote areas will require extensive helicopter and/or river boat use, complex and inefficient survey, and the use of advanced technologies for tool tracking. The use of helicopter access can have considerable efficiency and cost impacts associated with weather delays and the risk of resultant rework. In the event of the need for any tool re-runs, which can happen for variety of reasons, there are additional costs incurred. The impact of this is most appreciable for remote areas.

A glaring example of the costs associated with ILI runs of extreme terrain and remoteness is the 2018 8" MFL run from MP 311.5 – 361.5.

PNG takes learnings from the full spectrum of ILI complexities and costs and leverages those to inform the forecasts for future runs as best possible. These forecasts are then revised and supplemented by tool vendor and support contractor/consultant costs as proposals and bids are received and vetted.

49.6.1 Please discuss any strategies PNG has implemented to reduce the costs associated with ILI runs.

Response:

PNG continues to find ways to optimize the use of internal resources to support ILI runs. This includes both field resources and engineering and project management. PNG relies on a competitive bid process and has expanded the list of bidders in 2020 to ensure optimum results. Most notably, in 2020, PNG is pursuing a 3-year Master Services Agreement (MSA) with a lone tool vendor for EMAT runs to attempt to further reduce pricing.

50.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, pp. 99-100
2020 Planned – Non-Recurring Capital Expenditures – Salvus to Galloway Remediation

On pages 99-100 of the Amended Application, PNG states:

> This multi-year program is focused on addressing integrity concerns on the Prince Rupert NPS 8 transmission mainline commenced in 2018, with completion of a sophisticated and modern inline inspection, geo-hazard assessment, and front end access planning and mitigation works design…
>
> Following-up on the 2018 ILI run, PNG-West has identified a substantial quantity of metal loss and dent integrity related features that need immediate prioritization and address to comply with the CSA Z662 standard. PNG-West has also overlaid desktop studies completed in 2018 by a third-party engineering firm so as to understand risks due to geo-hazards such as landslide, rockfall, hydraulic scour or accretion, flood, and avalance…
>
> …full pipeline system remediation [is] expected to be completed by 2023. For 2020, PMG-West will focus on planning and addressing high-priority and urgent segments needing immediate repair and improving access to remote locations. PNG-West plans to advance an application to the BCUC in the second or third quarter of 2020 seeking a CPCN for the full execution of the project

50.1 Please provide an update on the expected filing timeline for the CPCN application with the BCUC and any other regulatory applications that are required e.g. permits and/or environmental assessment applications.

Response:

PNG intends to submit the CPCN application to the BCUC in June or July 2020. There is also a variety of permitting required by the BC Oil and Gas Commission for activities covered under the *Oil and Gas Activities Act*. This will include a blanket permit for on right-of-way pipeline integrity maintenance activities and a pipeline permit amendment for any activities requiring new right of way and/or temporary workspace. Additional permitting will be required for archeological field investigations and a BC Parks permit will be required for activities within an existing conservancy. Project consultation and notification with local First Nations, private land owners, CN Rail, Ministry of Transportation and Infrastructure (MoTI), and BC Hydro will be required. An environmental assessment with BC Environmental Assessment Office (BCEAO) will not be required but a Fisheries and Oceans Canada (FOC) authorization is expected to be required.

50.2 Please provide the alternatives that are available for the Salvus to Galloway Remediation project, the pros and cons and total costs associated with each alternative and ultimately why they were not proposed.

Response:

PNG will provide a full alternatives analysis in the CPCN application. At this stage, PNG is still assessing the interplay of the various technical studies, including those related to Inline Inspection Assessments, geohazards, access planning, pipeline design, project management, construction planning, environmental, archeology, and cathodic protection. For the purpose of the response to this question, PNG provides some high-level commentary on the alternatives evaluated to date.

Option	Cost Level	Pros	Cons
Repair highest risk corrosion features and dents, and *key* geohazards	Lowest	-Rectifies all immediate and high priority metal loss features -Addresses dents on a risk adjusted basis -Addresses the highest risk geohazards -Addresses ROW and vegetation management -Provides a 25-50 year solution	-*Some* residual risk of major failure, although likely an acceptable risk -Addresses legacy issues of deferred maintenance -Addresses regulatory compliance concerns
Repair highest risk corrosion features and dents, and *all* geohazards	Medium	-Rectifies all immediate and high priority metal loss features -Addresses dents on a risk adjusted basis -Addresses the all geohazards -Addresses ROW and vegetation management -Provides a 25-50 year solution	-*Lower* residual risk of major failure -Addresses legacy issues of deferred maintenance -Addresses regulatory compliance concerns
Repair *all* corrosion, dents, and geohazards to bring the pipeline to modern day standard	Highest	-As per above -Provides a 50+ year solution	-*Lowest* residual risk of major failure and regulatory non-compliance -Addresses legacy issues of deferred maintenance -Addresses regulatory compliance concerns
Replace the pipeline	Highest/Not Feasible	Given the access and environmental constraints in the rugged, remote area of the province, replacing the pipeline would not be feasible. PNG expects a major re-route would be required, and if feasible, would be > $1 billion with a multi-year environmental assessment. For this reason, it was dismissed as an option.	

50.3 Please identify any risks associated with delays to the timing of execution of the planned capital activities for this project.

Response:

The Salvus to Galloway repairs are an extremely high priority for PNG. Given the BCUC's approved funding in 2018-2019 for the Salvus to Galloway pre-development work, PNG has been able to conduct additional studies and better understand the magnitude of the risks. The following are the major risks identified that are considered a high priority and require immediate action:

1) **Catastrophic Pipeline Rupture from Corrosion and Dents:** Pipeline rupture associated with high risk dents or leak and loss of service associated with high wall loss corrosion features. PNG believes these risks are significantly higher than other pipelines in the industry.
2) **Catastrophic Pipeline Rupture from Geohazards**: Pipeline rupture associated with high risk geohazard. PNG believes these risks are significantly higher than other pipelines in the industry.
3) **Regulatory Non-compliance:** BCOGC orders stemming from the associated "Segment by segment Risk assessment". BCOGC order stemming from its "Aged Pipeline Assessment". BCOGC order stemming from a planned Integrity Management Plan Audit by the BCOGC.
4) **Interruption to Existing Customers:** The risk to having a weeks/months long outage in the Prince Rupert area impacting the ability to provide service for heat, hot water, and industrial processes. These risks are significantly higher than most other pipelines in North America.
5) **Industrial Project Growth delays in Prince Rupert:** PNG has had a number of industrial customers seek service in Prince Rupert region, including customers that may participate in the RECAP, that could be delayed without the repairs conducted.
6) **Impact to Economic Development and Industry Reputation:** Natural gas development is a major growth opportunity for Northern BC. With a recent pipeline failure in the region in 2018, and other major LNG and pipeline projects in development, PNG believes there is a risk of stakeholder resistance or project delays that could impact economic growth if a major failure were to occur.

In summary, PNG cannot ignore pipeline integrity issues that have evolved and become more pronounced over the past 30 years. Immediate action is required. This is highlighted by the recent study outcomes from the BCUC funding through the 2018-2019 Revenue Requirements Application. PNG believes the aforementioned risks could be elevated based on these recent findings.

50.4 Please list the significant project execution risks PNG has identified regarding this project. Please discuss any mitigation measures proposed to address these identified risks.

Response:

PNG completed a comprehensive risk workshop. As PNG considers detailed risk evaluations to be commercially and operationally sensitive information, it has submitted project risk and stakeholder registers, complete with associated controls and mitigations and listing of post-control residual risks, on a confidential basis along with the responses to BCUC Confidential IR No. 1.

50.5 Please provide any preliminary feasibility reports, risk assessment reports, engineering reports, costing reports completed regarding this project.

Response:

Given the sensitivity of detailed risk and integrity related materials, PNG has submitted the following documents on a confidential basis along with the responses to BCUC Confidential IR No. 1:

- Lauren Services Feasibility Report (without appendix documents)
- Lauren Services Design Basis Memorandum (without appendix documents)
- BGC Engineering Geohazard Mitigation Plan
- Lauren Services Risk Registry

50.6 Please provide a table with the forecast and actual (where applicable) capital costs for each year with project expenditures, including years other than the 2020 and 2021 test period. Please provide a summary of the scope of work expected to be completed in each year.

Response:

The following table provides the actual and forecasted costs to an assumed CPCN application approval in early Q2 2021. Due to significant scope growth identified as a result of 2018 and 2019 study, and the ongoing decisions related to final scope definition, PNG is not yet in a position to provide estimated capital cost for full pipeline remediation project. This will be provided in the CPCN application that is intended to be filed in June or July 2020.

	2018		2019		2020	2021	Project
$	Decision	Actual	Decision	Actual	Forecast	Forecast to CPCN Approval	Forecast to CPCN Approval
Salvus to Galloway Pipeline Remediation	361,700	307,199	566,323	555,815	1,898,690	2,218,500	4,980,204

Completed and forecasted scope of work to CPCN approval is as follows:

2018 – Preliminary geohazard identification and risk ranking, significant watercourse surveys, and preliminary environmental constraints cataloguing, inclusive of significant field study.

2019 – Overall remediation project pre-feasibility and FEED study, including options definition and investigation associated with pipeline mechanical repairs, geohazard mitigations, permitting, consultation, and project risk.

2020 – FEED study completion, detailed design and work packages, quantitative project risk assessment, permitting completion, commencement of ILI related repairs and access improvements.

2021 (to CPCN Approval) – Completion of detailed geohazard mitigation and line isolation improvement designs based on finalized scope, completion of critical access improvement works, and materials and services procurement.

Although it was originally intended to be executing significantly greater construction activities in 2020, than now projected, 2020 scope and work plans had to shift to further project development work due to overall identified scope growth for the complete multi-year pipeline remediation project.

PNG notes there are variances in the forecast expenditures for Test Year 2020 and 2021 from those in the Amended Application of $1,451,509 and $2,528,969, respectively, and proposes adjusting the final regulatory schedules to reflect these updated amounts.

50.7 Please provide detailed information regarding the extent of the metal loss and dent integrity features identified in 2018. Please elaborate under which section of the CSA Z662 standard is this segment of pipe considered non-compliant.

Response:

The 2018 inline inspection identified the following total quantity of metal loss and dent integrity features.

ILI Feature	Quantity Identified During Tool Run	Prioritized Feature Quantity
Dent	711	116
Metal Loss	6,822	12

High priority for inspection and repair has been established based on the following criteria:

- Dents and their categorization and treatment are described in CSA Z662-19 in Section 10.10.4. Definition of dents as defects are per Section 10.10.4.2 and associated acceptable repair methods in Table 10.2. The 116 prioritized dent features are either defined as defects requiring inspection and repair under CSA Z662 or were identified by the tool vendor analysts as having concerning characteristics in need of investigation.
- Corrosion imperfections and their treatment are described in CSA Z662-19 in Section 10.10.2 and additionally within supplementary technical resources API 579, ASME B31.4, and BSI BS 7910 for alternative depth and length interaction criteria. The 12 prioritized metal loss features have a Predicted Failure Pressure Ratio (FPR) of 1.25 or less, where FPR is defined as the predicted burst pressure of an anomaly divided by the maximum allowable operating pressure of the pipeline.

50.7.1 Please confirm whether or not PNG has been directed by any regulatory authority (e.g. BC OGC) to complete any of the remediation work being proposed.

Response:

While PNG has not had any recent orders by the BCOGC regarding this segment of pipeline, orders have been issued in the last 20 years directly associated with this pipeline segment and its overall state of integrity and PNG risk management. Furthermore, the historical rate of failures on this pipeline segment has drawn additional specific and focused attention from the BCOGC. Specific focal points have been on exposed and unsupported pipe, low depth of cover, geohazard identification and management, right of way access and vegetation management, and the consideration for areas of pipeline relocation. This segment of pipeline is currently subject to a BCOGC mandated risk assessment that must give consideration to both static and dynamic data and give address to the following threats and consequences as outlined in CSA Z662 and ASME B31.8S:

- External corrosion
- Weather and outside force (geotechnical and hydrotechnical)
- Mechanical damage
- Safety
- Business continuity
- Environment

Furthermore, this pipeline segment has been selected by the BCOGC for full condition review under their "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 greater. Areas of focus will include:

- ILI history, including technologies used and frequency
- Direct Examination (Dig) history and response, including drivers (ILI, emergency, geohazard)
- Repair history, including drivers (ILI, emergency response, proactive mitigation)
- Geotechnical identification and management
- In-Service pressure testing history
- Fitness for Service assessments and response
- Engineering Assessment reports and response
- Other relevant integrity records that demonstrate the condition of the pipeline in accordance with CSA Z662 such as cathodic protection results, depth of cover surveys, crossing surveys, etc.

Given information aggregated to date within the Salvus to Galloway Remediation project, PNG believes there is significant risk of further and fairly immediate orders from the BCOGC if it cannot be demonstrated that a fulsome plan is in place for the overall safe and reliable operation of this pipeline.

50.8 Please clarify whether the decision to file a CPCN application with the BCUC for this project was made due to the capital cost estimate for the project, the scope of the project, a public interest component of the project, and/or some other criteria.

Response:

PNG submits that, given the outcome of some of the BCUC-approved studies in 2018-2019 on this pipeline, PNG became aware of the pressure on the scope and potential costs needed to repair the pipeline segment and determined that a CPCN would be required. This is also in line with the BCUC's requirement of a CPCN application for larger scale, multi-year projects and programs.

50.9 Please confirm the level of scope definition (cost estimate class) for the forecasted 2020 and 2021 costs included in the RRA for this project.

Response:

The 2020 and 2021 scope and forecasted costs provided in the table below are at Class 3 level of definition to get the project development to the point of the CPCN application and to progress time sensitive pipeline risk mitigation and procurement activities up to an assumed CPCN application approval in early Q2 2021. These costs and scope progression are required in order to avoid risk to a short and rigid 2021 construction schedule.

2020 and 2021 (to CPCN approval) costs and scope are as outlined in response to Question 50.6, with forecasted quarterly spend as follows:

	2020				2021 to CPCN Approval		Total 2020/2021 To CPCN Approval
	Q1	Q2	Q3	Q4	Q1	Q2	
Forecasted Cost	368,500	285,400	759,900	484,900	1,647,600	570,900	4,117,200

50.10 Please discuss whether the potential outcome of the RECAP process could have an impact on the scope of work for this remediation project. Specifically, would the reactivating and reinforcing project activities envisioned as part of the RECAP proceeding also address integrity concerns on this segment of pipeline? If so, please elaborate how PNG has considered potential RECAP related projects when establishing pipeline integrity Capital Expenditures currently included in this RRA.

Response:

PNG submits that the work on Salvus to Galloway is required irrespective of the outcome of a RECAP auction. PNG is also cognizant that additional industrial load in Prince Rupert will put additional schedule pressure on PNG to have the integrity work largely completed prior to the Commercial Operations Dates of the new industrial loads. Under this scenario, given there will be higher flows and higher pressures, PNG will have less line pack in the system and restricted ability to work on the pipeline for such work will require cutting the pipe without service interruption. The degree of complexity and interplay is also dependant on the volumetric flow with the new industrial customers and the locations within the Prince Rupert region. Ultimately, any new industrial customers with early TSA dates could have some effect of accelerating the timeline, although only modestly given the impending pipeline integrity concerns. PNG emphatically believes this segment of pipeline requires immediate investment irrespective of future industrial growth.

51.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 100
2020 Planned – Non-Recurring Capital Expenditures – Compressor Station Upgrades

On page 100 of the Amended Application, PNG states:

> A number of compressor station upgrades across the PNG-West system that have been deferred, but must now proceed to keep the facilities in a safe operating condition. Required activities include: installing new isolation valves at R3 compressor station – this is required to address safety and maintenance issues;

51.1 Please discuss any risks associated with delays to the timing of execution of the planned capital activities for this project in both 2020 and 2021.

Response:

PNG 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 safety risks. The main risks associated with delays to the project are that PNG cannot conduct the necessary maintenance on its equipment, including safety equipment. In addition, due to the configuration of the pipework, and the existing leaking valves, if a fault condition was to result in an Emergency Shutdown situation, the leaking valves would allow the pipework that is upstream and downstream of the station to constantly vent, until a technician can attend the site and resolve the situation. This could potentially take as long as 4 hours. These are simply not acceptable risks when operating high pressure pipeline facilities, so further deferral is not an option. This project is due for delivery and completion in 2020.

51.2 Please elaborate how PNG prioritizes the various compressor station upgrade activities. Has PNG developed a plan to guide decision making regarding execution of these upgrade activities for 2020 and 2021 and beyond?

Response:

On a regular basis, the management/engineers and technicians responsible for these sites have meetings to review the condition of the site operations from an asset management, safety, environmental and reliability perspective. The team develops plans for conducting any necessary works, based upon criticality, available resources, and any third party information, and then prioritize the work accordingly. PNG has developed an initial five-year plan for the works on the compressor stations, which included the activities for 2020 and 2021 and up to 2024. With PNG's CMMS-Maximo asset management system, PNG has further tools to make condition assessments, review reports, and prioritize activities.

51.3 Please clarify whether the safety and maintenance issues that the installation of new isolation valves at R3 will address. Please provide additional detail regarding the scope and schedule of this work. Please elaborate on the alternative solutions PNG considered in order to address the safety and maintenance issues identified.

Response:

This project is expected to address all safety and maintenance issues that have been highlighted by the installation of the new Emergency Shutdown valves. For more details on the issues, please see the response to Question 51.1.

The existing valves that are installed are welded in, which makes replacement almost impossible while keeping the gas flowing through the system. One alternative would be to utilize a more expensive double stopple and bypass arrangement to complete the repairs – this would be much more costly, in the region of an extra $200,000. As an another alternative, PNG attempted to seal the valves, utilizing sealants, with its own technicians and external experts to undertake the necessary repairs, however this was not successful.

The project is currently scheduled to be implemented during Q3/2020. The scope of this project is to:

- Install one flanged Emergency Shutdown ball valve on each of the suction and discharge legs on the compressor side of the existing valves. These valves will allow for adequate isolation of the compressor station into the future.
- Install spectacle blinds on each leg to allow ease of isolation in the future, should it be required.
- Install pressurization valves around each of the main isolation valves to maintain the seal integrity. Good industry practice is to not open a ball valves with greater than 30 psi pressure difference across them.
- Move/install the necessary instrumentation and electrical services for this modification.

52.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 100
2020 Planned – Non-Recurring Capital Expenditures – LNG Canada Let Down Station #1

On page 100 of the Amended Application, PNG states:

> PNG-West anticipates entering in to a GSA in the first quarter of 2020, well in advance of executing the full scope of the project and plans to make application to the BCUC seeking approval for a CPCN for this project.

52.1 Please provide a schedule of project milestones, including preliminary engineering design initiation, large equipment procurement, BCUC CPCN application submission, construction completion, commissioning and gas delivery. Please also include the expected timeline for other regulatory applications (e.g. permits and/or environmental assessment applications).

Response:

Please see the table that follows.

	Start	Completion
Engineering (to IFC)	Mar-19	May-20
Permitting (BCOGC)	Dec-19	Aug-20
Long Lead Procurement	Apr-20	Aug-20
Commercial Agreement	Jan-20	May-20
CPCN Application	May-20	Jul-20
General Procurement	May-20	Jul-20
Construction	Jun-20	Sep-20
Gas Delivery	Jun-21	

52.2 Please discuss any risks associated with delays to the timing of execution of the planned capital activities for this project.

Response:

PNG believes there is minimal risk to the timing of planned capital activities for this project. There is an executed backstop agreement in place that is supporting engineering, permitting, planning, and long lead procurement activities while a long-term commercial agreement is executed to support further works. The commercial agreement is presently in draft status and actively being worked through to completion by both PNG and the prospective customer. This process has had some minor impacts associated with COVID-19 but it is expected that the commercial agreement will be in place by May 2020. PNG's intent is to submit a CPCN application following finalization of the commercial agreement. Materials and service requisitions and associated bid processes to support construction are complete or underway. The gas delivery date will be formalized within the commercial agreement and will be directly linked to the overall project progress schedule of the overall LNG Canada construction deliverables by the project EPC contractor.

52.3 Please list the significant project execution risks PNG has identified regarding this project. Please discuss any mitigation measures proposed to address these identified risks.

Response:

PNG does not believe there to be any significant risks to the execution of this project. The project scope and magnitude, potential constraints, and identified potential low-impact risks are very similar to those of the successfully delivered LNGC LDS#2 project in 2019.

The only unique consideration is the current COVID-19 situation, which is not expected to have any appreciable impact on the project, including planned gas delivery date. At present date, regular project interface meetings have been maintained and site interface engineering continues to progress.

Risks and mitigations have been identified within project development documentation submitted in response to Question 52.4.

52.4 Please provide any preliminary feasibility reports, risk assessment reports, engineering reports, costing reports completed regarding this project.

Response:

Please refer to the following list of documents provided for BCUC reference:

Document	Study/Report Attachment
Project Options Assessment	Attachment BCUC 1.52.4a – LDS1 Lauren Scope Options
Project Design Basis Memorandum	Attachment BCUC 1.52.4b – LDS1 Lauren Design Basis
Project Basis of Estimate – includes feasibility, scope, and risk information	Attachment BCUC 1.52.4c – LDS1 Lauren Basis of Estimate
Class 3 Cost Estimate	Attachment BCUC 1.52.4d – LDS1 Lauren Class 3 Estimate

52.5 Please clarify over how many years this multi-year project is expected to extend. Please provide a table with the forecast and actual (where applicable) capital costs for each year with project expenditures, including years other than the 2020 and 2021 test period. Please provide a summary of the scope of work expected to be completed in each year.

Response:

This project is expected to be completed in mid-2021, with projected gas delivery in June of that year. Cost outlay is per the following table. Scope completion in each project year is per the milestone table provided in response to Question 52.1.

	2019		2020	2021	Total Project Cost Forecast
	Decision	Actual	Forecast	Forecast	
LNG Canada Let Down Station #1	-	$48,370	$1,147,825	$217,394	$1,413,590

52.6 Please clarify whether the decision to file a CPCN application with the BCUC was made due to the capital cost estimate for the project, the scope of the project, a public interest component of the project, and/or some other criteria.

Response:

PNG notes that it considered seeking approval for this project under this Amended Application and not filing a CPCN. However, following the BCUC's Decision on PNG's 2018-2019 Revenue Requirements Application (Order G-151-18) whereby the CPCN requirements were addressed, PNG determined that a CPCN application would be filed given the magnitude and scope of the project, as well as the public interest component of the project. The CPCN application will be in line with the approach taken in 2019 with the filing of a CPCN application for the very similar LNG Canada LDS#2 project.

53.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 101
2020 Planned – Non-Recurring Capital Expenditures – Geographic Information System (GIS)

On page 101 of the Amended Application, PNG states:

> The overall project cost is estimated at $2.4 million that has been incurred over three year (2018-2020) planned implementation period. Project costs are being shared by PNG West and PNG(NE) service areas. The project is on-schedule and on-budget…
>
> In 2020, PNG will be migrating the remaining 40% of the distribution asset data into the ESRI system. Upon completion, PNG will focus on applications, reporting, interfaces, Q/A and field device implementation. PNG will also finalize its sustainment model and process changes to ensure the GIS system is up-to-date and accurate in future years.

53.1 Table 3 in the 2018-2019 PNG West RRA decision[1] includes a breakdown of the consolidated GIS costs allocated to each division and the allocator. Please provide a revised table that also includes columns for actual 2018 and 2019 costs and forecast 2020 costs with an explanation for any variances from budget.

Response:

Please see the table that follows. PNG remains on schedule and on budget to deliver a completely functional GIS at the end of 2020.

	Allocation	2018		2019		2020		Total	
	Forecast	Forecast	Actual	Forecast	Actual	Forecast	Projected	Forecast	Projected
PNG-West	62.34%	$ 441,000	$ 449,242	$ 671,000	$ 658,565	$ 399,500	$ 403,694	$ 1,511,500	$ 1,511,500
PNG(NE) - FSJ/DC	36.40%	$ 242,000	$ 212,884	$ 377,000	$ 355,372	$ 233,300	$ 284,044	$ 852,300	$ 852,300
PNG(NE) - TR	1.26%	$ 8,700	$ 7,670	$ 13,500	$ 13,612	$ 8,100	$ 9,017	$ 30,300	$ 30,300
Total	100.00%	$ 691,700	$ 669,796	$ 1,061,500	$ 1,027,549	$ 640,900	$ 696,755	$ 2,394,100	$ 2,394,100

53.2 Please clarify what is the estimated ongoing annual costs of maintaining an accurate GIS system in future years.

Response:

PNG estimates the annual cost of maintaining an accurate GIS to be $250,000, based on the cost of: (i) maintaining software licenses ($50,000); (ii) maintaining servers and other IT infrastructure ($40,000); (iii) technical support from AUI's GIS staff ($40,000); and (iv) additional system improvements ($120,000).

[1] https://www.bcuc.com/Documents/Proceedings/2018/DOC_52226_G-151-18-PNGW-RRA-Reasons-for-Decision-Redacted.pdf

54.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, pp. 101-102
2020 Planned – Non-Recurring Capital Expenditures – High Voltage Alternating Current Mitigation

On pages 101 and 102 of the Amended Application, PNG states:

> A high-voltage power line is being installed over a PNG-West in-service 6" pipeline in Kitimat. In order to mitigate the effects of alternating current (AC) on this pipeline, a grounding system must be purchased and installed to reduce the predicted induced voltage down to safe levels.

54.1 Please provide a table with the forecast and actual (where applicable) capital costs for each year with project expenditures, including years other than the 2020 and 2021 test period. Please provide a summary of the scope of work expected to be completed in each year.

Response:

The scope of work for this project will be:

- Development and finalization of the grounding design to deal with anticipated induced voltage, including any necessary site visits.
- Procurement of necessary long lead items – grounding rods and AC decoupler.
- Securing necessary land permits and authorizations.
- Procurement of the remaining necessary materials – including wiring and other materials necessary for creating grounding system.
- Installation of the equipment at the site, including necessary attachment to the pipeline system.

The project is due to be completed in Test Year 2020. As per the table below, the forecast spend for 2020 is $159,316; there is no forecast spend for this project in 2021.

	2020		2021	
	Planned ($)	Actual spend ($) Year to Date	Planned ($)	Actual ($)
Project Costs	159,316	22,986	0	0

54.2 Please elaborate which utility or company is responsible for the installation of the high-voltage power line.

Response:

BC Hydro is installing this new line from an existing substation (which is being upgraded) to supply LNG Canada's new LNG facility in Kitimat, BC. PNG's existing pipeline will run parallel to this newly installed line. As a result, the PNG line will be subjected to unacceptable levels of induced Alternating Current.

54.3 Please clarify PNG's standard practices with respect to the installation of high-voltage power lines in proximity to its pipelines.

Response:

PNG follows the guidance in the CSA Z662-19 standard, which has been adopted into the BC Pipeline Regulation under the *Oil and Gas Activities Act*. The standard recommends trying to avoid running parallel to high-voltage lines or, if it is necessary, to mitigate against the induced current.

54.4 Has PNG pursued, received or expects to receive any compensation for having to mitigate the induced voltage on its pipeline?

Response:

PNG has attempted to obtain compensation and has not been successful, therefore PNG is not expecting to receive any compensation for the purposes of mitigating the induced voltage as a result of this installation.

55.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, pp. 102, 103 and 110
2020 and 2021 Planned – Non-Recurring Capital Expenditures – MP 195.9 Exposed Pipe Lowering and MP 297 Exposed Pipe Remediation and MP 208 Rock Armouring

On page 102 of the Amended Application, PNG states, "the exposed pipe is under a regular monitoring program and is planned for remediation via lowering."

On page 103 of the Amended Application, PNG states "The intent of the first phase of this remediation project is to perform the front-end engineering analysis, options and feasibility assessments, detailed design, and permitting to execute remediation works in the following year".

On page 110 of the Amended Application, PNG states:

> A short segment of transmission pipeline at MP 208 is at risk of exposure and destabilization as a result of river bank migration and bank erosion. The area is under a current monitoring program but river hydrology and ongoing erosion suggests future action to protect and reinforce the asset will be required.

55.1 For each of the MP 195.9 Exposed Pipe Lowering, the MP 297 Exposed Pipe Remediation and the MP 208 Rock Armoring projects, provide the total project costs by year and the scope of work to be completed in each year.

Response:

Please consider the following information:

MP 195.9 Exposed Pipe Lowering

- Projected Costs for 2020 = $200,600
  The scope is to perform the physical replacement for this year.

MP 297 Exposed Pipe Remediation

- Projected Cost 2020= $175,500
  The scope is to perform detailed Engineering and Design. To perform an options analysis and provide detailed drawings on the selected options and permit for 2021.
- Project Cost 2021= $783,000
  The scope is to perform the physical execution of the selected option from the 2020 Engineering and Design work.

MP 208 Rock Armouring

- Project Cost= $203,800
  The scope is to physically execute on installing rock armouring to protect the pipeline from erosion on the riverbanks to prevent exposure of the pipeline. This will also include the need to perform hydraulics to ensure the correct amount and type of rock armouring used.

56.0 Reference RATE BASE
Exhibit B-2, Section 2.13.1.1.1, p. 102.
2020 Planned – Non-Recurring Capital Expenditures – Information & Data Management Systems – Management of Change

On page 102 of the Amended Application, PNG states:

> PNG has also commenced a management of change (MOC) initiative to further develop and update PNG's current management of change (MOC) system. In 2020, $96,000 has been budgeted for project activities that include document and standard development, electronic platform implementation, and company wide training. PNG anticipate that the improved platform will enable it to plan, track, and audit any system changes and to process safety risks with a capability that is aligned with industry best practices and API RP 1173.

56.1 Please elaborate on the MOC initiatives and the activities to update the current MOC system.

Response:

PNG is introducing a management strategy and procedure that establishes guidelines and minimum requirements for managing temporary or permanent change. This strategy and procedure applies to all changes that may occur to a PNG facility. Change includes all modifications to equipment, process safety information, procedures, and process conditions other than "replacement in kind" and is inclusive of changes to process, facilities, technology, equipment, and personnel associated with asset management and operation. This procedure does not address Organizational Management of Change such as organizational restructuring or changes to the personnel occupying various positions. PNG is currently in the initiation phase of the project, working with stakeholders to ensure appropriate inclusion of all aspects of the business. PNG expects to roll out a draft portion of the process in early summer (June 2020) and a digital version by the end of 2020.

The MoC initiative will incorporate a digital platform that will, in comparison to PNG's current paper-based and extent-limited process, provide significant improvement in the ability to document, retain, and manage change related decisions and records. The proposed improvements will better align PNG to the change management related regulatory requirements of the BCOGC and TSBC and the associated content of CSA Z662 Annex N.1.6 , Z662 Section 3.1.2, and API RP 1173.

56.2 Please provide a breakdown of the total project costs by year and between expenses and capital costs.

Response:

PNG has contracted Gateway Consulting Group to support the development of the MoC procedure. To date, the costs incurred (2019) have been $50,000 for MoC procedure development. The 2020 costs for an on-premise software license, maintenance and deployment are forecast to be $22,500, with a site installation cost of approximately $12,500. Additional services required are consulting and configuration, train the trainer and a user training guide. These additional services will incur a 2020 cost of $39,000 bringing the expected 2020 costs to $74,000. PNG will incur additional internal costs associated with document and standard development and implementation, bringing the projected project cost inline with the current budget.

Costs associated with original platform, policy, and management system development and implementation will be capitalized as allowed under US GAAP. Future year sustainment costs are projected to be <$10,000 and will be incurred under operating expense.

57.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.1, pp. 98, 107
2020 and 2021 Planned – Non-Recurring Capital Expenditures – Computer Hardware/Software

The forecast Computer Hardware/Software capital expenditures are $218,297 in 2020 and $192,700 in 2021.

57.1 Please identify the 2020 and 2021 computer hardware/software capital expenditures that relate to specific projects.

Response:

Please see the table that follows.

	2020	2021
Terrace Server Replacement	61,200	
Terrace Data Storage Replacement		40,000
Upgrade the AV Equipment in Terrace Meeting Room	20,400	
42" Plotter Printer replacement (Eng. & Drafting)	18,360	
Scanner replacement (Eng. & Drafting)	25,500	
Necessary PNG website upgrades	28,883	
Replacement of iTron meter reading handhelds - end of life		90,000
Non-specific project expenditures	63,954	62,700
Total Computer Hardware and Software	218,297	192,700

58.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 105
2021 Planned – Recurring Capital Expenditures – Mobile/Heavy Equipment

On page 105 of the Amended Application, PNG states, "Seven replacement vehicles will be acquired during Test Year 2021 all of which meet PNG-West's established criteria of 8 years or 160,000 kms."

58.1 Please provide a breakdown of the decision and actual 2015 to 2019 and forecast 2020 and 2021 Mobile/Heavy equipment costs between mobile and heavy equipment purchases.

Response:

Please see the table that follows.

	2015		2016		2017		2018		2019		2020	2021
	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual	Decision	Actual	Forecast	Forecast
Mobile	479,000	497,526	351,594	401,472	344,500	323,001	288,660	272,058	246,993	297,828	569,160	821,916
Heavy Equipment	347,000	338,747	400,860	404,952	285,000	314,211	86,653	36,750	-	-	1,329,713	478,584
Total	826,000	836,273	752,454	806,424	629,500	637,212	375,313	308,808	246,993	297,828	1,898,873	1,300,500

58.2 Please discuss any risks associated with delaying the planned 2020 and 2021 heavy equipment purchases.

Response:

The risks associated with delaying Heavy Equipment purchases in 2020/2021 are significant. First, as these are all replacement purchases (not additional pieces of equipment), PNG could expect to see a significant increase in maintenance and repair costs to existing, aging equipment should PNG delay the 2020/2021 purchases. Two Kenworth trailers and associated cranes that are being replaced as part of this price control review will be 13 years old at the time of replacement which is greater than our recommended replacement period of 10 years old. These projects were deferred from the last revenue requirements application, however the costs of repairs are becoming more expensive due to age and modes of failures being experienced on these units.

With increased repair costs, comes increased reliance on rental equipment and/or contractors – driving-up PNG's associated costs and risks. Also, if PNG were delay these purchases, and see increased unplanned downtime due to breakdowns/repairs, the Company could expect to see delays to the execution of works, including integrity management activities on the high pressure and distribution assets.

58.3 Please discuss if PNG's vehicle replacement criteria include mobile equipment and if so, the specific criteria that are applicable.

Response:

PNG's mobile equipment is subject to replacement every eight years or 160,000 km, which ever comes first. Similar to PNG's mobile fleet, PNG's heavy equipment fleet also has specific replacement criteria. However, as our heavy equipment fleet is quite varied compared to our vehicle fleet, each piece of equipment is reviewed and criteria is set based on relevant factors - typically one or a combination of the following: age, mileage, operating hours, and/or annual repair costs.

Below is an extract from PNG's asset management strategy for heavy equipment which documents the criteria for a number of the pieces of heavy equipment.

Equipment	Qualifying limits
Kenworth Tractor Limits	10 Years or 500,000Km whichever comes first
Bobcat Skid/Steer	15 Years
Mini-excavators	10 Years
Backhoes	15 Years for construction crew, 20 years for snow clearing machines
Trailers	15 years for heavy duty trailers, 20 years for light duty trailers
Excavators	15 years
Dwitch Trencher	30 years
Argo	15 Years
Forklift	20 years
Welder Unit	20 years or 8000 hours of Operation whichever comes first
Air Compressor	25 years or 10,000 hours of operation whichever comes first
Cat Sideboom	Until uneconomical to repair (>$30,000 in annual spend on machine repairs, two years in a row)
D6 Cat Doozer	Until uneconomical to repair (>$30,000 in annual spend on machine repairs, two years in a row)
ETV Canopy	25 years
River Boat	20 years or 1500 hours of engine operation, whichever comes first
Side by Side	12 years or 5000 hours of operation, whichever comes first
Light Plant	15 years
Hydrovac	15 Years
Ground Thaw Unit	12 years or 3000 hours of operation, whichever comes first

59.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 108
2021 Planned – Non-Recurring Capital Expenditures – Transmission Mainline Repairs and Assessments

On page 108 of the Amended Application, PNG states:

Key EMAT ILI runs and analysis planned for 2021 are:

Description	Amount
EMAT ILI Run from R4 to MP 209 (Final Report)	$214,000
EMAT ILI Run from R2 to R3 (Final Report)	$287,000
EMAT ILI Run from PLS to MP 273 (Final Report)	$165,000
EMAT ILI Runs - R1 - R2 12" Loop	$915,000
EMAT ILI Runs - R2 - R3 12" Loop	$915,000
EMAT ILI Runs - R3 - R4 12" Loop	$397,000

59.1 Please provide the length (km) of the ILI runs planned for 2021.

Response:

Please see the table that follows.

ILI Segment	Segment Length (km, approx.)
EMAT ILI Run - R1-R2 12" Loop	40.5
EMAT ILI Run - R2-R3 12" Loop	40.5
EMAT ILI Run - R3-R4 12" Loop	6.75

59.2 Please elaborate on the scope of the Final Report deliverable. Please provide a breakdown of the Final Report costs forecasted in the table above. Please provide a sample report from a recent EMAT ILI Run.

Response:

The Final Report deliverable is the provision of the entire EMAT ILI data set from the inspection tool vendor, along with all analysis and recommended inspection location information developed by their analytics and integrity engineering teams. The fee schedule is outlined in mutually agreed commercial contract documentation and is marginally variable from one tool vendor to another. Generally speaking, 25% of the overall contract value is withheld and released upon receipt of the final report.

Given the sensitivity of detailed risk and integrity related materials, PNG has submitted the final report completed by TD Williamson of the EMAT run for R1 – R2 on a confidential basis along with the responses to BCUC Confidential IR No. 1.

60.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 109
2021 Planned – Non-Recurring Capital Expenditures – Compressor Station Upgrades

On page 109 of the Amended Application, PNG states:

> A number of compressor station upgrades across the PNG-West system that have been deferred, but must now proceed to keep the facilities in a safe operating condition. Required activities identified for 2021 include…replacement of R1 gas actuated valves ($775,000).

60.1 Please clarify whether further upgrades, besides those activities listed in this RRA, are necessary to keep the R1 facility in a safe operating condition.

Response:

PNG believes that the submissions made in this regulatory application, both in the proposed operating and capital budgets to keep the R1 facility in a safe operating condition, are adequate for the test period. Further upgrades will be required in the future to keep this equipment in a safe operating condition from an asset integrity and reliability perspective – approvals for such upgrades will be sought as necessary as they are identified.

60.2 Please elaborate on the replacement of gas actuated valves activity. Has this upgrade activity been mandated by a regulatory authority as part of an emission reduction effort?

Response:

This upgrade has been mandated by a regulatory authority as part of an emission reduction effort. The relevant regulations are Province of British Columbia, Regulation of the Board of the Oil and Gas Commission, *Oil and Gas Activities Act* 286/2018.

60.3 Please provide in table format the decision and actual capital and operating costs related to Compressor Station Upgrade projects for years 2015 to 2019, with an explanation for any variances.

Response:

Please see the table that follows.

	2015			2016			2017			2018			2019		
	Decision	Actual	Variance	Decision	Actual	Variance	Decision	Actual	Variance	Decision	Actual	Variance	Decision	Actual	Variance
Compressor Station Upgrades	302,220	429,655	(127,434)	204,000	147,656	56,344	701,534	424,198	277,336	1,771,794	2,457,096	(685,302)	387,173	414,759	(27,587)

All costs related to compressor station upgrade projects are capitalized; therefore, there are no additional operating costs to report in the table above. In 2015, most of the variance ($73,000) is associated with one project where the project scope increased as the project proceeded. Variances amounting to approximately $35,000 are associated with unbudgeted projects that had to be completed to ensure the operability of the site.

In 2016, the underspend variance is associated with projects being delivered in a more efficient manner than anticipated at the start of the year.

In 2017, the underspend variance is associated with the delivery of two major projects being delayed due to the late arrival of long lead items essential to the completion of those projects.

In 2018, the overspend variance is associated with:

- Remedial works required to the cracking that was identified on the pipework during the painting project at R2.
- Extra engineering scope required for the Fuel Gas Replacement project.
- Unplanned work to repair failing paintwork on the station pipework at R1.

In 2019, the underspend variance is associated with efficient and effective project delivery on the R4 painting project following the lessons learned from the R2 painting project.

61.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 110
2021 Planned – Non-Recurring Capital Expenditures – New/Replacement Tools and Equipment

On page 110 of the Amended Application, PNG states:

> These costs pertain to the purchase of a compressor pumpdown to reduce blowdown volumes…The pumpdown compressor reduces GHG emissions by removing volume of gas from the section to be blown down to the other side of a block valve. Therefore more gas is retained inside the piping system.

61.1 Please elaborate on the impact the purchase of a pumpdown compressor will have on PNG's annual unaccounted for gas estimates, if any.

Response:

The use of a compressor to evacuate and conserve the pressurized natural gas in a section of transmission pipe, rather than vent the gas to atmosphere, will not affect PNG's annual unaccounted for gas estimate. PNG currently estimates the quantity of natural gas evacuated to atmosphere during "blow downs" based on the physical dimensions of the evacuated section of pipe and the operating pressure. This quantity is identified as a component of company use gas and is therefore not reflected in the unaccounted for gas estimate.

62.0 Reference RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 111.
2021 Planned – Non-Recurring Capital Expenditures – Information & Data Management Systems – Synergi Gas

On page 111 of the Amended Application, PNG states:

> The remainder of the provision in this category for 2021 is to replace or supplement the existing modelling system with Synergi Gas (or similar) ($128,000). PNG's current hydraulic modelling system is aged and seen to be limited in its efficiency and use for future interfacing with PNG's other system such as GIS and advanced and more completely attributed digital system maps.

62.1 Please discuss the alternatives to current modelling system that are being considered and the pros and cons of each.

Response:

PNG's current alternatives analysis work to date has been limited to maintaining status quo with Gregg Engineering's WinFlow software or replacing and/or supplementing with another system used industry wide such as DNVGL's Synergi Gas.

Synergi Gas is used extensively throughout the pipeline industry and to PNG's present understanding has cornered the market for pipeline distribution systems, and to a lesser extent, transmission systems. PNG does not currently know of other significant competitors but more fulsome research for the purposes of alternatives analysis will be conducted as part of the proposed project. It is known that Gregg Engineering does have additional service offerings.

As discussed in the preamble, the current PNG modelling software has significant limitations in its ability to interface with PNG's GIS system, other PNG online operational management platforms, and is very inefficient from a user interface and maintenance perspective. Furthermore, it is seen as very limited in its applicability for daily use with distribution systems due to the volume and frequency of change. Synergi Gas is seen to be a valuable alternative and is regarded as such industry wide.

62.2 Please discuss the modelling system favoured by PNG's industry peers.

Response:

It is PNG's current understanding DNVGL's Synergi Gas is the leading modelling system of use with industry peers. There is known to be some divergence from this as it applies to relatively linear transmission systems that are subject to only infrequent design change and that incorporate compression operations. However, this requires further assessment and confirmation and will include the canvasing of other Canadian Gas Association (CGA) operators.

62.3 Please discuss the risks with maintaining PNG's existing modelling system, the age of the current system and its estimated useful life.

Response:

The main risks associated with maintaining the exclusive use of PNG's existing modelling software is that it becomes increasingly less maintained from a system change perspective given the inefficiency and near inability of its use in dealing with regular and frequent change in the absence of significantly greater resources (head count) to manage its processes and interfaces. As the PNG models fall behind the progressive improvement in accuracy and precision afforded by GIS and near real-time digital system maps, PNG runs appreciable risk of model output error that results in an inability to serve a new connection or that a new connection results in a system outage elsewhere due to unaccounted for pressure and/or volume considerations and limitations. This is of most notable risk with the projected future growth of the PNG-West system as it pertains to industrial and large commercial loads.

The existing Gregg Engineering WinFlow software has been in application at PNG for approximately 20 years and has seen limited change from a platform perspective. The system continues to be supported by Gregg Engineering, but it has been noted that they now have a number of other modelling and simulation service offerings that more completely address things such as system dynamism, change, and complexity. It is presently unknown the estimated life of the existing system from a support and offering perspective. In its current state it is seen as being at end of life for PNG without significant upgrade, supplementation, or replacement.

62.3.1 Please provide the expected cost savings PNG will realize as a result of this system.

Response:

Although PNG expects to realize cost savings through efficiency improvements as a result of upgrading its existing system, these cannot yet be quantified. Of greater importance is the potential cost avoidance opportunity that comes with ensuring that the PNG systems are being represented in as accurate and up to date fashion as possible, thereby helping to avoid costly error associated with unaccounted for change and inherent system limitations. Such risks could have very wide ranging cost implications.

63.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 111
2021 Planned – Non-Recurring Capital Expenditures – Piping Modification for Gas Blowdown Reduction

On page 111 of the Amended Application, PNG states:

> In order to reduce PNG emissions during blowdowns for maintenance work, PNG is proposing to make piping modifications to allow a pumpdown compressor to be used.

63.1 Please clarify the scope of piping modifications proposed in this capital expenditure activity, including the number of individual piping modifications that are forecasted to be completed in this test year.

Response:

The exact nature of the piping modifications and locations will need to be further developed during detailed Engineering and Design. Each valve location may require a different modification based on the extra valves and connections at that site. The modification required will require a hook up point on each side of the block valve. The current common 4" Blowdown is of a size and connection style that will not support a pump down compressor. But some sites will have extra smaller valve locations that can be used and others may not. The exact sections that get the modifications will also need to be reviewed from an engineering cost benefit analysis. Each section is of a different length and potential frequency, and have unique access issues. Therefore, a benefit of potential reduction vs. cost will need to be performed for each section and then analyzed for the best GHG reduction per dollar. Due to the above an exact quantity of modifications cannot be determined until further analysis is done.

64.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, p. 112
2021 Planned – Non-Recurring Capital Expenditures – High Voltage Alternating Current Mitigation

On page 112 of the Amended Application PNG states:

> For 2020, PNG-West has indicated it will be conducting the first phase of a project to mitigate the effects of the induced AC on the 10" pipeline that feeds Kitimat…estimated 2021 costs of $63,000 will be for implementation…
>
> PNG-West will also be conducting phase 1 of a project to mitigate the effects of the induced AC voltage on the 10" line that comes across the Telkwa Pass. This phase of the project has estimated costs of $100,000 for the design and procurement of the long lead items in anticipation of installation in 2022.

64.1 Please clarify the overall schedule for both the Kitimat and Telkwa Pass induced AC mitigation projects and the scopes of work forecasted to be completed in 2020.

Response:

Kitimat Projects

The Kitimat AC mitigation project is actually two separate projects in the region:

The first project is associated with the introduction of new high voltage lines that will feed the new LNG Canada site and will run parallel to PNG's pipeline. The project is scheduled to be completed in 2020. Please see the response to Question 54.1 for additional information and scope.

The second Kitimat project is on a separate section of PNG's pipeline system and is being implemented to mitigate the induced AC from the BC Hydro lines that run between Terrace and Kitimat and parallel the pipeline.

For 2020 the project scope for this project will be:

- Development and finalization of the grounding design to deal with anticipated induced voltage, including any necessary site visits.
- Procurement of necessary long lead items – grounding rods and AC decoupler.
- Securing necessary land permits and authorizations.

For 2021 the project scope will be:

- Procurement of the remaining necessary materials – including wiring and other materials necessary for creating grounding system.
- Installation of the equipment at the site, including necessary attachment to the pipeline system.

Telkwa Project

In 2021, the project scope will be:

- Development and finalization of the grounding design to deal with anticipated induced voltage, including any necessary site visits.
- Procurement of necessary long lead items – grounding rods and AC decoupler.
- Securing necessary land permits and authorizations.

In 2022, the project scope will be:

- Procurement of the remaining necessary materials – including wiring and other materials necessary for creating grounding system.
- Installation of the equipment at the site, including necessary attachment to the pipeline system.

64.1.1 If the project schedules extend beyond 2020, please confirm the expected Capital Expenditures and scopes of work for each project in future years.

Response:

Please see the table that follows.

Year of Spend / Project	Kitimat – Terrace Pipeline	Telkwa Pass Pipeline
2021	$95,231 for construction activities	$67,291 for design and procurement of long lead items
2022	$nil	$97,136 for construction activities

65.0 Reference: RATE BASE
Exhibit B-2, Section 2.13.1.1.2, pp. 112 and 113
2021 Planned – Non-Recurring Capital Expenditures – Port Edward Storage Bottle Removal and Methanex Lateral at Kitimat River Crossing Repair

On page 112 of the Amended Application, PNG states:

> This initial phase consists of upfront engineering and permitting activities in order to execute the project in 2022

On page 113 of the Amended Application, PNG states, "Detailed design, permitting, and execution would be proposed for completion in future years."

65.1 Please confirm the total project costs to complete this multi-year activity by year.

Response:

The projected costs for 2021 are aligned with the budget of $156,806. Due to the presumed complexity of the proposed project, significantly greater amounts of scope definition, risk assessment, and general project development work will be required through 2021 in order to define the total project cost. This acknowledgement was foundational in PNG's decision to propose associated field execution (construction) in 2022. The project is not proposed to extend beyond 2022.

66.0 Reference CAPITAL STRUCTURE AND RETURN ON CAPITAL
Exhibit B-2, Section 2.14.2, p. 118
Credit Rating

On page 118 of the Amended Application, PNG states:

> For the purposes of this Application for both Test Year 2020 and Test Year 2021, PNG-West has used the Decision 2019 approved rate of return on common equity (ROE) of 9.50% and common equity thickness of 46.50 % following the issuance of the Stage 2 GCOC Decision in 2014 and the Decision on the Fortis BC Energy Inc.'s (the Benchmark Utility) Application for its Common Equity Component and Return on Equity for 2016.

66.1 Please provide PNG's current credit rating, and comment on any changes in rating over the last five years.

Response:

PNG's credit rating from DBRS is BBB(low). There have been no changes in rating over the last five years.

66.2 Please provide PNG's credit rating reports for 2018 and 2019. Please file confidentially, as necessary.

Response:

Copies of PNG's 2018 and 2019 credit rating reports have been submitted on a confidential basis along with the responses to BCUC Confidential IR No. 1.

67.0 Reference **CAPITAL STRUCTURE AND RETURN ON CAPITAL**
Exhibit B-2, Section 2.9, p. 78; Section 2.14, p. 116; Section 3.2.1.4, p. 142; Section 3.2.2.4, pp. 149-150
Financing Costs

Table 42 of page 116 includes PNG's capital structure and Table 42 includes interest expense.

67.1 Please provide a table with the approved and decision interest rate and debt balance for short term and long-term debt for each year between 2015 and 2019 and the forecast for 2020 and 2021.

Response:

Please see the table that follows.

$000's							
Item	Test Year	Test Year	Decision				
	2021	2020	2019	2018	2017	2016	2015
Short-term Debt							
Interest Rate	4.33%	4.42%	4.93%	4.54%	3.62%	3.73%	4.40%
Debt Balance	9,782	8,868	8,215	7,247	8,393	7,191	7,131
Long-term Debt							
Interest Rate	5.04%	5.21%	5.50%	5.89%	5.64%	5.62%	6.04%
Debt Balance	78,402	72,886	68,988	66,702	64,166	65,239	66,268

67.2 Please expand Table 41 to include the following information:

- Columns for Decision 2015 to 2018
- Rows for total short-term debt, long-term debt and return on common equity components of cost of service

Response:

Please see the table that follows.

	$000's															
Expense Item	Test Year 2021	2021 to 2020 Change $	2021 to 2020 Change %	Test Year 2020	2020 to 2019 Change $	2020 to 2019 Change %	Decision 2019	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015	Decision 2018	Decision 2017	Decision 2016	Decision 2015
Short-term Debt																
Balance ($000's)	9,782	914	10.3%	8,868	653	8.0%	8,215	(4,840)	(4,056)	2,152	(4,219)	2,230	7,247	8,393	7,191	7,131
Proportion (%)	5.93%	0.13%	2.27%	5.80%	0.11%	1.94%	5.69%	(3.41)%	(3.00)%	1.59%	(3.10)%	1.63%	5.24%	6.19%	5.31%	5.20%
Total Short Term Debt	9,782			8,868			8,215	(4,840)	(4,056)	2,152	(4,219)	2,230	7,247	8,393	7,191	7,131
Long-term Debt																
Balance ($000's)	78,402	5,516	7.6%	72,886	3,898	5.7%	68,988	56,209	51,272	49,066	57,604	63,330	66,702	64,166	65,239	66,268
Proportion (%)	47.57%	(0.13)%	(0.28)%	47.70%	(0.11)%	(0.23)%	47.81%	39.58%	37.95%	36.22%	42.37%	46.36%	48.26%	47.31%	48.19%	48.30%
Total Long-Term Debt	78,402			72,886			68,988	56,209	51,272	49,066	57,604	63,330	66,702	64,166	65,239	66,268
Preferred Shares																
Balance ($000's)	-	-	0.0%	-	-	0.0%	-	-	-	-	-	-	-	-	-	-
Proportion (%)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Common Equity																
Balance ($000's)	76,646	5,589	7.9%	71,057	3,956	5.9%	67,101	90,659	87,885	84,258	82,573	71,037	64,273	63,065	62,953	63,796
Proportion (%)	46.50%	0.00%	0.00%	46.50%	0.00%	0.00%	46.50%	63.83%	65.05%	62.19%	60.73%	52.00%	46.50%	46.50%	46.50%	46.50%
Return on Common Equity (%)	9.50%			9.50%			9.50%	7.54%	6.99%	7.45%	6.63%	7.61%	9.50%	9.50%	9.50%	9.50%
Return on Common Equity	7,281			6,750			6,375	6,836	6,143	6,277	5,475	5,406	6,106	5,991	5,981	6,061
Total Capitalization ($000's)	**164,831**	**12,019**	**7.3%**	**152,811**	**8,508**	**5.6%**	**144,304**	**142,029**	**135,102**	**135,476**	**135,959**	**136,598**	**138,222**	**135,624**	**135,383**	**137,195**

67.3 Please provide the actual short-term debt balance as a component of total debt for each year between 2015 and 2019.

Response:

Please see the table that follows.

$000's					
Item	**Actual**				
	2019	**2018**	**2017**	**2016**	**2015**
Short-Term Debt Balance	(4,840)	(4,056)	2,152	(4,219)	2,230
(% of Total Debt)	-9.4%	-8.6%	4.2%	-7.9%	3.4%
Long-term Debt Balance	56,209	51,272	49,066	57,604	63,330
(% of Total Debt)	109.4%	108.6%	95.8%	107.9%	96.6%
Total Debt Balance	51,369	47,216	51,217	53,385	65,560

67.3.1 With reference to the information provided in the preceding IR response, please elaborate on why 5 percent of rate base is appropriate for the short-term debt component of the capital structure.

Response:

PNG notes that its actual capital structure has historically [for the last 20 years] included more common equity than the amount of common equity approved by the BCUC for the purpose of calculating PNG's customer rates. PNG has carried the additional common equity ("excess equity") in order to avoid a downgrade of its long-term debt rating below investment grade. As submitted by PNG in numerous hearings over this period of time, a downgrade of PNG's long-term debt rating would have been adverse to its customers. The adverse impacts of a credit rating downgrade include higher interest expense for all new debt arrangements, whether long-term or short-term, as well as additional costs for the provision of security to PNG's suppliers, particularly natural gas producers.

As a result of PNG having excess common equity in its actual capital structure, both actual long-term debt and short-term debt components have been lower than the deemed levels of short and long-term debt approved for rate setting purposes. PNG's position on the appropriate level of short-term debt approved in rate base for the purpose of setting rates cannot be set relative to actual short-term debt levels, when the level of common equity approved for PNG's deemed capital structure is not also set relative to actual common equity levels.

Given the lack of any logical basis for setting the approved level of short-term debt relative to actual levels of short-term debt under PNG's historical circumstances, PNG has relied on the principal of asset matching, as outlined in its Amended Application at page 116, lines 6-9, for setting the appropriate level of short-term debt in its deemed capital structure. In particular, PNG believes that the deemed level of short-term debt should be set at a level which is sufficient to cover its working capital requirements.

On page 117 of the Amended Application PNG submits that:

> Since PNG was unable to locate a source of independent forecasts of short-term debt interest rates for 2021, it has used the 2020 forecast for that year as well.

67.4 With consideration of any changing economic conditions since the Amended Application was filed, please provide any updates to the forecast short-term and long-term interest rates and the resulting impact on the 2020 and 2021 cost of service that is currently available.

Response:

Despite the rate reductions in underlying government debt instruments, the underlying rates for corporate instruments have not moved significantly. Financial institutions have significantly increased credit spread requirements and standby charges for debt that have more than offset the reductions in prime rates. PNG is exposed to these impacts for both any new financing that may be required for RECAP, and also at the renewal of the 18-month operating facility which will next be required in May 2021. PNG relies on the short term and long term deferral accounts to capture the differences in the actual and forecast debt rates rather than forecasting corporate credit spreads and changes in other bank charges.

As noted in page 116 of the Amended Application, the forecast of the underlying prime rate for operating line borrowings in both Test Year 2020 and Test Year 2021 was based on the forecast decrease in the average 90-day treasury bill rate for 2020 relative to the forecast 90-day treasury bill rate from Decision 2019 which is then added to the forecast 2019 Decision prime rate. PNG based the forecast 90-day treasury bill rate for 2020 from BMO's published forecast dated November 22, 2019. With the changing economic conditions, BMO has published a forecast dated March 27, 2020 which shows that the forecast 90-day treasury bill rate for 2020 has declined from 1.6625% to 0.4875%. BMO's publication also includes a forecast for 2021 which is 0.20%. BMO's March 2020 publication has been reproduced on the pages that follow this response.

Use of the updated forecast would reduce PNG-West's forecast 2020 and 2021 short term and long term debt interest rates as follows:

- In Test Year 2020, PNG-West's forecast average short-term interest rate would decline by 118 basis points to 3.24% and PNG-West's forecast average long-term interest rate would decline by 50 basis points to 4.71%.

- In Test Year 2021, PNG-West's forecast average short-term interest rate would decline by 146 basis points to 2.87% and PNG-West's forecast average long-term interest rate would decline by 57 basis points to 4.47%.

The resulting impact on the 2020 and 2021 cost of service from the updated 90 day treasury bill rate on 2020 and 2021 short term debt costs would result in a decrease in costs of $105,000 and $143,000, respectively.

The resulting impact on the 2020 and 2021 cost of service from the updated 90 day treasury bill rate on 2020 and 2021 long term debt costs would result in a decrease in costs of $364,000 and $447,000, respectively.

These impacts are illustrated in the table that follows.

$000's		
Item	**Test Year 2021**	**Test Year 2020**
Short-term Debt		
Debt Balance	9,782	8,868
Interest Rate - Amended Application	4.33%	4.42%
Interest rate - Using Updated 90-Day Treasury Bill Forecast	2.87%	3.24%
Difference in Average Short-Term Interest rate	-1.46%	-1.18%
Impact on Short-Term Interest Costs	(143)	(105)
Long-term Debt		
Debt Balance	78,402	72,886
Interest Rate - Amended Application	5.04%	5.21%
Interest rate - Using Updated 90-Day Treasury Bill Forecast	4.47%	4.71%
Difference in Average Long-Term Interest rate	-0.57%	-0.50%
Impact on Short-Term Interest Costs	(447)	(364)

PNG already has established both short term and long term interest rate deferral accounts in place to capture variances in short term and long term 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 proposes to rely on these deferral accounts to capture any differences in financing costs for Test Years 2020 and 2021.

Canadian Economic Outlook | Our key forecasts for the Canadian economy — March 27, 2020

Canadian Economic Outlook for Mar. 27, 2020

A Publication of BMO Capital Markets Economic Research • Douglas Porter, CFA, Chief Economist, BMO Financial Group

		2019				2020				2021							
		Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	2018	2019	2020	2021
Production	q/q % chng : a.r.																
Real GDP (chain-weighted)		1.0	3.4	1.1	0.3	-6.5	-25.0	30.0	4.1	2.2	2.1	1.9	1.8	2.0	1.6	-3.0	3.5
Final Sales		-1.0	5.0	3.0	-0.1	-6.6	-23.4	29.2	3.3	2.2	2.1	1.9	1.8	2.3	1.5	-2.6	3.4
Final Domestic Demand		3.1	0.1	3.1	0.7	-5.0	-23.1	28.4	3.1	2.2	2.0	1.8	1.7	2.1	1.2	-2.3	3.3
Consumer Spending		2.4	0.4	2.0	2.0	-8.8	-32.4	42.2	3.4	2.2	1.9	1.7	1.4	2.2	1.6	-4.2	3.8
Durables		4.8	-2.6	1.4	-0.2	-7.0	-40.0	40.0	5.0	2.0	1.8	1.4	1.5	1.7	0.6	-6.6	3.0
Nondurables		1.2	-0.2	1.8	1.1	-3.0	-10.0	10.0	1.5	2.5	1.7	1.5	1.5	1.8	1.0	-1.0	2.0
Services		2.4	1.0	2.3	3.4	-12.0	-40.0	58.5	4.0	2.2	2.1	1.8	1.4	2.5	2.1	-5.5	4.5
Government Spending		2.8	0.7	2.1	0.5	1.5	4.5	6.8	1.6	2.4	2.2	2.1	2.0	3.4	1.6	2.6	2.8
Business Investment		18.3	-7.7	5.6	-6.3	-5.0	-40.0	25.0	5.0	2.5	2.5	2.0	2.0	1.4	0.0	-8.3	1.9
Non-residential Construction		4.4	4.3	11.2	-1.7	-5.0	-40.0	25.0	5.0	2.5	2.5	2.0	2.0	-0.6	0.9	-6.2	1.9
Machinery and Equipment		42.7	-23.2	-2.6	-13.5	-5.0	-40.0	25.0	5.0	2.5	2.5	2.0	2.0	4.7	-1.4	-11.7	1.9
Residential Construction		-3.1	6.4	13.0	1.1	0.0	-30.0	20.0	5.5	1.0	1.5	1.7	2.0	-1.6	-0.6	-1.9	1.9
Exports		-4.0	10.6	-0.6	-5.1	-7.9	-7.7	8.3	6.0	2.1	2.3	2.4	2.3	3.1	1.2	-2.6	3.0
Imports		8.3	-4.1	-0.2	-2.5	-2.9	-7.7	8.2	5.3	2.1	2.0	2.0	1.9	2.6	0.3	-1.7	2.7
Inventory Change	2012$ blns : a.r.	24.1	17.0	7.1	10.5	10.6	2.2	6.5	10.7	10.7	10.7	10.8	10.8	13.0	14.7	7.5	10.8
Contrib. to GDP Growth	ppts : a.r.	1.9	-1.4	-1.8	0.6	0.1	-1.6	0.8	0.8	0.0	0.0	0.0	0.0	-0.3	0.1	-0.5	0.1
Net Exports	2012$ blns : a.r.	-12.7	11.1	10.3	5.7	-3.0	-2.9	-2.8	-1.7	-1.7	-1.2	-0.6	0.0	-2.4	3.6	-2.6	-0.9
Contrib. to GDP Growth	ppts : a.r.	-4.1	4.8	-0.1	-0.8	-1.5	0.2	-0.3	0.0	-0.1	0.0	0.1	0.1	0.1	0.3	-0.2	0.0
Nominal GDP	$ blns : a.r.	2,260	2,305	2,312	2,338	2,299	2,107	2,259	2,296	2,321	2,345	2,370	2,393	2,224	2,304	2,240	2,357
Growth	q/q % chng : a.r.	5.7	8.2	1.3	4.5	-6.4	-29.5	32.1	6.6	4.4	4.3	4.3	3.9	3.9	3.6	-2.8	5.2
Real GDP	y/y % chng	1.5	2.0	1.6	1.5	-0.5	-8.2	-2.2	-1.3	0.9	9.0	2.5	2.0				
Inflation	q/q % chng : a.r.																
GDP Price Index		4.5	4.5	0.4	4.1	0.1	-5.9	1.6	2.5	2.2	2.2	2.4	2.0	1.8	1.9	0.3	1.6
CPI All Items		1.7	3.3	1.6	1.7	1.3	-3.2	3.4	2.1	2.1	2.0	2.0	2.1	2.3	1.9	1.0	1.9
Ex. Food and Energy		1.9	2.7	2.1	1.1	1.6	2.1	2.7	1.6	2.1	1.9	2.0	2.1	1.9	2.1	1.9	2.0
Food Prices		3.9	2.7	4.0	2.9	1.3	1.3	1.8	2.1	2.0	2.1	1.8	2.1	1.8	3.4	2.1	1.9
Energy Prices		-6.1	15.8	-7.8	5.0	-5.7	-56.9	16.7	7.4	3.5	2.8	2.4	2.0	7.5	-2.9	-12.9	-0.5
Services		1.9	3.8	3.8	-1.3	1.7	2.2	2.2	1.5	1.9	2.4	2.3	1.5	2.5	2.5	1.6	2.0
CPI All Items	y/y % chng	1.6	2.1	1.9	2.1	2.0	0.3	0.8	0.9	1.1	2.4	2.0	2.0				
CPIX8	y/y % chng	1.6	1.9	1.9	1.8	1.8	1.6	1.5	1.5	1.4	1.7	1.7	2.1	1.4	1.8	1.6	1.7
New Core CPIs	y/y % chng : avg.	1.9	2.0	2.0	2.1	2.1	1.6	1.5	1.5	1.4	1.7	1.8	2.1	1.9	2.0	1.6	1.7
Financial	% : quarterly avg.																
Overnight Rate		1.75	1.75	1.75	1.75	1.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	1.44	1.75	0.50	0.25
3-Month T-Bill		1.65	1.67	1.64	1.66	1.30	0.25	0.20	0.20	0.20	0.20	0.20	0.20	1.37	1.65	0.50	0.20
90-Day BAs		2.14	2.00	1.96	1.99	1.85	1.00	0.75	0.60	0.55	0.55	0.55	0.55	1.89	2.02	1.05	0.55
10-Year Bond Yield		1.86	1.62	1.36	1.52	1.20	0.65	0.70	0.80	0.90	1.05	1.20	1.35	2.28	1.59	0.85	1.15
10-Year BBB Corporate Spread	ppts	2.20	2.01	1.94	1.93	2.00	3.30	2.70	2.40	2.30	2.30	2.30	2.30	1.85	2.02	2.60	2.30
90 Day Canada/U.S. Spread	bps	-79	-68	-38	5	17	8	3	3	3	3	3	3	-60	-45	7	3
10 Year Canada/U.S. Spread	bps	-80	-72	-43	-28	-18	-5	-5	-4	-4	-4	-3	-3	-63	-56	-8	-3
Foreign Trade	$ blns : a.r.																
Current Account Balance		-69.4	-33.7	-43.5	-35.0	-54.3	-74.5	-72.1	-67.3	-67.6	-66.0	-63.6	-62.6	-55.5	-45.4	-67.0	-65.0
Share of GDP		-3.1	-1.5	-1.9	-1.5	-2.4	-3.5	-3.2	-2.9	-2.9	-2.8	-2.7	-2.6	-2.5	-2.0	-3.0	-2.8
Merchandise Balance		-36.1	-7.6	-16.6	-12.6	-31.9	-53.2	-51.3	-47.6	-46.9	-45.5	-43.2	-42.2	-22.1	-18.2	-46.0	-44.4
Non-Merchandise Balance		-33.2	-26.1	-26.9	-22.4	-22.4	-21.2	-20.7	-19.7	-20.7	-20.5	-20.5	-20.4	-33.4	-27.2	-21.0	-20.5
US$	US¢/C$: qtr. avg.	75.2	74.8	75.7	75.8	74.3	68.4	69.8	71.0	71.9	72.5	73.2	73.8	77.2	75.4	70.9	72.8
	C$/US$: qtr. avg.	1.329	1.338	1.321	1.320	1.346	1.462	1.433	1.408	1.392	1.379	1.367	1.354	1.296	1.327	1.412	1.373
Yen	¥/C$: qtr. avg.	82.9	82.2	81.3	82.4	80.8	69.0	72.2	75.4	77.8	80.0	82.2	84.4	85.2	82.2	74.4	81.1
Euro	C$/€ : qtr. avg.	1.51	1.50	1.47	1.46	1.48	1.57	1.56	1.54	1.54	1.53	1.52	1.51	1.53	1.49	1.54	1.52
Corp. Profits Before Tax	y/y % chng	-13.9	-9.0	-17.9	2.4	1.7	-28.8	-18.6	-1.5	5.1	39.7	32.9	11.8	4.0	-10.2	-12.2	20.8
Corp. Profits After Tax	y/y % chng	-1.1	1.8	-5.6	0.0	1.1	-26.0	-19.7	-1.5	5.1	39.7	32.9	11.8	6.6	-1.3	-11.8	20.8
Personal Income	y/y % chng	4.1	5.2	4.9	4.6	2.3	-5.1	-0.8	-0.4	1.8	8.9	4.7	4.1	4.3	4.7	-1.0	4.8
Real Disposable Income	y/y % chng	2.0	2.7	3.1	2.8	0.4	-5.3	-1.2	-0.9	1.2	7.0	2.6	2.1	2.0	2.6	-1.7	3.2
Savings Rate	% : quarterly avg.	2.1	3.0	2.8	3.0	3.3	6.7	3.8	4.0	4.0	4.1	4.4	4.6	1.8	2.7	4.4	4.3
Other Indicators	quarterly avg. (000s and mlns are a.r.)																
Unemployment Rate	percent	5.8	5.6	5.6	5.7	6.4	9.3	8.4	8.0	7.6	7.2	6.8	6.5	5.8	5.7	8.0	7.0
Housing Starts	000s	187	224	223	202	208	160	190	203	217	222	227	232	214	209	190	225
Existing Home Sales	y/y % chng	-4.2	5.5	9.7	15.1	15.9	-20.6	-7.6	-6.1	-4.4	31.1	5.2	2.0	-10.8	6.5	-5.0	7.0
MLS Home Price Index	y/y % chng	-0.5	-0.3	1.2	3.3	5.3	4.5	3.1	2.0	1.2	1.2	2.8	3.5	2.7	0.7	4.0	2.0
Motor Vehicle Sales	mlns	2.00	1.93	1.98	1.93	1.93	1.65	1.80	1.81	1.85	1.89	1.91	1.95	2.04	1.96	1.80	1.90
Employment Growth	q/q % chng : a.r.	3.0	2.6	1.1	0.5	-2.2	-12.4	5.2	2.7	2.5	2.4	2.4	2.2	1.3	2.1	-1.8	1.9
Industrial Production	q/q % chng : a.r.	-3.8	4.4	-5.1	-2.4	1.4	-9.1	1.1	2.1	2.5	2.4	1.9	1.6	3.1	-1.1	-2.0	1.3
Federal Budget Balance	% of FY GDP													-0.6	-1.2	-1.2	-1.0

Shaded values represent forecasts

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On page 78 of the Amended Application PNG states:

> The short term interest deferral account records the impact of differences between the underlying customer security deposit and short term operating line interest rates. The long term interest deferral account records the impact of differences between the underlying long term forecast interest rates and actual interest rates.

On pages 142 and 149 of the Amended Application, PNG discusses the variance between actual and decision interest expense on short term debt for 2018 and 2019.

Further, on pages 142 and 150 of the Amended Application, PNG discusses the variances between actual and decision interest on long term debt for 2018 and 2019. In both years the interest expense was lower than forecast, primarily due to PNG-West having less long-term debt and more common equity in its actual capital structure than forecast.

67.5 Please explain the measures PNG is taking to reduce the proportion of common equity from 63.83 percent in 2019 to the deemed equity of 46.50 percent in 2020 and 2021.

Response:

The 46.50% proportion of common equity shown for 2020 and 2021 reflects the level of common equity approved by the BCUC for PNG's deemed capital structure in accordance with Order G-47-14. As noted in the response to Question 67.3.1 above, PNG has for many years maintained an actual common equity component that exceeds the approved 46.5% in order to maintain an investment grade credit rating on its long-term debt. As and when PNG's risk profile supports the reduction of its capitalization with common equity without endangering its investment grade credit rating, PNG will be taking the very straightforward steps to achieve this result: (i) incur additional debt; and, (ii) issue a dividend to its shareholder.

67.6 Please discuss how PNG having a greater common equity component in its actual capital structure as compared to its deemed structure impacts the shareholder and ratepayers. Include discussion on both the return on equity and interest expense.

Response:

Having a greater common equity component in its actual capital structure as compared to its deemed structure is adverse to its shareholder and beneficial to PNG's ratepayers. As noted in the response to Question 67.3.1, if PNG historically had not maintained the greater common equity component on an actual basis, the debt rating agency indicated it would have downgraded PNG's long-term debt rating below investment grade. In turn, this would have resulted in higher borrowing rates for PNG as well as the costs of providing security to suppliers such as natural gas producers.

By having common equity in its actual capital structure that is in excess of the equity capitalization of rate base, PNG's shareholder effectively earns an after-tax interest rate on the excess equity. For example, if PNG has $20 million of excess equity, that additional equity will be used by PNG to reduce the amount of actual debt carried by PNG relative to the amount the BCUC has approved for the capitalization of rate base. If the $20 million of debt that PNG is able to avoid borrowing in this example has an interest rate of 4.0% (this is slightly higher than PNG's revolving line borrowing costs), PNG's shareholder effectively earns 2.92% after providing for a 27% tax rate on these funds which are earned as taxable income. This return on common equity is significantly below the 9.50% the BCUC has determined is a fair and reasonable return on common equity for PNG.

K. PROPOSED RATE CHANGES

68.0 Reference PROPOSED RATE CHANGES
Exhibit B-2, Section 2.15.3, p. 120
RSAM Rate Rider

On page 120 PNG provides rationale for the increase in forecast RSAM rate rider and states:

> The increase in the forecast RSAM debit rate rider reflects the increases in the 2018 and 2019 RSAM pools as a result of warmer weather experienced to date during the past two years, the forecast lower use per account, as well as the recovery of the historical RSAM balances through the current rider.

68.1 Please explain whether the RSAM Rate Rider tracks variances of revenue in use per account as well as variances in number of customers. If not, why not.

Response:

The RSAM deferral account tracks the variances in margin between the actual and forecast use per account for residential and small commercial customers. The RSAM rate rider is the mechanism to either refund or recover the RSAM balances from the respective customer rate classes over a two-year period. The RSAM deferral account does not track variances in number of customers. This mechanism was established and approved by the BCUC Order G-14-03 and was structured in the same manner as BC Gas Utility Ltd.'s (now FortisBC Energy Inc.) RSAM that was approved by the BCUC in 1994 under Order G-59-94. The primary intent of the RSAM is to capture the variances in use per account due to weather.

69.0 Reference PROPOSED RATE CHANGES
Exhibit B-2, Section 2.15.3, p. 120
Rates are Just and Reasonable

On page 120 of the Amended Application PNG states:

> PNG-West's rates are competitive with other energy sources and thereby provide a reasonable probability of preventing declining recovery of margin due to customers converting to alternative energy sources or reducing gas consumption;

69.1 Please elaborate on the market comparators and/or peers that were used to determine that PNG-West's rates were competitive and discuss why these comparators were selected.

Response:

PNG submits that electricity is the primary market comparator as residential and commercial customers would normally make a choice for space and water heating systems and certain appliances primarily between natural gas or electricity. PNG addresses the competitiveness of natural gas in the 2019 Consolidated Resource Plan for PNG-West and PNG(NE) presently under review by the BCUC. PNG also notes that it has provided a comparison of its natural gas rates and electricity rates for residential and small commercial customers under Section 2.15.6 of the Amended Application to illustrate and support its determination that its rates are competitive.

70.0 Reference PROPOSED RATE CHANGES
Exhibit B-2, Section 2.15.6, p. 121; Tab 6, p. 5
Bill Comparison

On page 5 of Tab 6 in the Amended Application, PNG presents the comparison of the projected annual gas bills for residential and small commercial customers using rates effective October 1, 2019 and rates proposed effective January 1, 2020.

On page 121 of the Amended Application, PNG states:

> The bill comparison focuses on the delivery rate increase that is required to recover the forecast 2020 and 2021 revenue deficiencies (including the Company use gas cost). PNG-West has also included the indicative gas supply cost related rates for January 1, 2020 which are subject to the BCUC's review as part of PNG-West's fourth quarter 2019 gas cost report.

70.1 Please discuss whether PNG considers that the bill impact ranging between 11 and 13 percent for the residential and small commercial customers constitutes rate shock. If not, please discuss why not. If yes, please discuss any measures undertaken by PNG to mitigate this.

Response:

In this Amended Application, PNG is seeking a delivery rate increase that averages approximately 2% for its customers. However, due to the increase in the RSAM rate rider for Test Year 2020, from a credit rider of $0.327/GJ to a debit rider of $1.175/GJ, residential and small commercial customers will see a bundled overall rate increase of 11% and 12.4%. This increase in the RSAM rate rider is primarily due to much warmer weather conditions experienced in both 2018 and 2019. Therefore, PNG collected lower than forecast margin from these two customer classes in both 2018 and 2019, and through the RSAM, PNG will collect these variances from these customer classes in 2020 and 2021.

PNG is very cognizant that the overall bundled rate increases may be significant and may constitute rate shock for some customers, in particular the low income households. For Test Year 2020, the proposed overall rate increase would result in bill increases of $11.37 per month for the average residential customer and $47.36 per month for the average small commercial customer, of which 75% to 79% is due to the increase in the RSAM rate rider. PNG also notes that the opposite effect may take place. For example, in 2018 the RSAM rate rider went from $1.656/GJ to $0.252/GJ, resulting in a significant decrease of $1.404/GJ in customer rates in 2018.

Over the years, PNG has made significant efforts to keep operating costs down and has delayed any non-critical work on its system while still providing safe and reliable service to its customers. However, it is critical that PNG address aging infrastructure concerns as well as ensure it is compliant with pipeline integrity codes, standards and regulations. In this Amended Application, PNG has proposed the drawdown of the Option Fee Payment deferral account as well as the deferral of a portion of Shared Corporate Services costs in order to maintain the delivery rate increase to customers to approximately 2%. PNG is hopeful that with the upcoming RECAP, it will have a greater ability to mitigate future rate increases to its customers.

70.2 Please provide the bill impact for any other PNG-West customer class that exceeds ten percent. Discuss how PNG will address concerns for the bill impacts that are greater than ten percent.

Response:

Please see the table below for the bill impact for the Small Commercial Transportation customer class. As this customer class is also subject to the change in the RSAM rate rider, the change in the overall bundled rate is greater than ten percent. Please also see the response to Question 70.1.

(PNG-West Division)

Bill Comparison
October 2019 to January 2020

Customer Classification	Annual Use	Permanent Rates Oct. 1, 2019 $ / GJ	Annual Bill Estimate $	Proposed Rates Jan. 1, 2020 $ / GJ	Annual Bill Estimate $	Annual Bill Difference $	%
Small Commercial Transportation:	1,256.0 GJ						
Monthly Fixed Charge @ 10.75 / mo.		0.239	300.00	0.239	300.00	n.a	
Delivery Charge		10.259	12,885.22	10.513	13,204.25	319.02	2.5%
GCVA Co. Use Rider		0.098	123.09	0.050	62.80	(60.29)	
RSAM Rider		(0.327)	(410.71)	1.175	1,475.79	1,886.50	
			12,897.60		15,042.84	2,145.23	16.6%
Gas Supply Charge		-	0.00	-	0.00	-	
GCVA Rider		-	0.00	-	0.00	-	
			0.00		0.00	-	0.0%
Carbon Tax		0.000	0.00	0.000	0.00	-	
		$10.269 /GJ	$12,897.60	$11.977 /GJ	$15,042.84	$2,145.23	16.6%

L. CAPITAL EXPENDITURE REPORTING – ACTUAL VS DECISION

71.0 Reference: CAPITAL EXPENDITURE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.1.1, p. 125
2018 Capital Expenditure Variance Analysis – Unspecified Mainline Repairs

On page 125 of the Amended Application, PNG states:

> In concert with asset and infrastructure additions on Ridley Island directly associated with the RIPET service request, a number of system integrity and otherwise betterment activities were realized as a result of synergies with the RIPET project…
>
> [Regarding Cathodic Protection Improvements] Improvement directly realized by existing pipeline system assets were attributed to a directly associated and apportioned amount of the overall CP system cost…
>
> [Regarding Distribution Pressure Pipeline System Improvements] Cost exclusively associated with existing DP system and customer service improvement were attributed to an associated betterment project…
>
> [Regarding High Pressure Pipeline System Improvements] Costs were incurred for existing high pressure asset system betterment associated with integrity risk reduction, asset longevity (remaining service life), and improved ability to respond to future load growth on Ridley Island…

71.1 With reference to variances between historic actual and decision costs for unspecified mainline repairs, please discuss any issues associated with the current forecast methodology and whether PNG has considered developing the forecast based on specific capital work that is expected to be undertaken or some other methodology.

Response:

In general, PNG does not believe there to be significant concern with the forecasting methodology for unspecified mainline repairs. As previously discussed in response to Question 48.2, PNG believes its methodology and approach that takes into account 5-year rolling averages, sources of upward scope and timeliness pressure, and non-routine or otherwise exceptional circumstances, is a reasonable approach to the forecasting and financial address of unknown project activities. It is noted here that the costs incurred as a result of the coincident RIPET project were very unique and unlikely to occur at any appreciable frequency for PNG in the future.

71.2 For each of the Ridley Island Cathodic Protection Improvements, Ridley Island Distribution Pressure Pipeline System Improvements and Ridley Island High Pressure Pipeline System Improvements, please discuss if these expenditures would have been required in the absence of the Ridley Island Propane Export Terminal project.

Response:

Cathodic Protection Improvements:

The cathodic protection improvements would have been required in the absence of the Ridley Island Propane Export Terminal (RIPET) project in order to optimize the remaining life of the existing pipeline system, to address known insufficiency of impressed current protection at various locations on the downstream ends of the existing system, to minimize accelerated rates of rectifier and anode bed depletion, and to mitigate ongoing corrosion issues found in a pipeline system originally installed in the early 1980's by a previous pipeline system owner and in the original absence of cathodic protection. Numerous recent instances of extensive corrosion had been found in the pipeline system in proximity to the Ridley Terminals operations and offices, resulting in more than one gas leak and challenging repair. Furthermore, with ongoing rail developments by the Prince Rupert Port Authority (PRPA) and the recent increase in requirements by both CN Rail and Transport Canada for pipelines paralleling and crossing rail infrastructure, significantly increased amounts of cased piping would be required in response. The cathodic improvement activities were in reaction to known concerns and ongoing improvement requirements, ensuring the pipeline system remained fit for operation for future expansion and service on Ridley Island. The coincidental activities and requirements of the RIPET project were able to be leveraged to minimize unplanned betterment costs by incurring the significant majority within the RIPET CIAC recovery.

Distribution Pressure Pipeline System Improvements:

Past and continuing development on Ridley Island, including extensive infilling atop the pre-existing pipeline system by Ridley Terminals, PRPA, and other island tenants, has resulted in areas with pipeline depth of cover greater than 30 feet and permanent structures constructed in close proximity to or atop existing DP pipelines. This was true for lengths of pipeline running through the Ridley Terminal coal bulk handling yard. Furthermore, areas of existing rail parallelism and crossing were known to be non-compliant with updated regulations. Ongoing developments on Ridley Island by CN, PRPA, and other island tenants were resulting in considerable upward pressure to react to known integrity concerns associated with the above. The coincidental activities and requirements of the RIPET project allowed for significant improvements, address of known integrity concerns, while allowing minimization of cost impacts to PNG ratepayers by covering the significant majority of associated costs within the RIPET CIAC recovery.

High Pressure Pipeline System Improvements:

In the presence of ongoing and known future industrial expansion plans on Ridley Island, PRPA created a designated utility corridor (water, gas, electric) through the main rail yard. This utility corridor location ensured as best possible that utilities would not be further impacted by island development. As a result, PNG was required to relocate its main HP pipeline. In concert with this relocation, PNG required specific improvements to the existing high-pressure pipeline system to be able to attract and

service new industrial customers – providing resiliency and reliability. This infrastructure is of critical important to ensuring existing customers enjoy opportunity for downward pressure on rates through industrial growth. Given the complexities on Ridley Island, both before and the result of RIPET, there are few opportunities to make necessary improvements. This is a result of coactivity constraints and significant constraints imposed by encroaching infrastructure and the quickening occupation of remaining available land in proximity to the pre-existing pipeline system. As a result, in order to remain relevant on Ridley Island for future expansion, PNG saw the need for HP system improvements and the justification in partial allocation to overall system betterment. These requirements would have been required in near future due to utility location consolidation efforts and in the absence of RIPET. Similar to other improvements discussed, there was significant associated cost avoidance through coincidental related needs of RIPET and the associated project CIAC recovery.

71.2.1 If yes, for each of the three projects identified in the preceding IR, please discuss how the capital expenditures provide benefit to PNG's overall transmission system and PNG's ratepayers.

Response:

PNG's existing customers have leveraged a significant opportunity to piggyback on the RIPET project, therefore receiving a large array of benefits for a fraction of the costs. Many of the benefits relating to the overall pipeline system and existing ratepayers are embedded in the response provided to Question 71.2 above, with the following summary providing additional information:

- Compliance with Codes, Standards and Regulations: PNG had identified compliance concerns with depth of cover on its pipeline system, particularly on the main artery on Ridley Island, which needed immediate attention for safe and reliable service. Importantly, PNG would have had to upgrade the line anyway (at existing ratepayers' expense) to address design requirements for CN rail infrastructure. For clarity, there are large existing customers that are served from this exact line that was upgraded. Thus, PNG existing ratepayers benefited from the improvement. The cost to address these concerns, independently, at a future time, would have been a significant cost to existing customers, which has been avoided through the synergies of the RIPET project.

- Obsolescence and Aging Infrastructure: As described above, the cathodic protection work was needed in order to optimize the remaining life of the existing pipeline system, to address known insufficiency of impressed current protection at various locations on the downstream ends of the existing system, to minimize accelerated rates of rectifier and anode bed depletion, and to mitigate ongoing corrosion issues found in a pipeline system originally installed in the early 1980's by a previous pipeline. In addition, PNG's existing customers are receiving a benefit to receive essentially a new trunk line on Ridley Island. There are large existing customers that are served from this line that benefited from this improvement.

- System Resiliency, Reliability and Network Optimization: As described above, PNG required specific improvements to the existing high-pressure pipeline system to be able to attract and service new industrial customers, while providing resiliency and reliability. This infrastructure upgrade is of critical important to ensuring existing customers enjoy opportunity for downward pressure on rates through industrial growth. The cost to provide these upgrades in the future would have been significantly higher and difficult to permit with PRPA given the synergies with the existing project.

- Environmental Benefits: PNG is cognizant of the environmental impacts of short-sighted planning in a location that has an industrial development plan, including the possibility of undertaking construction work in the exact same location.

- Utility Corridor: PNG was being asked by PRPA to move its infrastructure in a utility corridor, including allowance for water and proximity to the rail. Given PNG's land tenure, it is highly possible that PNG would have been required to pay for the re-alignment given that PNG's line is in PRPA federal lands. PNG was able to leverage the RIPET project to accommodate the relocation.

- Cost Avoidance: For PNG to make the necessary improvements independently of RIPET, on the main artery on Ridley Island, the Company would have had to incur significant costs in the near-term. Further, it is highly possible that PNG would have been directed to conduct a major relocation, as PNG is on the Ridley Island at the pleasure of PRPA with weak land rights. While PNG did not provide detailed cost estimates independent of RIPET, PNG anticipates the avoided costs to be in the $5-$7 million range to address the above issues, and that's assuming PNG was not mandated to upgrade the line in any event by PRPA, CN or the BCOGC.

In summary, PNG's existing customers have leveraged a major opportunity by piggybacking onto the RIPET project, therefore receiving a large array of benefits for a fraction of the costs.

71.2.2 If not, please discuss if a contribution in aid of construction was received in relation to the three projects identified above and if not, why not.

Response:

Please see the response to Question 71.2.1.

71.3 What was the total cost for each of the three Ridley Island integrity improvement projects (Cathodic Protection, Distribution Pressure Pipeline System, High Pressure Pipeline System)?

Response:

The total cost incurred by the Ridley Island integrity improvement projects were as follows:

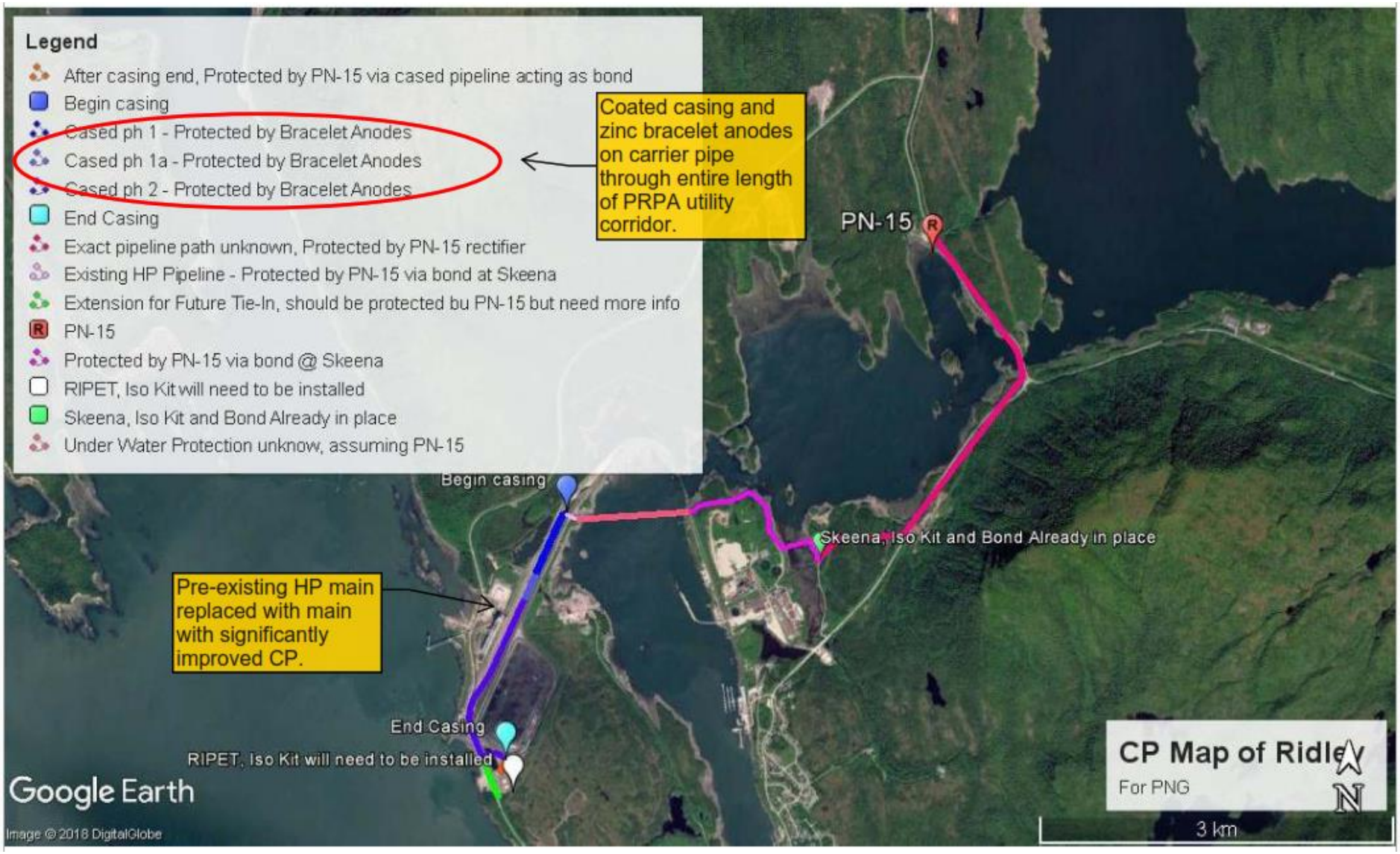
	System Betterment Allocation	
	2018	2019
Cathodic Protection System Improvements	$ 150,000	$ -
DP Pipeline System Improvements	$ 100,000	$ 343,140
HP Pipeline System Improvement	$ 450,000	$ 125,000
Total		$ 1,168,140

71.3.1 Please provide any engineering design, feasibility and risk assessment reports regarding these projects. If not included in these reports, please provide a schematic drawing or map to show scope boundary between the RIPET project and these three integrity improvement projects.

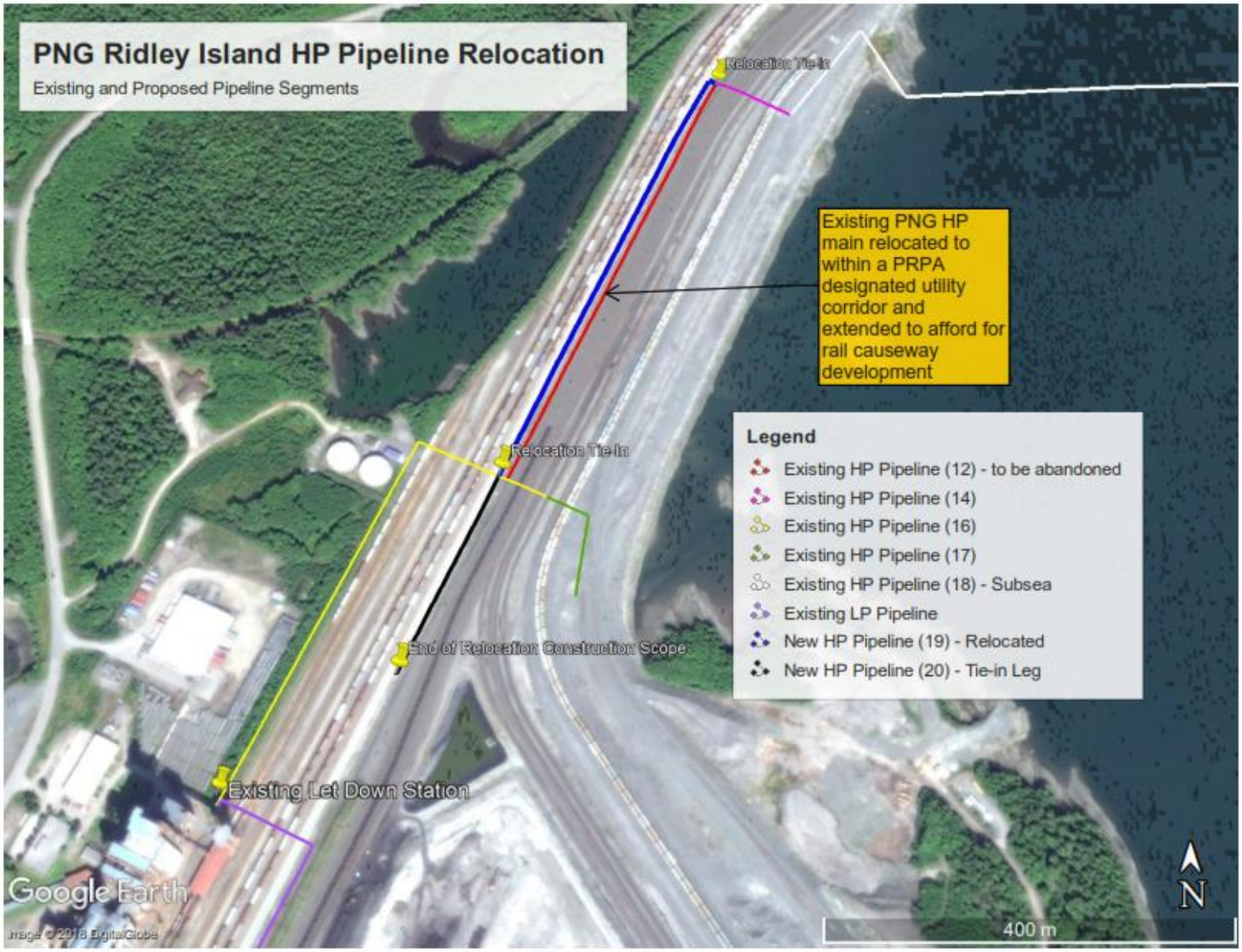
Response:

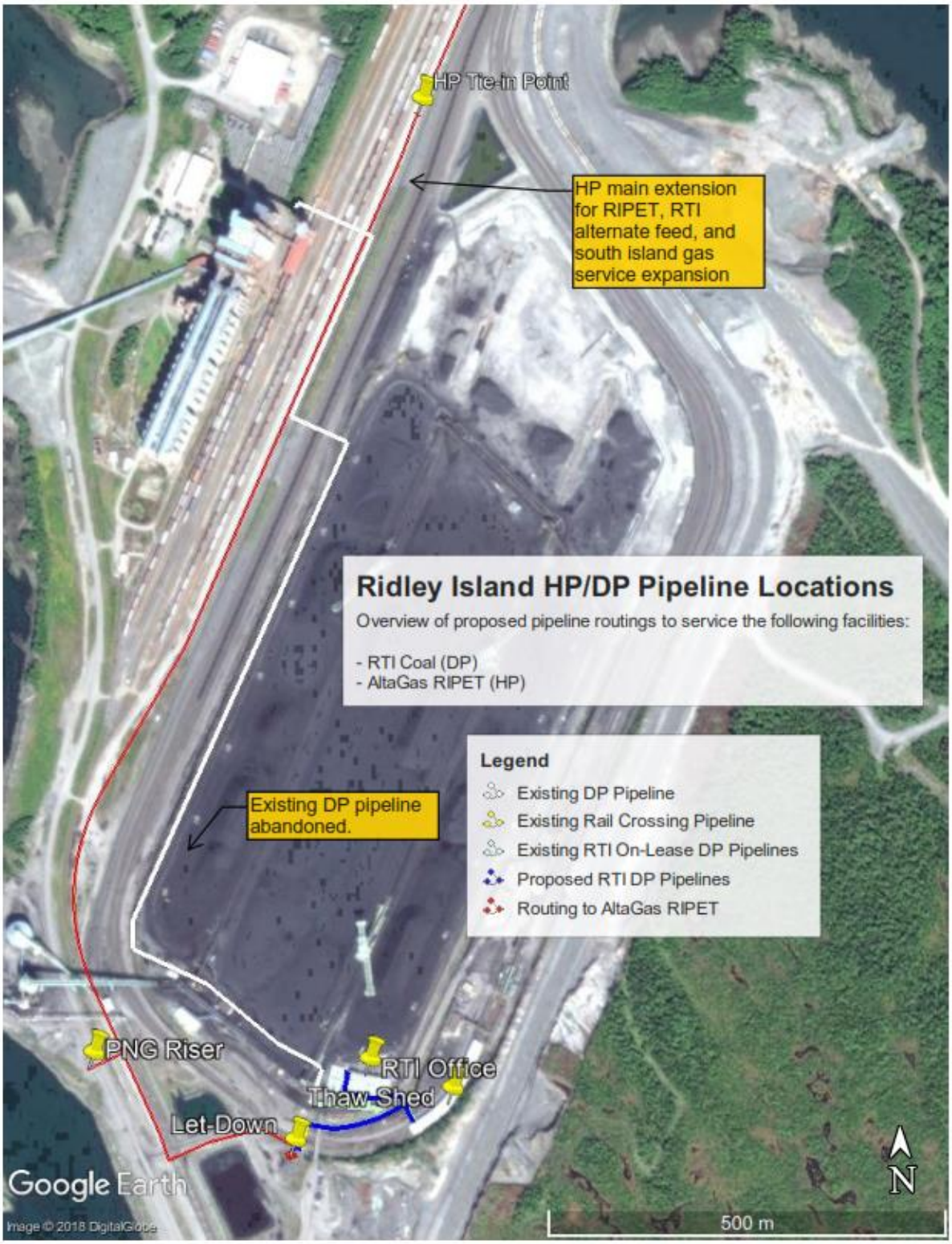
These projects were tributary to or a proportional allocation of the much larger project undertaking on Ridley Island that was recovered via RIPET CIAC. There were no design, feasibility, or risk related reports specifically attributed to the general improvements identified above.

PNG submits that the annotated aerial images provided on the pages that follow provide the best visual scope delineation and explanation of pipeline system benefits external to RIPET.


Legend
After casing end, Protected by PN-15 via cased pipeline acting as bond
Begin casing
Cased ph 1 - Protected by Bracelet Anodes
Cased ph 1a - Protected by Bracelet Anodes
Cased ph 2 - Protected by Bracelet Anodes
End Casing
Exact pipeline path unknown, Protected by PN-15 rectifier
Existing HP Pipeline - Protected by PN-15 via bond at Skeena
Extension for Future Tie-In, should be protected bu PN-15 but need more info
PN-15
Protected by PN-15 via bond @ Skeena
RIPET, Iso Kit will need to be installed
Skeena, Iso Kit and Bond Already in place
Under Water Protection unknow, assuming PN-15
Coated casing and zinc bracelet anodes on carrier pipe through entire length of PRPA utility corridor.
PN-15
Begin casing
Skeena, Iso Kit and Bond Already in place
Pre-existing HP main replaced with main with significantly improved CP.
End Casing
RIPET, Iso Kit will need to be installed
Google Earth
Image © 2018 DigitalGlobe
CP Map of Ridley
For PNG
N
3 km


Operation Gas Map
User Manual
IT Support
56 - Ridley Terminal
Flow through existing pressure letdown station limited to PR Grain and Quickload. Frees up station capacity for expansion west of rail yard.
Existing DP pipeline through coal handling yard decommissioned.
HP main relocation and extension within PRPA utility cooridor
HP System South Stub - Provides south expansion opportunity
DP Backfeed to Ridley Terminals via new pressure letdown station
Kaien Island
0.3km
-130.35142 54.22404 Degrees


PNG Ridley Island HP Pipeline Relocation
Existing and Proposed Pipeline Segments
Relocation Tie-In
Existing PNG HP main relocated to within a PRPA designated utility corridor and extended to afford for rail causeway development
Relocation Tie-In
End of Relocation Construction Scope
Existing Let Down Station
Legend
Existing HP Pipeline (12) - to be abandoned
Existing HP Pipeline (14)
Existing HP Pipeline (16)
Existing HP Pipeline (17)
Existing HP Pipeline (18) - Subsea
Existing LP Pipeline
New HP Pipeline (19) - Relocated
New HP Pipeline (20) - Tie-in Leg
Google Earth
Image © 2018 DigitalGlobe
N
400 m


HP Tie-in Point
HP main extension for RIPET, RTI alternate feed, and south island gas service expansion
Ridley Island HP/DP Pipeline Locations
Overview of proposed pipeline routings to service the following facilities:
- RTI Coal (DP)
- AltaGas RIPET (HP)
Legend
Existing DP Pipeline
Existing Rail Crossing Pipeline
Existing RTI On-Lease DP Pipelines
Proposed RTI DP Pipelines
Routing to AltaGas RIPET
Existing DP pipeline abandoned.
PNG Riser
RTI Office
Thaw Shed
Let-Down
Google Earth
Image © 2018 DigitalGlobe
500 m
N

71.4 Please elaborate how the high-pressure pipeline system improvement scope of work described above was not directly associated with the RIPET service request.

Response:

As described in the responses to the Question 71 series above, the RIPET service request provided a cost avoidance opportunity for work that would have otherwise been required, driven by CN Rail and PRPA due to ongoing and emerging overall island developments and a PNG land position that did little to protect PNG interests. While much of the completed work was coincidental with work that benefitted and was necessitated by RIPET, the work associated with high-pressure mainline re-alignment, depth of cover adequacy, CP and other integrity improvements, and ability to continue serving existing and future customers would have been required regardless.

72.0 Reference: CAPITAL EXPENDITURE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.1.1, p. 128
2018 Capital Expenditure Variance Analysis – Compressor Station Upgrades (greater than approved by $685,000)

On page 128 of the Amended Application, PNG states:

> This project involved a series of compressor upgrades across the PNG-West system that have been deferred, but now must proceed to keep the facilities in a safe operation condition. The overall variance is due to the sum of a number [of] individual variances…
>
> PNG-West had planned to install new station valves at compressor station R1…additional costs were incurred for extra engineering work necessary to provide accurate measurements for the length and height of the pipework to ensure ease of construction…
>
> PNG-West had also planned to remove lead paint and to paint above ground piping at compressor station R2 ($375,000), however this project costs were greater than budget by $182,000. As the lead paint was removed at the site, cracks in the pipework became evident and had to be assessed and addressed.

72.1 Please elaborate on why the issues which led to the additional costs were not included in the original forecast.

Response:

For the valve installation at R1, it was the first time that this type of complex project had been undertaken by PNG and its project team. As such, the project team had underestimated the amount of engineering works that would be required to ensure that the project was delivered in an efficient and effective way.

For the painting works at R2, conducted in 2018, PNG had no historical reporting or corporate knowledge of excessive cracking on any of its station's pipework. The cracking could not be identified until the paintwork had been removed. Once the cracking was identified, it had to be inspected and dealt with to ensure no integrity issues were hidden down the line. With activities necessary to maintain safe and reliable operations, PNG could not manage to the original budget.

Despite the prudently incurred variances on the aforementioned projects, PNG was able to find offsets within other projects in its overall System Betterment budget, thereby effectively managing the overall capital program.

72.2 Please discuss any measures PNG has implemented in order to address the compressor station upgrade cost variances and how these have been factored into the Test Year 2020 and 2021 costs.

Response:

Lessons learned are a key part to ensuring future efficient and effective project delivery. The project team involved in the delivery of these projects have encompassed these lessons learned and have built then into all projects scheduled for 2020 and 2021.

For example, with the works at the R4 painting project conducted in 2019, provisions were made for the potential of finding the cracking. When the project was conducted, cracking was found and dealt with in an efficient and effective manner. The project was subsequently delivered under budget when compared to the newly provisioned budget.

73.0 Reference: CAPITAL EXPENDITURE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.1.2, p. 130
2019 Capital Expenditure Variance Analysis – Carryforward Projects

On page 130 of the Amended Application PNG presents Table 45, a portion of which is included below:

Carryforward Projects					
Ridley Island Propane Export Terminal (RIPET) Gas Supply	NB	465	757,063	-	(757,063)
Kleanza Creek Crossing Repair	SB	465	746,172	-	(746,172)
Highway 16/37 Skeena Station Relocation	SB	463	673,496	-	(673,496)
Final Report on 2018 EMAT ILI MP 0-66.7 R1-R2	SB	465	334,188	-	(334,188)
Copper River MP 250 Repair	SB	465	51,286	-	(51,286)
Subtotal			2,562,204	-	(2,562,204)
Total Capital Expenditures excluding Overhead and Approved CPCN Projects			**9,303,510**	**5,146,710**	**(4,156,800)**
CPCN Projects without Overhead					
Pembina Watson Island Gas Supply	NB	463/465	971,158	3,142,000	2,170,842
LNG Canada Let Down Station #2 Gas Supply	NB	472/477	1,222,332	1,558,800	336,468
Subtotal			2,193,489	4,700,800	2,507,311
Total Capital Expenditures without Overhead			**11,496,999**	**9,847,510**	**(1,649,489)**

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

73.1 Please identify any measures that have been undertaken by PNG in its capital project planning and scheduling process to address timing issues with its capital projects.

Response:

PNG submits that it has made significant improvements in the planning and management of capital projects in recent years, including enhancing its internal engineering capabilities, investing in technologies, and working with suppliers to ensure services and materials are provided on a timely basis.

PNG submits that this question implies that the existence of carryforward projects reflects weaknesses in planning and scheduling. PNG directs the BCUC to the narrative on the carryforward projects provided on pages 133 and 134 of the Amended Application, which documents the origin of the requirement to extend the noted projects beyond the planned construction period, and notes that the change in timing on these items has been outside of PNG's control in all instances.

73.2 For each for the carryforward projects and CPCN projects identified in the preamble, please provide the forecast and actual total project costs.

Response:

Please see the table that follows.

	Project Type	Plant in Service Account Number	2017 Actual	2018 Actual	2019 Actual	Total project cost	2020 forecast	Total project forecast	Decision
Carryforward Projects									
Ridley Island Propane Export Terminal (RIPET) Gas Supply	NB	465	139,622	3,696,962	757,063	4,593,647	-	4,593,647	4,500,000
Kleanza Creek Crossing Repair	SB	465	195,101	66,443	746,172	1,007,716	110,000	1,117,716	-
Highway 16/37 Skeena Station Relocation	SB	463	-	419,046	673,496	1,092,542	54,000	1,146,542	256,000
Tool Run and Final Report on 2018 EMAT ILI MP 0-66.7 R1-R2	SB	465	-	1,270,891	334,188	1,605,079	-	1,605,079	1,232,474
Copper River MP 250 Repair	SB	465	101,508	5,605,616	51,286	5,758,409	600,000	6,358,409	5,683,000
Subtotal			436,232	11,058,957	2,562,204	14,057,394	180,000	14,237,394	11,671,474
CPCN Projects without Overhead									
Pembina Watson Island Gas Supply	NB	463/465	-	-	971,158	971,158	1,317,865	2,532,328	3,142,000
LNG Canada Let Down Station #2 Gas Supply	NB	472/477	-	-	1,222,332	1,222,332	-	1,222,332	1,558,800
Subtotal			-	-	2,193,490	2,193,490	1,561,170	3,754,660	4,700,800

74.0 Reference: CAPITAL EXPENDITURE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.1.2, p. 132
2019 Capital Expenditure Variance Analysis – Structure Improvements

On page 132 of the Amended Application, PNG states:

> The cost variance for this expenditure classification can be attributed to PNG incurring approximately $996,000 on tenant improvements to modify the leased space. These costs were offset in part by a tenant inducement allowance of $346,000. The costs incurred were based on a fixed-price design build contract to minimize the risk due to tendering costs and scheduling risk, and are consistent with per square foot costs for tenant improvement projects.

74.1 Please provide further information to justify that the structure improvement costs are consistent with per square foot costs for tenant improvement projects.

Response:

PNG referred to the Altus Group 2019 Canadian Cost Guide which is publicly available in establishing a budget for the tenant improvements required. Page 10 of the Guide specified a range of $100 to $190 per square foot for Interior Fitout for a Class A building. PNG initially assumed a budget of $150 per square foot to renovate the space which includes 8,657 square feet, or $1.3 million. PNG was able to complete the tenant improvements for $115 per square foot, which after tenant inducement allowance was equivalent to $75 per square foot.

M. COST OF SERVICE REPORTING – ACTUAL VS DECISION

75.0 Reference COST OF SERVICE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.2.2.1, p. 145
Account 685 – General Operations 2019 Variance

On page 145 of the Amended Application, PNG states:

> The actual costs for 2019 included in this account are $993,000 or 32.9% lower than those approved under Decision 2019. This variance can be attributed to a number of factors, including GIS-related costs of $275,000 budgeted for 2019 as an operating cost that were capitalized. Similarly, there were $254,000 in Maximo licensing costs budgeted as an operating cost in 2019 that were subsequently capitalized. Lastly, there were saving realized from staff vacancies during 2019.

75.1 Please confirm that the total 2019 costs previously budgeted as operating costs and subsequently capitalized are $529,000. If not confirmed, please provide details of any 2018 and 2019 costs that were previously classified as expense items and have been subsequently capitalized.

Response:

PNG notes that the variance pertaining to GIS-related costs is only $200,000, and not $275,000 as originally reported in the Amended Application. Furthermore, PNG notes that this variance was due to GIS operational costs that were not incurred in 2019 because of a strategic decision to delay the rollout of the project. PNG apologizes for the typographical and representational errors. The GIS costs that have been capitalized are reported in the response to Question 53.1, and are consistent with the forecast amounts. The amount of costs that were previously budgeted as operating costs and subsequently capitalized was $254,000, specifically the costs related to Maximo.

75.1.1 Please confirm or explain otherwise that the 2019 costs were expensed and recovered in rates and clarify if these costs will subsequently be recovered through depreciation.

Response:

PNG confirms that these 2019 costs approved under Decision 2019 for GIS and Maximo were reflected in the cost of service for 2019 and recovered in rates set for that year. PNG further confirms that the Maximo costs capitalized will subsequently be recovered in future rates by virtue of the depreciation of these costs being included in the cost of service for future years.

However, PNG notes that, given the nature of the rate setting process, during the course of each year there are variances, both favourable and unfavourable, from the forecast cost of service for any particular test period. To consider specific unfavourable variances for disallowance is not appropriate as it does not consider the fact that on an overall basis the impact is likely to be marginal.

75.2 Please describe the nature of the GIS-related costs that are referenced in the preamble.

Response:

As noted in the response to Question 75.1, these costs were anticipated to be ongoing operational costs that would be incurred post-implementation of the GIS project. PNG determined strategically to defer the roll-out of the GIS system, and therefore the anticipated costs of $200,000 were not incurred in 2019.

75.3 Please explain the reasons why the GIS-related costs and Maximo licensing costs were previously treated as expenses and why they are now being capitalized.

Response:

As noted in the response to Question 75.1, only the Maximo licensing costs have now been capitalized. The reason for the change in accounting treatment can be attributed to the fact that the Maximo system is to be deployed to employees later than the date originally anticipated when the 2018-2019 Revenue Requirements Application was under review. Under US GAAP qualifying license costs and the related software support and other development costs can be capitalized during the application development stage, which is why these costs have been capitalized rather than being expensed.

75.4 Please provide the 2019 variance amount that is related to staff vacancies, the reasons for the staff vacancies and whether these vacancies have since been filled.

Response:

PNG does not explicitly track variance amounts related to staff vacancies. The labour variance for 2019 was approximately $100,000, but note that this also includes any other variances relating to labour due to variances in hours worked, overtime worked, etc. Staff vacancies occur for a variety of reasons, including lags between the departure of employees and the timing of the replacement of employees to fill those positions. There were two staff vacancies contributing to the $100,000 variance for 2019, and both of these were filled by the end of 2019.

76.0 Reference COST OF SERVICE REPORTING – ACTUAL VS DECISION
Exhibit B-2, Section 3.2.2.1, p. 148
Account 725 – Employee Benefits 2019 Variance

On page 145 of the Amended Application, PNG states:

> The actual costs for 2019 included in this account are $378,000 or 10.6% lower than those approved under Decision 2019. This variance is primarily attributable to the recovery of $319,493 in costs pertaining to services provided to affiliate entities.

76.1 Please explain how the recovery of 2019 costs pertaining to services provided to affiliate entities was recorded and whether the recovery was to the account of PNG's shareholder or the ratepayer.

Response:

The recovery of 2019 costs pertaining to services provided to affiliate entities was not contemplated in the 2018-2019 Test Years, as at that time PNG was owned by AltaGas Ltd. and there were no services being provided to affiliate entities.

As a result of the ownership being transferred from AltaGas Ltd. to TriSummit Utilities Inc. (TSU, formerly ACI), both of PNG's President and PNG's Director of Business Development took on additional roles for affiliated entities. 2019 cost recoveries were charged to the affiliate entities using charge-out rates that were based on the employee's salaries including charges for benefit loadings, corporate overhead and facilities charges.

PNG submits that the impact of these recoveries was neutral to both ratepayers and the shareholder. This is because neither the incremental costs (i.e. additional compensation for the President and Director of Business Development for these expanded roles) nor incremental recoveries were reflected in the cost of service underlying the rates established for 2019. For 2020 onward, the incremental costs and recoveries will be reflected in the cost of service, and PNG has proposed a deferral account to capture any variances between actual and forecast.

N. IDENTIFIED SERVICE QUALITY METRICS

77.0 Reference: IDENTIFIED SERVICE QUALITY METRICS
Exhibit B-2, Section 3.3, p. 151; PNG-West 2018-2019 RRA proceeding, Exhibit B-3, BCUC IR 54.1;
Identified Service Quality Metrics

In response to BCUC IR 54.1 in the PNG-West 2018-2019 RRA proceeding, regarding specific benchmarks that PNG works towards with respect to the key service quality metrics, PNG provided the following response:

> PNG is a member of the Canadian Gas Association and compares its quality service metrics to those of other utilities across Canada, where applicable. Each utility has its own unique influences that affect their metrics. For example, PNG is one of the smallest utilities and is spread over a very large geographical area and this influences response times to customers in remote areas. A larger utility may have many resources in a heavily populated area, which may provide a different impact on response times. PNG monitors the metrics regularly for change and then address accordingly. The Lost-time Injury Frequency Rate is also a key metric that has benchmarking with the CGA.

77.1 Please confirm or explain otherwise, that PNG continues to benchmark the key service quality metrics on page 151 of the Amended Application to other utilities which are members of the Canadian Gas Association.

Response:

PNG benchmarks certain metrics against the Canadian Gas Association (CGA), including additional metrics that are not an element of the service quality metrics reported to the BCUC.

77.1.1 If confirmed, please discuss whether PNG-West is considered to be performing well based on these metrics compared to other utilities in Canada overall. Please outline any specific metrics which require significant improvement compared to benchmarks.

Response:

PNG has made improvements to its performance when benchmarked with the Canadian Gas Association (CGA). When reviewing the BCUC reported service quality metrics that are formally benchmarked, the Lost Time Injury Frequency Rate is the only one that can be directly compared. The other metrics are PNG-specific without good industry comparators. However, for the purposes of this question, PNG will provide analysis on the LTIFR and two other CGA benchmarked metrics -- Preventable Motor Vehicle Incident Rate and Third Party Damage rate -- to illustrate PNG's performance against the industry.

Lost-time Injury Frequency Rate

The Lost-time Injury Frequency Rate (LTIFR) has been highlighted in the information produced in the preamble to this question. The following displays the average LTIFR from PNG and the CGA average for distribution utilities.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
PNG	**2.01**	**1.01**	**2.84**	**1.90**	**1.81**	**0.90**
CGA average	0.53	0.74	0.62	0.55	0.39	0.77

PNG acknowledges that its LTIFR has been above the CGA average over the past six years. The Company has made some marked improvements in safety management systems in the past two years that have had a positive effect. Currently, PNG has not had a Lost Time Injury since January 2019. Further, based on the size of PNG (i.e. ~120 employee), one incident can have a major impact on the calculation. For example, for the LTI in January 2019, while concerning, resulted in 4 lost days of work by one employee – the only lost time in the entire year, which put PNG over the CGA average.

Total Preventable Motor Vehicle Incident - Frequency Rate (TPMV-F)

A second metric that is benchmarked closely with the CGA is Total Preventable Motor Vehicle Incident - Frequency Rate (TPMV-F). Again, PNG has made some marked improvements to this metric. PNG can attribute this improvement to the heightened safety culture, implementation of the GeoTab system, and additional driver training. The GeoTab system provides data on employee driving behaviours, and PNG actively manages the reporting. PNG has been in the top quartile of CGA companies for the past three years.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
PNG	**1.13**	**2.89**	**5.19**	**1.29**	**0**	**1.36**
CGA Average	2.14	2.23	2.59	2.05	1.16	2.40

Third Party Damages per Third Party Locate Requests

A third metric that is benchmarked closely with the CGA is Third Party Damages Per Third Party Locate Requests. This metric is focused on measuring the effectiveness of damage prevention programs. PNG has historically been slightly higher than the CGA average, but is making some improvements through a heightened safety culture and improved damage awareness campaigns.

	2014	**2015**	**2016**	**2017**	**2018**	**2019**
PNG	**2.6**	**2.9**	**3.5**	**2.8**	**2.7**	**1.4**
CGA Average	2.7	2.7	2.6	2.3	2.5	Not available

PNG provided the following key service metrics on page 151 of the Amended Application:

Service Quality Metric	2019	2018	2017	2016	2015
Number of Emergency Calls	331	302	301	417	410
Average Response Time per Call	17 minutes	20 minutes	19 minutes	15 minutes	18 minutes
Number of Calls with a Response Time over 40 Minutes	45	39	39	35	52
Number of Underground Leaks	14	27	27	15	11
Number of Reportable Environmental Incidents	–	–	–	–	1
Lost-time Injury Frequency Rate *	0.90	2.08	2.07	2.84	1.01
Customer Complaints to the BCUC **	4	3	2	0	3

77.2 Please explain any factors that contributed to the increase in the number of emergency calls in 2019 as compared to 2018 by 29 calls.

Response:

Most of PNG's emergency calls are gas odour calls called in by customers and, to a lesser degree, for hit lines – this is typical for gas utilities. PNG recognizes there was a 9% increase from 2018 to 2019, however notes that the 2019 number was also 8% lower than the previous 4-year average. While PNG takes each odour call and hit line extremely seriously, PNG recognizes the statistics are still within 10%. PNG cannot definitively attribute any specific factors to the variation. However, the increase may be due to increased public awareness following damage prevention campaigns and increased social media campaigns.

77.2.1 Please discuss any risks associated with the factors identified and measures PNG has undertaken to mitigate these risks.

Response:

There are presently no additional risks that have been identified. PNG will continue to monitor the situation with regards to emergency calls.

77.3 Please explain why there were 6 more calls in 2019 with a response time over 40 minutes compared to 2018.

Response:

PNG monitors emergency response very closely. In this case, while the overall number is higher, the percentage increase of number of calls with a response time over 40 minutes has only increased by 1% year-over-year (46 in 339 (13.9%) versus 39 in 302 (12.9%)). There are several of factors that could account for this small increase including weather hampering the safe driving speed of the responder and the additional traffic on the roads (traffic has increased recently due to major construction projects in the area). PNG will continue to monitor its response times and put appropriate measures in place as required to ensure public safety.

O. OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS

78.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, pp. 153-154
Reporting on Significant Capital Projects – Focus on Non-recurring Expenditures

On page 153 of the Amended Application, PNG states:

> PNG proposes that the reporting on forecast capital expenditures be limited to planned non-recurring capital projects. Expenditures classified as planned non-recurring projects would capture system extensions, new facilities and significant system modifications or additions. Planned non-recurring projects would also capture items that pertain to the maintenance and operation of existing assets such as the 2018 Copper River MP 250 emergency repair, or other non-discretionary items such as capital expenditures necessary to respond to BC Ministry of Transportation and Infrastructure (MoTI) directives to relocate facilities within the public right of way.

78.1 Please explain if new IT systems, or upgrades to existing systems, will be included in planned non-recurring capital expenditures. If not, why not.

Response:

New IT systems, or upgrades to existing systems, will be included in the proposed reporting on significant capital projects if the cost of the planned non-recurring IT-related capital expenditures meets the proposed threshold amount of $500,000. However, PNG notes that all capital projects would be subject to BCUC approval through the RRA, CPCN or other application process.

78.2 Please describe the process that PNG undertakes in order to classify capital expenditures as non-recurring or recurring and the criteria for including capital expenditures as recurring items.

Response:

The criteria for assessing whether capital expenditures are recurring or non-recurring are primarily based on whether the cost to be incurred is related to a non-routine specific project, or whether it would typically be expected to recur on a routine, annual basis to support the ongoing provision of service to customers. Examples of these criteria are provided on pages 153 and 154 of the Amended Application. PNG notes that these classifications were established in 2013 in consultation with BCUC Staff.

Table 45 on page 130 of the Amended Application has further examples of capital projects and how the segregation of these items between recurring and non-recurring activities is based on the nature of the expenditure.

79.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, pp. 154
Reporting on Significant Capital Projects – Recommended Minimum Dollar Threshold

On page 154 of the Amended Application, PNG states:

> PNG proposes a cumulative minimum total capital project expenditure of $500,000 for project reporting purposes. PNG considers that capital projects of lesser amounts would not warrant further examination through a separate review process.

79.1 Please explain how the threshold for the minimum capital project expenditure was derived and any specific factors that were considered in proposing this amount.

Response:

Directive 5 of Order G-151-18 requested that PNG file a proposal for an annual reporting to outline future construction of extension and new facilities as well as any significant system modifications or additions that are planned. PNG determined that a $500,000 threshold was appropriate after completing a historic review of non-recurring capital expenditures, and identified that most of the individual projects fell above a $500,000 threshold.

PNG submits that this report will provide the BCUC a view of upcoming significant projects, but PNG will nevertheless seek BCUC approval of individual significant capital projects through its revenue requirements, CPCN or other applications. PNG also notes that its two-year revenue requirements applications 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. The $500,000 threshold was also determined based on striking 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 additional costs for compliance.

79.2 Please provide a table that shows the proposed threshold of $500,000 as a percentage of actual capital expenditures for each year between 2015 and 2019. Please discuss if the total amount of historic capital expenditures was considered in determining the threshold.

Response:

Please see the table that follows.

($000's)	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
Proposed threshold	500	500	500	500	500
Actual capital expenditures	11,497	17,860	4,272	4,609	3,868
Threshold as % of Actual	4.3%	2.8%	11.7%	10.8%	12.9%

As noted in response to Question 79.1, PNG determined that a $500,000 threshold was appropriate after completing a historic review of non-recurring capital expenditures which identified that most of the individual projects fell above a $500,000 threshold. As per the table provided in response to Question 79.4, a $500,000 limit would capture most capital expenditures in the reporting, for example close to 70% of capital projects in years 2017 to 2019 would be included in the proposed reporting.

79.2.1 Please discuss other thresholds that may have been considered, and why they were ultimately not selected.

Response:

As noted in the response to Question 79.1, the request of the directive was to provide the BCUC with annual reporting on capital spending specifically related to project work. Most planned non-recurring projects now exceed a $500,000 threshold, so other lower dollar thresholds were not considered. Higher dollar thresholds were also not considered, as PNG felt that there were projects between $500,000 and $1,000,000 that the BCUC would be interested in having PNG include in the report.

PNG also points out that BCUC approval will be required for individual significant capital projects through its revenue requirements, CPCN or other applications.

79.2.2 Please discuss the pros and cons of having separate thresholds for different types of capital expenditures (i.e. IT project, transmission project, distribution project).

Response:

PNG believes the benefit of using a consistent threshold across all of the Plant in Service classes is important as it provides uniform criteria for the report parameters. As noted in the various responses and tables provided in this series of questions, important non-recurring projects are already captured in the $500,000 threshold criteria, regardless of the type of capital expenditure incurred.

A further drawback to using different thresholds is that it would make the proposed report format significantly more complicated and confusing, as the various "buckets" for consolidating expenditures under the thresholds for each type of capital expenditure would all have to be separately identified.

PNG reiterates that BCUC approval will be required for individual significant capital projects through its revenue requirements, CPCN or other applications.

79.2.3 Please provide a table that shows the proposed threshold of $500,000 as a percentage of actual IT capital expenditures for each year between 2015 and 2019. Based on the results, please discuss the benefits of having a different threshold for IT capital expenditures.

Response:

Please see the table that follows.

	BCUC	Actual 2019	Actual 2018	Actual 2017	Actual 2016	Actual 2015
Proposed Threshold		$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
- as a % of Planned Non-Recurring		33.5%	77.5%	N/A	N/A	N/A
- as a % of Total IT Expense		30.3%	53.6%	548.5%	177.1%	629.8%
Planned Recurring IT Expense						
Computing Hardware/Software	487	$ 159,315	$ 287,495	$ 91,164	$ 282,363	$ 79,389
Planned Non-Recurring IT Expense						
Geographic Information System	487	629,396	446,052	-	-	-
Asset Records Modernization	487	249,676	199,373	-	-	-
Computer Hardware/Software	487	612,676	-	-	-	-
		1,491,748	645,425	-	-	-
Total IT Expense		$ 1,651,063	$ 932,920	$ 91,164	$ 282,363	$ 79,389

As per the table, PNG's planned recurring IT capital expenditures have been below $300,000 in each of the last five years. These expenditures are primarily for replacement of hardware, including servers and laptops which need to be replaced every 3 to 5 years. Expenditures for software have included upgrades for the CISCO phone system used in the Customer Care centre, which were also less than $50,000. Given the small size of these projects and that they represent a recurring requirement to operate the company, PNG does not believe a different threshold for these planned recurring expenditures is required.

For planned non-recurring IT capital projects, PNG notes that all the projects listed in the table would be included in the report as they exceed the $500,000 threshold. The Asset Records Modernization project is a multi-year project with an additional budget of $182,029 for 2020 as per Table 38 in the Amended Application so that project would exceed the $500,000 threshold. Therefore, PNG also concludes that a different threshold for planned non-recurring IT capital expenditures is not required.

79.3 Please clarify whether the minimum dollar threshold applies to the annual forecast capital expenditure or the total project costs.

Response:

The proposed minimum dollar threshold would be applied to total project costs.

79.4 Please provide a complete listing of the 2017, 2018 and 2019 non-recurring capital expenditures by project and indicate which projects would have been reported based on a $500,000 threshold.

Response:

Please see the table that follows. Note that the far-right column of the table indicates which projects would have been reported based on a $500,000 threshold.

	Project Type *	Plant in Service Account Number	2019 Actual Expenditure Excluding Overhead	2018 Actual Expenditure Excluding Overhead	2017 Actual Expenditure Excluding Overhead	Total	> $500,000
Planned - Non-Recurring							
Geotechnical Information System	GP	487	629,396	446,052	-	1,075,448	Yes
Structure Improvements	GP	472/482	1,105,203	43,868	92,594	1,241,665	Yes
Transmission Mainline Repairs and Assessments	SB	465	569,845	1,524,927	47,445	2,142,217	Yes
Compressor Station Upgrades	SB	466	414,759	2,457,096	424,198	3,296,053	Yes
Compressor Spare Overhaul	SB	469	481,881			481,881	No
Replace Line Heaters	SB	467	-	495,780	89,150	584,930	Yes
Asset Records Modernization	GP	487	249,676	199,373	-	449,049	No
Meter & Regulating Station Upgrades	SB	467	68,213	32,356	-	100,569	No
Automatic Meter Reading Pilot Project	SB	478	-	235,985	-	235,985	No
Computer Hardware/Software	GP/GP-I	487	612,676	-	-	612,676	Yes
Ridley Island Propane Export Terminal (RIPET) Gas Supply	NB	465	757,063	3,696,962	139,622	4,593,647	Yes
Kleanza Creek Crossing Repair	SB	465	746,172	-	-	746,172	Yes
Highway 16/37 Skeena Station Relocation	SB	463	673,496	-	-	673,496	Yes
Final Report on 2018 EMAT ILI MP 0-66.7 R1-R2	SB	465	334,188	-	-	334,188	No
Copper River MP 250 Repair	SB	465	51,286	5,605,616	-	5,656,902	Yes
Pembina Watson Island Gas Supply	NB	463/465	971,158	-	-	971,158	Yes
LNG Canada Let Down Station #2 Gas Supply	NB	472/477	1,222,332	-	-	1,222,332	Yes
Access Upgrades - Work Channel & Gitnadoix	SB	465	-	-	83,643	83,643	No
Other System Betterments	SB	468	-	-	306,765	306,765	No
MP 299 Repair Work 2017	SB	465	-	-	702,958	702,958	Yes
Total Planned - Non-Recurring Projects			**8,887,343**	**14,738,015**	**1,886,375**	**25,511,733**	
Total Capital Projects			**11,496,999**	**17,860,386**	**4,271,840**	**33,629,225**	
Planned - Non-Recurring Projects as % of Total Capital Projects			**77.3%**	**82.5%**	**44.2%**	**75.9%**	
Projects Exceeding $500,000 Threshold			**7,753,385**	**14,270,301**	**1,495,967**	**23,519,653**	
Projects Exceeding $500,000 Threshold as % of Total Capital Projects			**67.4%**	**79.9%**	**35.0%**	**69.9%**	

79.4.1 For each year, please provide the capital project expenditures above the threshold as a percentage of the total capital expenditures.

Response:

Please see the response to Question 79.4.

79.5 Beyond a dollar threshold, please discuss whether other project characteristics were considered in determining which projects should be included in any annual reporting on capital expenditures (i.e. public interest).

Response:

PNG did not consider other project characteristics beyond a dollar threshold in determining which projects should be included in the proposed reporting. PNG observes that the BCUC directive for the proposed reporting was in the context of allowing the BCUC an opportunity to assess whether a CPCN process would be in the public interest and, for the sake of regulatory efficiency, PNG would not anticipate undertaking a CPCN process for a project with a cost less than $500,000. In addition, PNG considers all projects it proposes to undertake as necessary to providing safe, reliable service and therefore to be in the public interest.

79.5.1 For each characteristic, please comment on why it was ultimately not included as a reporting criterion.

Response:

Please see the response to Question 79.5.

79.6 Please explain how PNG will define an individual project for capital reporting purposes.

Response:

Items presently classified as Planned – Non-recurring items in it revenue requirements applications are generally clearly identifiable, discrete projects. PNG would continue with this determination of projects in the proposed reporting and include such projects in the report when the total project cost, on an aggregate basis, exceeds $500,000.

As described in the proposal included in the Amended Application, Planned – Recurring projects will not be included in the proposed annual reporting. Although in aggregate these expenditures may be significant, individually the project costs are generally not material and do not pertain to system extensions, new facilities and significant system modifications or additions.

79.7 Please discuss the pros and cons of establishing a minimum dollar threshold above which PNG would expect to file a CPCN or section 44.2 expenditure schedule with the BCUC.

Response:

Historically, PNG has generally filed CPCN applications for planned non-recurring projects that exceed $1,000,000. There have been exceptions where the timing for a planned expenditure was coincident with submission of a revenue requirements application and therefore approval has been sought via that path.

PNG considers the following to be some pros and cons for minimum dollar thresholds triggering the requirement to file a CPCN or section 44.2 expenditure schedule:

Pros

- Clear and consistent threshold for regulatory oversight
- Improve utility planning for major project applications

Cons

- Establishment of optimal value may be challenging
- Low risk, low complexity projects with minimal public interest impacts may be subject to review

79.7.1 From PNG's perspective, what are the relevant factors that should be considered in setting a minimum threshold for CPCN or section 44.2 expenditure schedules.

Response:

PNG suggests that the following factors would be relevant to setting a minimum threshold for CPCN or section 44.2 expenditure schedules:

- Materiality of expenditure
- Nature of expenditure (threshold may vary by type of expenditure)
- Timing of expenditure (potentially in between revenue requirements applications)

79.7.2 If a minimum threshold for filing CPCNs and 44.2 applications with the BCUC were set, please discuss what PNG would propose and why. Please provide the alternatives considered, and why the proposed minimum threshold was ultimately selected.

Response:

As noted in the response to Question 79.7, PNG has made use of an informal minimum threshold of $1,000,000 as a general guideline in deciding on whether to file CPCNs or 44.2 applications. A cursory review of other utilities under the BCUC's jurisdiction suggest that this threshold may be on the low side.

If a threshold were to be established, PNG suggests that a greater amount, say between $1,500,000 to $2,000,000, may be more appropriate. Based on actual experience for 2017 to 2019, projects at the $1,500,000 to $2,000,000 expenditure level would represent 13.4% to 17.8% of average total capital expenditures during this period. As per the table provided in response to Question 79.7.3 with data for 2015 to 2019, this higher threshold would reduce the regulatory burden on PNG, effectively requiring six to seven CPCNs during this time period compared to nine CPCNs required at the $1,000,000 threshold.

79.7.3 Please provide a table that shows projects with forecast expenditures above the proposed minimum threshold for each year between 2015 and 2019.

Response:

Please see the table that follows.

	Project Type *	Plant in Service Account Number	2019 Forecast Expenditure Excluding Overhead	2018 Forecast Expenditure Excluding Overhead	2017 Forecast Expenditure Excluding Overhead	2016 Forecast Expenditure Excluding Overhead	2015 Forecast Expenditure Excluding Overhead	Total
Planned - Non-Recurring								
Transmission Mainline Repairs and Assessments	SB	465	566,323	1,661,916	137,399	462,961		2,828,599
Compressor Station Upgrades	SB	466	387,173	1,771,794	701,534	204,000	302,000	3,366,501
Replace Line Heaters	SB	467	308,220	517,810	518,320	335,128	438,000	2,117,478
Ridley Island Propane Export Terminal (RIPET) Gas Supply	NB	465		4,500,000				4,500,000
Copper River MP 250 Repair	SB	465		5,683,000				5,683,000
LNG Canada Let Down Station #2 Gas Supply	NB	472/477	1,558,800					1,558,800
Pembina Watson Island Gas Supply	NB	463/465	3,142,000					3,142,000
Total Planned - Non-Recurring Projects			**5,962,516**	**14,134,520**	**1,357,253**	**1,002,089**	**740,000**	**23,196,378**

80.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, pp. 154
Reporting on Significant Capital Projects – Forecast Base

On page 154 of the Amended Application, PNG states:

> The base for reporting on forecast planned non-recurring expenditures would be the BCUC approved or test year amounts for the forecast period. For example, the forecast period presented in the Capital Report included in the 2019 Annual Report would commence with 2020 and PNG would present 2020 capital expenditures as applied for in its 2020-2021 Revenue Requirements Application as the forecast base.

80.1 Please clarify what is meant by "forecast base" and explain how it influences the reporting of significant capital expenditures.

Response:

PNG submits that "forecast base" may be a poor choice of terms. A better description in the context of the narrative reproduced in the preamble would be

> For example, the forecast period presented in the Capital Report included in the 2019 Annual Report would commence with 2020 and PNG would present 2020 capital expenditures as applied for in its 2020-2021 Revenue Requirements Application as the ~~forecast base~~ initial year for which reporting is provided.

81.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, pp. 155
Reporting on Significant Capital Projects – Report Format and Historic Expenditures

On page 155 of the Amended Application, PNG illustrates the proposed capital reporting format in the following table:

Table 55: Reporting on Significant Capital Expenditures – Report Format

Capital Project Description	Project Type *	Plant in Service Account Number	AACEI Estimate Class	Test Year 2020	Project Cost (Excluding Overhead)						
					Actual	Forecast					
					To 2019	2020	2021	2022	2023	2024+	Total
Planned - Non-recurring											
Approved/Test Year Projects											
Project A	GP	487	1	$ 671,126	$ 441,424	$ 700,000	$ 410,000	$ -	$ -	$ -	$ 1,551,424
Project B	GP	472/482	1	602,820	-	610,000	-	-	-	-	610,000
Project C	SB	465	1	566,323	361,442	500,000	-	-	-	-	861,442
Project D	GP	487	2	295,015	270,906	292,000	199,000	149,000	149,000	-	1,059,906
Anticipated New Projects											
2020 - New Project #1	GP	4XX	2	-			1,000,000	600,000	600,000	400,000	2,600,000
2020 - New Project #2	SB	4XX	2	-			600,000	-	-	-	600,000
2020 - New Project #3	SB	4XX	3	-			400,000	300,000	-	-	700,000
2020 - New Project #4	SB	4XX	4	-			250,000	300,000	-	-	550,000
2021 - New Project #1	GP	4XX	4	-				720,000	1,000,000	200,000	1,920,000
2021 - New Project #2	SB	4XX	5	-				500,000	-	-	500,000
				2,135,284	1,073,772	2,102,000	2,859,000	2,569,000	1,749,000	600,000	10,952,772
Other Projects <$500,000	Various	Various		781,633							-
Total - Planned - Non-recurring				$2,916,917	$1,073,772	$2,102,000	$2,859,000	$2,569,000	$1,749,000	$ 600,000	$10,952,772

* SB = System Betterment; NB = New Business; GP = General Plant; GP-I = General Plant - Intangibles

Further on page 155, PNG states:

> PNG's proposed reporting on historic expenditures would compromise a variance analysis of capital expenditures for the preceding calendar year.

81.1 Please explain whether the report format can be expanded to include:

(a) a column for the original budgeted costs, and a discussion of significant variances between the original budget and total (actual plus forecast) costs.
(b) a column for the estimated construction commencement date for each project.
(c) a column indicating whether the project would be filed as a CPCN or section 44.2 expenditure schedule with the BCUC

Response:

PNG confirms that the columns requested in (a), (b) and (c) can be expanded. Due to the tabular form of the report, the discussion of significant variances between the original budget and total (actual plus forecast) costs would be provided in narrative form below the report.

81.2 Based on the reporting format could there be projects that commences construction prior to the report being filed with the BCUC? If so, how does PNG propose to address this.

Response:

Again, PNG observes that the BCUC directive for the proposed reporting was in the context of allowing the BCUC an opportunity to assess whether a CPCN process would be in the public interest. Thus PNG has proposed a reporting format to meet this objective.

PNG 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 report being filed with the BCUC. To the extent that the project meets the requirements for the filing of a CPCN, a CPCN would be filed as soon as reasonable cost estimates could be completed to support a CPCN application.

Further, as noted in response to Question 83.1 , the report is not being provided to the BCUC as a request for approval, it is being provided for informational purposes. Therefore PNG does not consider the timing of the report submission to be linked to the approval to proceed with capital expenditures.

PNG reiterates that BCUC approval will be required for individual significant capital projects through its revenue requirements, CPCN or other applications.

81.3 Please confirm, or explain otherwise, that the reporting format will include all known capital projects that meet the reporting criteria regardless of how far in the future they are planned.

Response:

Confirmed. PNG would undertake to include all known capital projects for which the scope and cost estimate has been established. Consideration could be given to adding a short narrative to the proposed reporting for known projects for which these elements have not been fully developed.

82.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, pp. 156
Reporting on Significant Capital Projects – Supplemental Reporting

PNG states on page 156 of the Amended Application:

> PNG notes that given the nature of operating natural gas distribution and transmission facilities, there will be the need for unplanned or urgent capital projects to maintain ongoing safety, integrity, reliability, and compliance to codes, standards and regulations. These may be due externalities not anticipated. While PNG aims to minimize such occurrences, the BCUC should expect some unplanned projects that are not within the annual forecast. In such instances, where circumstances warrant consideration of the necessity for a CPCN for such projects, PNG commits to making the BCUC aware of the identified projects on an ad hoc and timely basis.

82.1 Please explain how much advance notice PNG will provide the BCUC prior to the construction commencement date for unplanned or urgent projects.

Response:

As noted in the preamble, PNG is committed to making the BCUC aware of such unplanned or urgent projects on an ad hoc and timely basis. PNG cannot state a specific notice period, but would undertake to provide notification of the requirement of the need for such projects as soon as reasonably possible.

83.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.1, p. 155
Reporting on Significant Capital Projects – Regulatory Review Process

On page 155 or the Amended Application, PNG states:

> PNG anticipates that the BCUC review would be completed on a timely basis, ideally within 30 days of submission, such that the review process would not hold up planned capital activities. On completion, as evidence of the review, the BCUC would provide PNG with a letter stating acceptance of the Capital Report.

83.1 Please clarify if PNG considers that acceptance of any annual report on capital expenditures implies BCUC approval of forecast expenditures.

Response:

PNG confirms that it considers the submission of the proposed report on capital expenditures to be a compliance submission and that this report does not imply any form of BCUC approval for forecast expenditures reported. The narrative reproduced in the preamble was to indicate PNG's expectation on the timing of the anticipated BCUC review of and feedback on the report, not approvals.

PNG reiterates that BCUC approval will be required for individual significant capital projects through its revenue requirements, CPCN or other applications.

84.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.4, pp. 161, 163.
GIS / ARM Benefit Analysis

On page 161 of the Amended Application, PNG states "At this stage of the project, PNG submits that it is therefore premature to assign any estimates to the costs that can be avoided by the introduction of the GIS."

On page 163, PNG states:

> PNG expects to realize these and other benefits once its GIS project is completed at the end of 2020. At that time, PNG may be in a position to associate a cost with these benefits.

On page 163, PNG also states:

> …PNG anticipates increased pressure on its operating costs related to engineering projects critical to PNG's ongoing compliance with heightened industry standards and pipeline-related regulations. PNG submits that its GIS, along with its ARM initiative will enable it to meet these challenges in the most cost effective manner possible, and avoid incurring costs for staff or contract resources that would otherwise be required to create and manage information most appropriately retained in a GIS.

84.1 Please elaborate on whether PNG expects to be able to quantify the cost savings associated with the GIS and ARM project benefits at the end of 2020. If not, please discuss the factors that prevent this.

Response:

As stated on page 163 of the Amended Application, and reproduced in the pre-amble to this question, PNG expects to be in a position to associate cost savings with its fully implemented GIS at the end of 2020, once the GIS project is completed. At this time, PNG is completing the configuration of the data and applications that are expected to result in more efficient workflows in the field and in the operations and head offices. A key component of the project is a redefinition of workflows related to asset management, integrity management, emergency planning, BC One Call management, drafting, and materials traceability. PNG will be in a better position to determine the cost savings, and avoided costs once all of these processes have been defined and implemented across the organization by the end of 2020.

Unlike the GIS project implementation that will be complete by the end of 2020, there is considerable work to be completed on the ARM project beyond 2020. As a result, PNG will not be in a position to quantify cost savings (cost avoidance) associated with the project in 2020. It is important to note, that although there is expected to be work flow efficiency related improvements with the completion of the ARM initiative, the project is primarily compliance driven and any financial opportunity is more likely to be realized by cost avoidance associated with incidents and orders resulting from incomplete, inaccurate, and/or unavailable records.

84.2 Please quantify the dollar impact from the increased pressures PNG expects from the engineering projects critical to PNG's ongoing compliance with heightened industry standards and pipeline regulations.

Response:

The upward cost and resource pressures PNG is experiencing as a direct result of the continuous improvement needed to maintain compliance with heightened industry standards, pipeline regulations, and regulator, public, and stakeholder expectations has been integral to a significant number of information request responses within this package and has been an evident and defended recurring theme throughout.

The following list provides some (but not all) of the associated information request responses from which the overall quantification (magnitude) of cost impact can be understood.

- Question 10.0 to 15.0
- Question 38.0
- Question 47.0 to 49.0
- Question 55.0 / 56.0 / 59.0
- Question 63.0
- Question 65.0

84.3 Please provide anticipated avoided costs for staff or contract resources that would otherwise be required to create and manage information most appropriately retained in a GIS. Please include supporting calculations.

Response:

Please see the response to Question 84.1.

84.3.1 Please identify any other ways that the GIS system will enable PNG to address engineering projects in a cost-effective manage and discuss whether these benefits can be quantified. If not, please discuss why not.

Response:

PNG has identified a number of areas where its GIS system can contribute to increased system reliability and security, improved staff and contractor productivity, and more efficient regulatory processes. PNG has identified these on pages 161 to 163 of the Amended Application. Also as stated on page 163 of the Amended Application, PNG anticipates increased pressure on its operating costs related to engineering projects critical to PNG's ongoing compliance with heightened industry standards and pipeline-related regulations. Effective use of technology, such as the GIS, will help PNG avoid undue costs associated with heightened compliance requirements.

As stated in the response to Question 84.1, PNG expects to be in a position at the end of 2020 to determine the nature of the avoided activities and associated avoided costs.

Lastly on page 163, PNG states:

> …ARM project will result in the increased reliability of recalled information, will help minimize opportunity for error, will reduce risk associated with legacy information and assets, will improve emergency response performance, will provide step change to the reconciliation of pipeline system records between PNG and technical regulators, and will provide a foundational piece for improved system integrity management and management of change. It can easily be argued that each of these individual benefits, along with their aggregate sum, provide significant cost savings through the lifetime of an operating asset by affecting incremental step change in work efficiency, risk management, and incident avoidance.

84.4 Please provide the expected annual cost savings for each individual benefit noted above and the aggregate sum of benefits from the ARM project.

Response:

While the listed benefits are expected to provide cost savings and realized cost avoidance opportunity through the lifetime of an operating asset, this cost related benefit to the ARM project is secondary to the fact that the project is compliance based. As a result, efforts have not been made to quantify annual cost related benefits to the provided list of compliance requirements and operational improvements.

While PNG believes it is important to identify the expected (and secondary) benefits to the ARM initiative, it must be reinforced that this project was and continues to be pursued and justified for compliance purposes. As per CSA Z662-19, the effective management and retention of accurate, complete, verifiable, and retrievable pipeline system asset records is required under:

- Section 3 Safety and Loss Management – Sub-section 3.1.2e) – Document and Record Management
- Section 4 Design – Sub-section 4.1.11 – Design Document and Record Management
- Section 5 Materials – Sub-section 5.7 Records of Materials
- Section 10 Operation, Maintenance, and Upgrading – Sub-section 10.4 Records (most notably 10.4.2 Pipeline Systems)
- Annex A – Section A.6.3 Control of Records
- Annex N – Section N.1.5 Integrity Management Program Records
- Annex N – Section N.2.5 Facility Management Program Records

85.0 Reference: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.7, p. 171
Automotive Cost Allocation – Evaluation of Historic Allocation Methodology - Capital

On page 171 of the Amended Application, PNG states that "Allocating Automotive costs based solely on labour hours has not achieved optimal results for all divisions."

Further on the same page PNG states it completed a test of the reasonableness of the historic approach for the allocation of forecast and actual Automotive costs to capital and prepared the following summary to illustrate recent experience with over (under) allocations to capital.

Automotive - Capital Cost Over (Under) Allocation ($)	2015	2016	2017	2018	2019	Total	Average
Historic Divisional Allocation Methodology							
PNG-West	(1,511)	23,423	3,176	(24,008)	(46,530)	(45,450)	(9,090)
FSJ/DC	1,052	23,460	6,601	7,873	20,943	59,929	11,986
TR	(122)	(3,482)	(1,071)	(252)	(345)	(5,272)	(1,054)
	(581)	43,401	8,706	(16,387)	(25,932)	9,207	1,841

Based on these results PNG states on page 171:

> As can be seen from the data presented, the historical allocation methodology for capital has resulted in over (under) allocations in the range of ± $122 to $46,530 over
>
> the past five years, however, based on the five-year average, allocations have fallen within a reasonably narrow range of ± $1,054 to $11,986 during this period.
>
> Given this narrow range in over (under) allocation, PNG is satisfied that it is appropriate to continue with the current budgetary conventions it has in place for forecasting and allocating Automotive costs to capital.

85.1 Based on the summary, please explain why there appears to be a consistent over allocation of Automotive costs to the FSJ/DC division and under allocation to the PNG-West and TR divisions in 2018 and 2019.

Response:

The consistent over allocation of Automotive costs to FSJ/DC and the under allocation to PNG-West and TR in 2018 and 2019 for rate setting purposes suggests that there is a pattern of over forecasting of capital labour hours for FSJ/DC and an under forecasting of capital labour hours for PNG-West and TR. PNG submits that the very nature of its operations, whereby there is an ongoing need to make decisions and assessments on deploying employees on capital versus operating activities, will result in actual variances from forecast. PNG routinely reviews its operating and capital forecasting activities to eliminate the potential for such patterns.

85.2 Please confirm, or explain otherwise, that forecasting and allocating Automotive costs to capital is based on labour costs.

Response:

PNG forecasts the elements in its pool of consolidated Automotive costs (insurance, fuel and maintenance) based on recent cost experience not labour costs. PNG confirms that it allocates it Automotive cost pool to capital projects based on labour costs.

85.2.1 If confirmed, please discuss why allocating Automotive costs to capital based solely on labour is appropriate given the over/under allocation in the recent actual results.

Response:

As noted in the Amended Application, as a budgeting convention, PNG has traditionally allocated its consolidated forecast Automotive cost to the PNG-West and PNG(NE) divisions on a prorata basis, among divisions, based on forecast operating labour for employees who are assigned a vehicle and capital labour costs for each division.

In 2013, PNG reviewed the 15 percent factor applied to capital labour for the allocation of Automotive costs to capital and confirmed that it was a reasonable approximation of actual Automotive costs attributable to capital.

86.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.7, pp. 172-173
Automotive Cost Allocation – Proposed Automotive Cost Allocation

On pages 172 and 173 of the Amended Application, PNG states:

> The average divisional allocation of forecast costs for 2015 to 2019 was: 60% PNG-West; 35% FSJ/DC; and 5% TR. The actual divisional allocation of costs for 2015 to 2019 were distributed: 66% PNG-West; 32% FSJ/DC; and 2% TR.
>
> As a test of using historic results to predict future costs, PNG recast the forecast operating Automotive costs for 2015 to 2019 using the five-year actual average percentage distributions noted. This proposed allocation methodology for operating expense reduces the range of over (under) allocations for the past five years to ± $176 to $28,479, considerably lower than the forecast error of the historic methodology. Further, the bias for over allocating Automotive costs to PNG(NE) has dissipated. These results

Automotive - Operating Cost Over (Under) Allocation ($)	2015	2016	2017	2018	2019
Proposed Divisional Allocation Methodology					
PNG-West	(10,122)	(9,414)	28,479	(2,103)	(6,839)
FSJ/DC	8,418	1,587	(24,116)	7,096	7,015
TR	1,704	7,827	(4,363)	(4,992)	(176)
	0	-	0	(0)	0
Improvement From Historic Methodology					
PNG-West	(43,522)	(45,517)	(40,157)	(46,278)	(48,577)
FSJ/DC	26,323	27,529	24,287	27,989	29,380
TR	17,199	17,988	15,869	18,288	19,197
	(0)	(0)	(0)	(0)	(0)

> are presented in the table that follows.

86.1 Please provide the total and five-year average of each division's percentage distribution of operating Automotive costs.

Response:

Please see the table that follows for the average of each division's percentage distribution of actual operating Automotive costs.

	2015	2016	2017	2018	2019	Average %
Operating						
PNG-West	67%	67%	62%	66%	67%	66%
FSJ/DC	30%	31%	35%	31%	31%	32%
TR	2%	1%	3%	3%	3%	3%
	100%	100%	100%	100%	100%	100%

86.2 Please explain the difference in allocation methodology between the "Proposed Divisional Allocation Methodology" and "Improvement from Historic Methodology" as presented in the above table.

Response:

PNG clarifies that there is only one proposed allocation methodology, as per the Amended Application, resulting in the noted illustrative variances in actual costs from the forecast allocation. The allocation methodology for the "Proposed Divisional Allocation Methodology" is as proposed in the analysis included in the Amended Application. The table titled "Improvement from Historic Methodology" is simply the difference between the historic allocation methodology and the methodology proposed in the Amended Application.

For clarity, please see the table that follows which illustrates the over (under) allocation of Automotive costs as per the historic methodology and the over (under) allocation of Automotive costs as per the proposed methodology, with the "Improvement from Historic Methodology" being the difference, i.e. improvement, under the proposed methodology compared to the historic allocation methodology.

Automotive - Operating Cost Over (Under) Allocation ($)	2015	2016	2017	2018	2019
Historic Divisional Allocation Methodology					
PNG-West	(53,644)	(54,931)	(11,678)	(48,381)	(55,416)
FSJ/DC	34,741	29,116	171	35,085	36,395
TR	18,903	25,815	11,507	13,296	19,021
	(0)	(0)	(0)	(0)	(0)
Proposed Divisional Allocation Methodology					
PNG-West	(10,122)	(9,414)	28,479	(2,103)	(6,839)
FSJ/DC	8,418	1,587	(24,116)	7,096	7,015
TR	1,704	7,827	(4,363)	(4,992)	(176)
	0	-	0	(0)	0
Improvement From Historic Methodology					
PNG-West	(43,522)	(45,517)	(40,157)	(46,278)	(48,577)
FSJ/DC	26,323	27,529	24,287	27,989	29,380
TR	17,199	17,988	15,869	18,288	19,197
	(0)	(0)	(0)	(0)	(0)

87.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.7, pp. 173.
Automotive Cost Allocation – Recommendations – Capital Allocation

On page 173 of the Amended Application, PNG states:

> Continue to apply the current administrative convention of allocating actual Automotive costs to capital, whereby a 15% factor is applied to capital labour costs and capitalized.

87.1 Please explain what the 15 percent factor used in the allocation of actual capital Automotive costs is based on.

Response:

The 15 percent factor is effectively a vehicle overhead capitalization rate. This factor has been in place for many years and the genesis is unknown, but believed to be based on some historic study or evaluation of actual experience. As noted in response to Question 85.2.1, a review of the 15 percent factor was undertaken to assess its validity and it was confirmed that it was a reasonable approximation of actual Automotive costs attributable to capital activities.

87.2 Please discuss the results of the over (under) allocations to capital if the overhead capitalization rates were applied.

Response:

PNG is unclear of the reference to "the overhead capitalization rates". Transfers to capital (capitalized overhead) is addressed in Section 2.6 of the Amended Application. And while PNG presents overhead capitalization rates for each year in Table 27, these are computed values rather than applied values. That is to say, PNG does not apply these rates to capitalized overhead, the rates fall out of the methodology PNG makes use of to capitalize overheads.

Further, as noted in response to Question 87.1, the 15 percent factor can be considered to be a vehicle overhead capitalization rate and that this rate has some historic basis.

88.0 REFERENCE: OTHER MATTER TO BE ADDRESSED FROM PRIOR YEAR DECISIONS
Exhibit B-2, Section 3.4.1.7, p. 174
Automotive Cost Allocation – Proposed Forecasting of Consolidated Automotive Cost Pool

On page 174 of the Amended Application, PNG states:

> …in consideration that historic costs may be reflective and predictive of future costs, PNG analysed historic results and, setting 2015 as a base year, applied an inflation factor of 2% to each year in forecasting the subsequent year's costs. PNG compared the forecasts using this inflationary approach with actual costs and found that though there continued to be a consistent over forecast in amounts, the range decreased to $5,970 to $137,085 and the average decreased to approximately $57,000 on a consolidated basis.

Further on page 174 of the Amended Application PNG presents the following table summarizing its historic and proposed methodology for forecasting the consolidated pool of

Automotive - Consolidated Cost Pool Over (Under) Budget ($)	2015	2016	2017	2018	2019	Total	Average
Historic Forecast Methodology							
Forecast	929,151	1,063,615	1,085,120	1,034,019	1,053,535	5,165,440	1,033,088
Actual	862,306	884,078	829,604	980,052	995,720	4,551,760	910,352
	66,845	179,537	255,516	53,967	57,815	613,680	122,736
Proposed Methodology							
Forecast	929,151	947,734	966,689	986,022	1,005,743	4,835,339	967,068
Actual	862,306	884,078	829,604	980,052	995,720	4,551,760	910,352
	66,845	63,656	137,085	5,970	10,023	283,579	56,716
Improvement In Forecasting	-	115,881	118,431	47,997	47,792	330,101	66,020

Automotive costs.

88.1 Please explain why 2015 was selected at the base year.

Response:

As a convention for its analysis of the Automotive cost allocation methodology, PNG selected the period of 2015 to 2019 as the evaluation period. Furthermore, in many of PNG's budgeting activities, forecast amounts are based on prior year averages of actual costs, often for the most recent 5-year period.

In this instance, in testing an inflationary approach to forecasting the Automotive cost pool, for consistency PNG selected the beginning of this test period as the base year.

88.2 Please re-create the above table to adjust the proposed methodology by using the 2015 actual, rather than forecast, as the base and applying the inflation factor to actual costs for subsequent years.

Response:

Please see the table that follows. In the table the proposed methodology uses 2015 Actual costs as the base for 2016 Forecast costs with each year thereafter inflated by 2%. As 2015 is the base year the table has been adjusted to remove the effects of 2015 variances.

Automotive - Consolidated Cost Pool Over (Under) Budget ($)	2015	2016	2017	2018	2019	Total (2016-2019)	Average
Historic Forecast Methodology							
Forecast	-	1,063,615	1,085,120	1,034,019	1,053,535	4,236,289	1,059,072
Actual	-	884,078	829,604	980,052	995,720	3,689,454	922,364
	-	179,537	255,516	53,967	57,815	546,835	136,709
Proposed Methodology							
Forecast	862,306	879,552	897,143	915,086	933,388	3,625,169	906,292
Actual	862,306	884,078	829,604	980,052	995,720	3,689,454	922,364
	-	(4,526)	67,539	(64,966)	(62,332)	(64,285)	(16,071)
Absolute Improvement In Forecasting (net +/-)	n/a	175,011	187,977	(10,999)	(4,517)	482,550	120,638

PNG observes that making use of 2015 Actual costs lends further supports to using an inflationary approach based on actual costs, and notes that the range of variances under this revised approach Forecast amounts ranged from being $64,966 lower than Actual to $67,539 greater that Actual with an average Forecast amount $16,071 less than Actual, much more appropriate than the average Forecast amount being $136,709 greater than Actual per the historic methodology.

Further on the same page PNG states:

> PNG recommends that the consolidated Automotive cost pool for Test Year 2020 be forecast based on forecast 2019 actual costs with a 2% provision for inflation. PNG has reflected this recommendation in this Application. Test Year 2021 costs have been forecast at the Test Year 2020 amount inflated by 2% for inflation.

88.3 Please explain what is meant by "forecast 2019 actual costs."

Response:

PNG prepared this analysis using 2019 Actual data to the end of October 2019 and forecast costs for the months of November and December 2019 to come up the a calendar year projection of actual costs for 2019. A more appropriate description would be "forecast 2019 costs."

88.4 Please comment on the strengths and weaknesses of using historic allocations of Automotive costs as a predictor of future allocations for the operating and consolidated forecast.

Response:

PNG has proposed to make use of historic actual distributions of Automotive costs as a basis for future cost allocations.

PNG appreciates that such an approach has weaknesses, particularly in times of rapid change in nature and levels of business activity. However, PNG observes that as a utility with relatively stable and static (i.e. not very dynamic) operations such an approach has merit in its simplicity both in terms of transparency and administrative requirements.

88.5 Please explain why a five-year actual average was selected for the allocation of operating costs and consolidated forecast costs.

Response:

As noted in response to Question 88.1, as a convention for its analysis of the Automotive cost allocation methodology, PNG selected the period of 2015 to 2019 as the evaluation period. This was done as, in many of PNG's budgeting activities, forecast amounts are based on prior year averages of actual costs, often for the most recent 5-year period.

88.6 Please explain whether PNG considered creating a forecast Automotive cost for each division based on expected costs. Please comment on the pros and cons of this approach and why it was not selected.

Response:

In the past, PNG has considered alternatives for forecasting Automotive costs, including divisional forecasts. However, in PNG's experience the pooled approach to forecasting Automotive costs was found to be administratively efficient as it aligns with the way PNG manages it procurement of vehicles and Automotive cost elements – on a consolidated basis.

P. OTHER DIRECTIVES

89.0 Reference OTHER DIRECTIVES
Exhibit B-2, Appendix C, p. 3
Business Risk Assessment

On page 3 in Appendix C of the Amended Application PNG filed an updated business risk assessment based on the consolidated entity for PNG-West and PNG(NE) (collectively PNG).

Page 3 of Appendix C states:

> Given PNG's smaller size and resources, the numerous requirements for dealing with various aspects of Indigenous Rights represent a much more resource intensive effort. The assessment of this risk continues to remain consistent with that made in 2018, but with an increasing trend given recent court cases and the recent introduction of UNDRIP legislation.

89.1 Please comment on how the recent introduction of UNDRIP will impact PNG operations over the Test Period and any plans PNG has in place to address the impact.

Response:

PNG's service territory covers a very large geographic area spanning the traditional territories of many Indigenous Nations, mostly involving the rights of way for our pipelines, allowing us to serve our many communities, including Indigenous communities. PNG has established and maintains relationships with these communities on an ongoing basis and the UNDRIP reinforces the need to maintain and strengthen those relationships.

Because of our significant geographic coverage, this requires a concerted effort by our field-level staff, which will require increasingly more time and attention, particularly as PNG prepares to execute its ongoing maintenance work and the reactivation work required for the anticipated RECAP volumes.

PNG will utilize its local field staff with support from various Indigenous Nations consultants and subject matter experts as required.