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March 21, 2018

Sent via eFile

PNG WEST 2018-2019 REVENUE REQUIREMENTS
EXHIBIT A-6

Ms. Janet P. Kennedy
Vice President, Regulatory Affairs and Gas Supply
Pacific Northern Gas Ltd.
#950 - 1185 West Georgia Street
Vancouver, BC V6E 4E6
jkennedy@png.ca; votto@png.ca

Re: Pacific Northern Gas Ltd. – 2018-2019 Revenue Requirements Application – Project Number 1598935 – Information Request No. 1

Dear Ms. Kennedy:

Further to your filing of the 2018-2019 Revenue Requirements Application dated November 30, 2017, please find enclosed British Columbia Utilities Commission Information Request No. 1. Please file your responses electronically by April 12, 2018.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/yl

Enclosure

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Pacific Northern Gas Ltd.
2018–2019 Revenue Requirements Application

INFORMATION REQUEST NO. 1 TO PNG

Table of Contents **Page no.**

A. DEMAND FORECAST REVENUES AND MARGIN

1.0 **Reference: DEMAND FORECAST REVENUES AND MARGIN**
Exhibit B-1-1, pp. 7, 10
Proposed rate deferral mechanism

Pacific Northern Gas Ltd. (PNG) seeks approval in the Amended Application to create a short term interest bearing rate deferral account in 2018, to levelize the impact of the combined net revenue deficiencies for 2018 and 2019, to be fully amortized in 2019.

1.1 Please explain why PNG has proposed a short term interest rate for the rate deferral account.

1.2 Please describe any alternatives to the proposed rate deferral account that were considered by PNG in order to address rate volatility between 2018 and 2019.

2.0 **Reference: DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.1, pp. 25-28
Commercial deliveries and margin

On page 27 of Exhibit B-1-1, PNG states: "[…]forecast gas deliveries for 2017 included a provision for the supply of camp gas for a liquefied natural gas project to be situated in Kitimat. This project has been delayed therefore no volumes have been included in the 2018 and 2019 forecast amounts."

"The commercial transport group, consisting of Small Commercial Transport (RS22) and Large Commercial Transport (RS24), has increased by approximately 3,000 GJ compared to Decision 2017."

2.1 Please provide a volume breakdown clearly showing the effects on demand caused by the reclassification of small and large commercial sales customers, and the forecast demand increase attributed to existing small and large commercial customers.

2.1.1 Please explain why deliveries for large commercial transport customers increases by 9,000 GJ between 2017 and 2018, and decreases by 3,500 GJ between 2018 and 2019.

2.2 Please explain the main reasons for the increase of approximately 43,000 GJ in small commercial firm demand.

2.3 Under which sales class does the liquefied natural gas project in Kitimat fall? Please provide the associated volume decrease for this project in Test Year 2018 as compared to Decision 2017.

2.3.1 Could this project come online prior to 2019? How would this affect forecast gas deliveries?

2.4 Please confirm that the increased demand in the commercial transport group demand consists of Small Commercial Transport (RS22) and Large Commercial Transport (RS33), as detailed in Table 9: Forecast Gas Deliveries, as opposed to RS 22 and RS 24, as indicated on page 27 of the Amended Application.

2.5 Please account for the variance in demand between 2017 Actual deliveries and 2017 Decision deliveries for Large Commercial Firm (Rate 3) customers.

3.0 **Reference: DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.1, pp. 25-28
Seasonal Off Peak/NGV Deliveries

3.1 Please explain the cause of the variance in Seasonal Off-Peak Deliveries in 2017 Actual as compared to Decision 2017.

3.1.1 Please explain if the variance between Actual 2017 and Decision 2017 deliveries for NGV is related to the single company that is no longer selling or using compressed natural gas, as described on page 27 of the Amended Application. If this is related to other factors, please explain.

4.0 **Reference: DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.1, pp. 25-28
Industrial deliveries

On page 28 of Exhibit B-1-1, PNG states: "The Small Industrial Transport class demand is forecast to decrease by 3,000 GJ in 2018 compared to Decision 2017, and 2019 reflects a further decrease from 2018 of approximately 40,000 GJ. These forecasts reflect responses from PNG-West's annual customer surveys."

4.1 Did PNG consult with all Small Industrial Transport customers?

4.1.1 Please provide the number of surveys conducted, and the number of responses PNG received. How many responses were received relative to the number of customers?

4.2 Please discuss the main reasons for the decrease of 40,000 GJ from 2018 to 2019.

4.3 What is the likelihood that customers could increase demand throughout the year?

4.3.1 Are customers required to provide PNG with an adequate lead time before additional demand is required? If so, what lead time is required?

4.4 Please provide the annual demand volumes associated with each of the new pellet plant in Smithers, BC, and Ridley Island Propane Export Terminal (RIPET), a small industrial customer, for Test Year 2019.

4.5 Please explain the reasons for the Small Industrial Sales (Rate 4) variance in deliveries in Actual 2017 as compared to Decision 2017.

4.5.1 Why is the forecast for Small Industrial Sales (Rate 4) customers for 2018 test year deliveries below 2017 actual deliveries when there is an anticipated 52,000 GJ increase due to the Smithers pellet plant? Please elaborate.

On page 28 of the Amended Application, PNG states: "For Test Year 2018, Rio Tinto Alcan (RTA) has indicated a decrease in forecast deliveries that are in line with recent historical usage, and has provided PNG-West with a notice to reduce their contract demand by 10% temporarily for the period November 2018 to October 2019."

4.6 Table 9: Forecast deliveries shows that since 2013, actual RTA deliveries have increased year over year. What period is PNG referring to that indicates a decrease in forecast deliveries in line with recent historical usage?

4.7 Please provide calculation details clearly explaining how the increase in T-South heating value change from 39.0 MJ per m^3 to 40.0 MJ per m^3 results in approximately 40,200 GJ and $121,000 in Test Year 2018 deliveries.

4.7.1 Assuming the T-South heating value remained the same, what effect would the reduction in RTA demand have on deliveries and margin between 2017 Decision and Test Year 2018 Deliveries?

4.8 Please provide the annual demand from which PNG calculated the RTA demand reduction of 99,144 GJ between Test Years 2018 and 2019, relating to the period January to October.

Page 28 of Exhibit B-1-1 states: "The BC Hydro deliveries forecast is based on the assumption BC Hydro will be operating 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"

4.9 BC Hydro deliveries have ranged from 20,800 GJ to 136,550 GJ for the period 2013 actuals to 2017 Decision, indicating BC Hydro operated this generation facility more frequently in some years. Please explain how this figure of 24,000 GJ is consistent with historical deliveries.

4.10 Over which historic period did PNG use to calculate this 24,000 GJ demand?

4.11 Which years are consistent with the period that BC Hydro operated its generation station as a backup facility? Which are not?

4.12 Where demand is greater than 24,000 GJ, did BC Hydro operate its generating station differently than on a standby basis? What is the frequency that this generation station was in operation in those years?

4.13 What is the probability that BC Hydro's annual demand profile for Prince Rupert generating station will be greater than 24,000 GJ in 2018 and 2019?

4.14 Please confirm, or explain otherwise that PNG-West contacted BC Hydro to obtain feedback on how it plans to operate the generation facility.

4.15 Did BC Hydro confirm they would continue to operate Prince Rupert as a backup facility? Please discuss.

4.15.1 How does PNG-West ensure that there is sufficient capacity to meet BC Hydro's demand if Prince Rupert is operated on a basis other than a backup facility? Please explain.

5.0 **Reference: DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.2, pp. 28-31
Company use gas requirements

On page 30 of Exhibit B-1-1, PNG states: "The components of the company use gas such as Station Heating, Office and Shop Heating, In House Consumption and Blowdown -Operating tend to be fairly consistent with Decision 2017, the exception being an increase in compressor fuel."

5.1 Please explain the increase of 17.3 percent and 8.7 percent in compressor fuel for the years 2018 and 2019 respectively?

5.1.1 How is the usage of compressor fuel correlated to total deliveries?

5.2 Why is company gas use for compressor heating lower between 2017 Decision and Test Year 2018, but higher in Test Year 2019 when there is an increase in total deliveries year over year during the same period?

5.3 Is office and shop heating correlated with total deliveries? If yes, please explain why. If not, please explain how these requirements are calculated.

B. OPERATING AND MAINTENANCE EXPENSES

6.0 **Reference: OPERATING AND MAINTENANCE EXPENSES**
Exhibit B-1-1, pp. 34
Investigative digs and repairs

On page 34 of its Application PNG states that for "For Test Year 2018, the forecast expenditure for investigative dig activity is $511,000, comparable to $500,000 forecast under Decision 2017."

6.1 Please provide the Actual 2017 investigative digs and repairs expense and explain any variance between Test Year 2018 and Actual 2017.

7.0 **Reference: Operating Expenses**
Exhibit B-1-1, Sections 2.3.1 and 3.2.2.1, pp. 33-34 and pp. 126-127;
PNG-West 2016-2017 Revenue Requirements Application (RRA) proceeding,
Exhibit B-4, BCUC IR Nos. 8.1 and 8.2
Account 665 – Pipelines

On page 127 PNG states:

> The actual costs for 2017 included in this account are $107,000 or 5.5% greater than those approved under Decision 2017. This is primarily due to regular labour incurred for temporary line repairs as a result of the Kleanza Creek and Copper River washouts in late 2017, and to contractor charges incurred for the review and update of procedures associated with integrity management planning.

7.1 Please confirm that costs related to: (i) the temporary line repairs as a result of the Kleanza Creek and Copper River washouts; and (ii) the integrity management planning are not forecast to occur in Test Years 2018 and 2019.

7.1.1 If not confirmed, please explain, and provide the total forecast cost for this account related to: (i) and (ii) above and a breakdown of the amounts by test year.

On page 33 PNG states:

> The In-Line Inspection (ILI) program is a key component of PNG's pipeline integrity management plan and is primarily based on running two types of tools, a Magnetic Flux Leakage (MFL) tool that is primarily used to detect metal loss due to external and internal corrosion, and a caliper tool used to detect deformities such as dents and ovality.

7.2 Please confirm that PNG's planned integrity management activities and forecast expenditures for Test Years 2018 and 2019 align with the integrity management plan submitted to the Oil and Gas Commission. If not confirmed, please explain.

In response to BCUC IR 1.8.1 in the PNG 2016-2017 RRA proceeding, PNG provided the following table:

PNG-West BCUC 665 – Pipelines					
	Test Year 2017	Test Year 2016	Actual 2015	Decision 2015	Actual 2014
In-line Inspections/Pigging	134,000	183,000	153,000	210,000	188,000
Close Interval Surveys (CIS)	16,000	54,000	25,000	35,000	51,000
Investigative Digs	500,000	489,000	467,000	488,000	539,000
ROW Clearing	311,000	305,000	276,000	299,000	157,000
SCADA	345,000	338,000	350,000	332,000	425,000
Pipeline Patrols	44,000	43,000	52,000	42,000	40,000
High Pressure Risk Assessment Methodology	n/a	51,000	n/a	n/a	n/a
Airborne Laser Methane Assessment	104,000	n/a	n/a	n/a	n/a
Other	343,000	336,000	351,000	308,000	47,000
Total	$1,797,000	$1,799,000	$1,674,000	$1,714,000	$1,447,000

7.3 Please provide a similar table as the above for the following years: Actual 2016, Decision 2016, Actual 2017, Decision 2017 and Test Years 2018 and 2019.

7.4 Please provide explanations for any variances greater than $50,000 or 10 percent compared to the previous year actual or the Decision, if not already provided on pages 33-34 of the Amended Application.

In response to BCUC IR 1.8.2 in the PNG- 2016 RRA proceeding, PNG provided the following table:

	2017 Test Year	2016 Test Year	2015 Decision
BCR Crossing Fees	17,000	17,000	16,000
Cathodic Protection System	38,000	34,000	30,000
Depth Cover River Crossing Survey	11,000	11,000	13,000
Drafting	6,000	6,000	4,000
Line Locates	13,000	13,000	13,000
Tool & Equipment Repairs/Mtnc	30,000	29,000	31,000
Warehousing	79,000	77,000	45,000
Porpoise Dive Inspections	5,000	5,000	7,000
Inspecting/Operating Above Ground Structures (i.e. bridges, valves)	66,000	63,000	64,000
Unallocated Const & Misc Shop Expenses	53,000	51,000	56,000
Other	25,000	30,000	29,000
Total	343,000	336,000	308,000

7.5 Please provide the same breakdown for the "Other" category of expenses in Account 665 for: Decision 2016, Decision 2017, Test Years 2018 and 2019 and actuals for 2016 and 2017 (if available).

8.0 **Reference: Operating Expenses**
Exhibit B-1-1, Sections 2.3.2, 3.2.1.1 and 3.2.2.1, pp. 34-35, 119-120 and pp. 126-127
Account 666 – Compressors

On page 120 PNG states:

> The actual costs for 2016 included in this account are $96,000 or 19.0% greater than those approved under Decision 2016. This is primarily due to labour and contractor costs being over budget amounts due to service and repair of relief valve and to operations supplies showing as being over budget due to the incorrect recording of R1 odorant purchase to this account when the budget amount was provided for in Account 675.

On page 127 PNG states:

> The actual costs for 2017 included in this account are $135,000 or 31.7% greater than those approved under Decision 2017. This is primarily due to greater than forecast labour costs due to the pending retirement of a compression station operator and to unplanned costs for relief valve overhauls following a regulatory inspection.

On page 34 PNG states:

> Forecast Test Year 2018 costs of $480,000 are $56,000 or 13.1% higher than Decision 2017. This increase is primarily due to greater contractor charges for relief valve testing work, as well as increased utility, materials and labour costs.

8.1 Please discuss if the amount of relief value work forecast for Test Years 2018 and 2019 is expected to be greater, lower or the same as the 2016 and 2017 actuals.

8.2 Please confirm that the relief valve testing work is expected to continue for the entirety of 2018 and 2019. If so, please clarify when this work is expected to be completed. If not confirmed, please explain.

8.3 Please discuss if PNG considered tendering the work. If not, please explain why not.

8.4 Please provide a comparison between the 2016 and 2017 actual costs, and 2018 and 2019 forecast costs for contractor charges, materials and labour for relief valve testing work.

Costs	2016Actual	2018 Actual	Test Year 2018	Test Year 2019
contractor charges				
materials				
labour				

8.4.1 If known please provide an explanation as to why the contractor charges have increased.

8.5 Please clarify how the pending retirement of a compression station operator caused labour costs to be greater than forecast in 2017.

8.6 When did the compression station operator retire or is expected to retire?

8.7 How many compression station operators were there in 2016 and 2017 and how many are forecast for Test Years 2018 and 2019?

9.0 **Reference: Operating Expenses**
Exhibit B-1-1, Section 2.3.5, pp. 35-36; PNG-West 2016-2017 RRA proceeding,
Exhibit B-4, BCUC IR Nos. 11.1 and 11.6
Account 685 – General Operations

On page 35 PNG states:

> Test Year 2018 expenditures of $2.801 million are forecast to increase by approximately $383,000 or 15.8% over Decision 2017. Factors contributing to this increase include: additional engineering projects including digital data mapping and the implementation of a geographical information system; increased labour costs attributable to new positions in the areas of engineering and records management; asset management system licensing costs, and inflation. These aforementioned activities are critical to addressing ongoing compliance to pipeline integrity related regulations, moving PNG-West from paper-based systems to digital systems, and progressing PNG-West to more contemporary industry standards.

9.1 Please discuss when each of the activities mentioned in the preamble above is expected to begin and be completed.

9.1.1 Please provide the total cost of each of these activities broken down by test year.

9.1.2 Please explain how the costs associated with each of these activities are different from the costs under Capital Expenditures related to the same projects.

9.2 Please discuss when the new positions in the areas of engineering and records management is expected to begin, and the forecast cost of each position.

9.2.1 Please discuss if any of these new positions will be replacing current positions (i.e. certain tasks currently performed may no longer be required or are redundant once PNG moves to a digital system).

9.2.1.1 If so, please quantify the cost savings from the positions that will no longer be required, and explain in which account and test year(s) these forecast savings have been recorded.

On page 36 PNG states:

> The two largest components of the $99,000 increase in forecast costs from Test Year 2018 to Test Year 2019 are a labour increase due to provision for a three-month handover on an anticipated retirement in shipping/receiving, and an increase in the vehicle cost allocation to operations due to lower planned capital expenditures.

9.3 Please provide a breakdown of the $99,000 forecast increase for Test Year 2018.

9.4 Please explain in detail why the vehicle cost allocation to operations has increased.

In response to BCUC IR 1.11.1 in the PNG2016-2017 RRA proceeding, PNG provided the following table:

Account 685 - General Operations ($'s)	Test Year 2017	Test Year 2016	Actual 2015	Decision 2015	Actual 2014	NSP 2014	Actual 2013	Decision 2013	Actual 2012	Decision 2012	Actual 2011	NSP 2011
Auto	597,015	589,191	485,315	503,244	596,385	515,483	571,654	501,568	74,673	69,744	90,785	73,134
Contractors & consulting fees	149,616	146,682	142,814	152,286	184,090	171,419	144,427	154,948	160,444	147,623	168,579	132,486
Labour (incl bonus)	1,946,684	1,900,772	1,925,858	1,841,658	1,567,373	1,608,416	1,619,083	1,567,646	1,555,527	1,535,028	1,531,380	1,523,371
Licenses & Permits	108,451	106,325	89,725	98,940	97,453	105,264	101,299	113,021	97,855	99,709	96,805	81,861
Materials	22,700	22,255	35,621	21,349	52,700	21,224	33,869	19,904	40,765	19,437	23,211	26,601
Office Supplies & Postage	38,173	37,425	40,945	35,543	39,660	38,252	32,398	41,204	31,431	38,021	42,127	38,613
Phone	111,553	109,365	18,038	16,116	14,435	16,399	17,034	19,402	17,420	19,428	18,373	20,000
Leased Office Equipment	20,290	19,892	17,656	19,992	14,455	17,881	8,340	12,309	8,301	14,407	10,638	7,342
Other (<$10,000)	28,448	27,889	54,196	27,893	29,898	30,257	34,939	25,559	30,167	38,265	41,142	24,646
Travel & Subsistence	122,487	120,084	145,816	113,150	105,514	109,981	130,724	99,677	123,879	89,010	105,044	91,813
Utilities	24,408	23,929	24,027	23,460	22,688	23,460	22,184	20,397	22,629	17,383	21,901	15,849
	3,169,825	3,103,809	2,980,011	2,853,631	2,724,651	2,658,036	2,715,951	2,575,635	2,163,091	2,088,055	2,149,985	2,035,716
Shared Service Cost Recovery from PNG(NE)	(743,000)	(746,000)	(691,000)	(691,000)	(625,000)	(625,000)	(632,000)	(632,000)	(642,000)	(642,000)	(571,000)	(571,000)
	2,426,825	2,357,809	2,289,011	2,162,631	2,099,651	2,033,036	2,083,951	1,943,635	1,521,091	1,446,055	1,578,985	1,464,716

9.5 Please provide a similar table for Actual 2016 and 2017, Decision 2016 and 2017 and Test Years 2018 and 2019.

9.6 Please provide explanations for any variances greater than $50,000 or 10 percent compared to the previous year actual or forecast.

In response to BCUC IR 1.11.6a in the PNG 2016-2017 RRA proceeding, PNG provided the following table:

Operating Labour Account and Description ($'s)	Test Year 2017	Change	Test Year 2016	Change	Decision 2015	Change	Actual 2015
660 Supervision	52,566	1,202	51,364	1,174	50,190	(66,291)	116,481
664 Communications	603	13	590	14	576	(3,091)	3,667
665 Pipelines	665,542	14,442	651,100	61,114	589,986	33,970	556,016
666 Compressors	282,104	6,450	275,654	76,427	199,227	(5,624)	204,851
667 Regulating stations	136,439	3,120	133,319	3,983	129,336	(24,231)	153,567
Total transmission	**1,137,254**	**25,227**	**1,112,027**	**142,712**	**969,315**	**(65,267)**	**1,034,582**
670 Supervision	321,119	7,342	313,777	27,132	286,645	(123,512)	410,157
673 Removing & resetting meters	375,471	8,585	366,886	3,819	363,067	43,820	319,247
674 Service on customer premises	63,967	1,463	62,504	259	62,245	10,251	51,994
675 Mains and services	289,409	7,280	282,129	17,612	264,517	(56,261)	320,778
677 Regulating stations	6,487	148	6,339	145	6,194	2,650	3,544
Total distribution	**1,056,453**	**24,818**	**1,031,635**	**48,967**	**982,668**	**(123,052)**	**1,105,720**
684 Communications	322	8	314	7	307	(20)	327
685 General systems operations	1,946,684	45,912	1,900,772	59,114	1,841,658	(84,200)	1,925,858
688 Other general operations	1,218,463	22,420	1,196,043	80,190	1,115,853	(49,784)	1,165,637
Total general	**3,165,469**	**68,340**	**3,097,129**	**139,311**	**2,957,818**	**(134,004)**	**3,091,822**
700 Sales supervision	3,943	90	3,853	88	3,765	1,910	1,855
Total sales	**3,943**	**90**	**3,853**	**88**	**3,765**	**1,910**	**1,855**
711 Customer contracts	402,396	9,201	393,195	9,267	383,928	(11,810)	395,738
712 Meter reading	314,132	7,183	306,949	32,242	274,707	57,606	217,101
713 Customer billing	281,399	6,434	274,965	3,832	271,133	15,202	255,931
714 Credit and collections	41,465	948	40,517	(671)	41,188	19,365	21,823
Total customer accounting	**1,039,392**	**23,766**	**1,015,626**	**44,670**	**970,956**	**80,363**	**890,593**
Total operating	**6,402,511**	**142,241**	**6,260,270**	**375,748**	**5,884,522**	**(240,050)**	**6,124,572**

PNG notes that this table summarizes all operating labour, of which Account 685 is a single line item, as highlighted.

9.7 Please provide a similar table for Test Years 2018 and 2019, Decision 2016 and 2017 and Actual 2016 and 2017. Please identify the accounts impacted by increases due primarily to inflationary increases.

10.0 **Reference: Operating Expenses**
Exhibit B-1-1, Sections 2.3.7 and 3.2.2.1, pp. 36 and 127
Accounts 711, 713 and 714 – Customer Care

On page 127, PNG states:

> The actual costs for 2017 included in this account are $59,000 or 7.9% less than those approved under Decision 2017. The variance can primarily be attributed to lower than forecast contract costs for the customer billing system.

On page 36, PNG states:

> Forecast costs for Test Year 2018 of $785,000 and for Test Year 2019 of $805,000 are considered reasonable and consistent with the $754,000 for Decision 2017, with the increases primarily reflecting inflationary impacts.

10.1 Please provide the Actual 2017 and Forecast 2018 contract costs for the customer billing system, and provide an explanation for any variance greater than $50,000 or 10 percent.

11.0 **Reference:** **Operating Expenses**
Exhibit B-1-1, Section 2.3.8 pp. 36-37
Account 673, 675, 684, 712 and 718 – Other

On page 37 PNG states:

> Test Year 2018 expenses of $1.739 million are forecast to be $125,000 lower than Decision 2017 costs of $1.863 million. The primary factor for this variance is the elimination of four summer student positions effective Test Year 2018.

11.1 Please confirm, or explain otherwise, that none of the four summer student positions are expected to be replaced with new positions. If confirmed, please also explain why the positions will not need to be replaced.

12.0 **Reference:** **Maintenance Expenses**
Exhibit B-1-1, Section 2.4.1 p. 39
Account 866 — Compressors

PNG States on page 39 of the Amended Application:

> The expenses for Test Year 2018 are forecast to be $13,000 greater than Decision 2017 primarily due to an increase in contractor costs for compressor station maintenance. Test Year 2019 costs are similar to those for Test Year 2018 and primarily reflect inflationary increases.

12.1 Please explain if PNG considered tendering the work, and if not why not.

12.2 Please provide a detailed breakdown of the compressor costs between the Actual 2017 and Test Year 2018.

13.0 **Reference:** **Maintenance Expenses**
Exhibit B-1-1, Section 2.4.5, pp. 39-40
Account 865/885 - Other

13.1 Please explain the reasons for the increase in Account 865/885 costs between Actual 2017 and Test Year 2018.

C. ADMINISTRATIVE AND GENERAL EXPENSES

14.0 **Reference:** **Administrative and General Expenses**
Exhibit B-1-1, Sections 2.5 pp. 41-54; PNG-West 2016-2017 RRA proceeding,
Exhibit B-4, BCUC IR No. 15.1
Employees by department/function

In response to BCUC IR 1.15.1 in the PNG-West 2016-2017 RRA proceeding, PNG provided the following table:

				Number of Account 721 "Admin" Positions			
Departments/Functions	Test Year 2017	Test Year 2016	2015	2014	2013	2012	2011
Human Resources	3	3	3	2	2	2	2
Corporate - President	2	2	2	2	2	2	2
Vice President Operations & Engineering	1	1	0	0	0	0	1
Finance & Business Development (incl. acct & treasury)	9	9	9	9	9	8	6
Regulatory Affairs & Gas Supply & CIS	4	4	4	3	3	3	2
Treasury & Corporate Development (now Finance)	0	0	0	0	0	0	2
IT Services	3	3	3	3	3	3	3
Total (Non-Bargaining)	22	22	21	19	19	18	18

		Number of Operating & Maintenance Positions (incl 713 head office positions)					
Departments/Functions	2017	2016	2015	2014	2013	2012	2011
Operations - Non bargaining	12	12	12	11	11	11	11
Operating & Maintenance - Bargaining Unit	54	54	53	53	53	53	52
Total	66	66	65	64	64	64	63

14.1 Please provide a similar table for Test Years 2018 and 2019 and actuals for 2016 and 2017 for all of PNG. Please also identify any vacant positions.

15.0 **Reference:** **Administrative and General Expenses**
Exhibit B-1-1, Sections 2.5.1 and 3.2.2.3 pp. 41-42 and pp. 128-130; Appendix C, pp. 34, 36-40; PNG-West 2016-2017 RRA proceeding, Exhibit B-4, BCUC IR 16.1
Account 721 – Administration

On page 129 PNG states:

> The actual costs for 2017 included in this account are $337,000 or 9.2% greater than those approved under Decision 2017. This is primarily due to the actual figures reflecting all actual costs incurred, including those disallowed under Decision 2017, including the full Inter-affiliate charge by AltaGas ($1.414 million disallowed under Decision 2017) and the MTIP expense ($142,000 disallowed under Decision 2017). The variances due to disallowances were offset by favourable variances in actual costs from those forecast most notably for salaries and wages and STIP expenditures due to position vacancies, the actual AltaGas Inter-affiliate charge being less than anticipated and lower than forecast contractor charges primarily in the information technology area.

15.1 Please provide a comparison of the administration costs with the disallowed portion of the Inter-affiliate charge and Mid Term Incentive Plan (MTIP) expense removed for the 2016 and 2017 actuals. Please provide explanations for any significant variances.

15.2 Please provide a breakdown of the variances resulting from the vacant positions and the lower than forecast contractor charges noted in the preamble above.

15.3 Please discuss when the positions noted in the preamble above have been filled or are expected to be filled. If not expected to be filled, please explain.

15.4 Please discuss if the contractor charges noted in the preamble above are expected to remain similar to the 2017 actuals. Please explain why or why not.

Page 34 of Appendix C states:

> The following corporate Cost Pools and related general ledger accounts capture shared corporate services costs incurred by AltaGas for the benefit of PNG and other subsidiaries and business units:
>
> 1) Board of Directors
>
> 2) Executive Management
>
> 3) Accounting and Tax
>
> 4) Finance
>
> 5) Legal and Compliance
>
> 6) Information Technology / ERP System / Procurement
>
> 7) Office Services and Corporate Resources
>
> 8) Depreciation – Corporate Facilities.

On page 43 PNG provides the following table:

Table 19: Account 721 – Contractor Charges

BCUC Account 721	Test Year	2019 to 2018 Change		Test Year	2018 to 2017 Decision Change		Decision
Contractors/Personnel Agencies	2019	$	%	2018	$	%	2017
Corporate contractors	50,000	50,000	n/a	-	-	n/a	-
IT-related contractors	183,000	(24,000)	(11.6)%	207,000	17,000	8.9%	190,000
Finance contractors	62,000	1,000	1.6%	61,000	(121,000)	(66.5)%	182,000
HR - personnel agencies	81,000	2,000	2.5%	79,000	4,000	5.3%	75,000
Regulatory contractors	26,000	-	0.0%	26,000	16,000	160.0%	10,000
	402,000	29,000	7.8%	373,000	(84,000)	(18.4)%	457,000

15.5 Please expand the above table to include actuals for 2016 and 2017. Please also clearly identify any one-time contractors which do not carry forward into future years.

15.6 Please explain how each of the services provided by the contractors in the above table differ from the services provided by AltaGas as detailed on pages 36-40 of the KPMG report in Appendix C of the Amended Application.

In response to BCUC IR 1.16.1, in the PNG-West 2016-2017 RRA proceeding, PNG provided the following table:

Account 721 - Administration ($'s)	Test Year 2014 (Update)	Test Year 2014 (Original)	Variance 2014 (Update - Original)	Actual 2013	Decision 2013
Accomodations	34,678	34,678	-	17,264	26,582
Contractors & consulting fees	244,610	244,610	-	312,645	256,341
Courses & seminars	33,944	33,944	-	20,663	34,782
Data Lines	42,917	42,917	-	24,605	40,429
Dues & Subscriptions	31,457	31,457	-	29,237	27,123
IT Supplies	26,065	26,065	-	64,194	24,450
Labour (incl bonus)	2,949,889	2,885,786	64,103	2,806,078	2,853,803
Meals & Ent	19,730	19,730	-	13,812	17,300
Miscellaneous (courier, etc.)	17,545	17,545	-	13,879	15,112
Office Supplies & Postage	24,491	24,491	-	23,717	26,297
Phone	31,273	31,273	-	29,119	30,226
Leased Vehicles and Photocopiers	29,409	29,409	-	27,699	29,886
Office Rent & parking	261,693	261,693	-	259,650	263,606
Other (<$10,000)	19,874	19,874	-	25,942	17,051
Transportation	76,553	76,553	-	56,999	68,771
	3,844,128	3,780,025	64,103	3,725,503	3,731,759
Less: Disallowed Costs					
Head Office Salaries	-	-	-	-	(180,000)
MTIP Benefit Expense	-	-	-	-	(98,000)
	-	-	-	-	(278,000)
Subtotal	3,844,128	3,780,025	64,103	3,725,503	3,453,759
Shared Service Cost Recovery from PNG(NE)	(1,377,000)	(1,374,000)	(3,000)	(1,263,000)	(1,263,000)
Account 721 Subtotal	**2,467,128**	**2,406,025**	**61,103**	**2,462,503**	**2,190,759**
AltaGas Service Charges	1,586,000	1,771,000	(185,000)	1,621,000	1,632,000
Less: Disallowed	(675,000)	(865,000)	190,000	-	(1,011,000)
	911,000	906,000	5,000	1,621,000	621,000
Shared Service Cost Recovery from PNG(NE)	(312,000)	(308,000)	(4,000)	(209,000)	(209,000)
AltaGas Service Charges Subtotal	**599,000**	**598,000**	**1,000**	**1,412,000**	**412,000**
Total	**3,066,128**	**3,004,025**	**62,103**	**3,874,503**	**2,602,759**

15.7 Please provide a similar table for: Test Years 2018 and 2019, Decision 2016 and 2017 and Actual 2016 and 2017.

15.8 Please provide explanations for any variances greater than $50,000 or 10 percent compared to the previous year actual or the Decision.

16.0 **Reference: Administrative and General Expenses**
Exhibit B-1-1, Section 2.5.2 pp. 44-45; Appendix C, pp. 34, 36-40
Account 722 – Special Services

On page 45 PNG states:

> Human resource legal and consulting fees are forecast to increase by $39,000 in Test Year 2018 over Decision 2017 due to the increased involvement of legal and consulting services required to assist with bargaining-unit matters and specialized human resource initiatives. The increase for Test Year 2019 is due to inflation.

CEO - general consulting fees are forecast to increase by $48,000 in Test Year 2018 over Decision 2017 due to third-party expertise anticipated for development of programs focused on improving the company's safety approach and to foster a safety culture within the organization. The increase for Test Year 2019 is due to inflation.

Engineering and operations consulting fees for Test Year 2018 are forecast to be higher than Decision 2017 by $100,000 due to a provision for costs of external expertise to assist with the planned implementation of a new geographical information system. This is a multi-year project and PNG-West has included an inflationary increase for Test Year 2019.

16.1 Please provide the anticipated start and end date of the "specialized human resource initiatives," the development of programs focused on safety and the new geographical information system project noted in the preambles above, as well as a breakdown of the total cost of each of the initiatives/projects by test year.

16.2 Please discuss why the initiatives and projects mentioned in the preambles above are necessary.

16.3 Please explain why each of the initiatives and projects mentioned in the preambles are anticipated to continue into test year 2019.

16.4 Please confirm, or explain otherwise, that the new geographical information system mentioned in the above preamble is for the exclusive use of PNG West and PNG(NE).

16.4.1 Please discuss how the services related to the implementation of the new geographical information system differs from the IT services provided by AltaGas Limited (AltaGas) as detailed on page 39 of the KPMG report in Appendix C of the Amended Application.

On page 35 PNG states:

Test Year 2018 expenditures of $2.801 million are forecast to increase by approximately $383,000 or 15.8% over Decision 2017. Factors contributing to this increase include: additional engineering projects including digital data mapping and the implementation of a geographical information system; increased labour costs attributable to new positions in the areas of engineering and records management; asset management system licensing costs, and inflation.

On pages 89-90 PNG states:

In the third quarter of 2017, PNG engaged an engineering/geomatics consultancy firm to execute a needs assessment and requirements project to support the GIS initiative….

Based on a comprehensive assessment of alternatives, PNG has plans to execute implementation recommendations over a three-year period (2018 to 2020). The overall project cost is estimated at $2.4 million, which will be incurred over three years and will be shared by PNG-West and PNG(NE) service areas.

16.5 Please confirm, or explain otherwise, that the consulting fees for the new geographical information system mentioned on page 45 of the Amended Application are for the same geographic information system (GIS) initiative as those mentioned in the above preamble.

16.5.1 If confirmed, please also confirm, or explain otherwise, that the estimated project cost of $2.4 million includes the costs of the consulting fees and general operating costs related to the new geographical information system recorded in Accounts 722 and 685, respectively.

Table 22 on page 45 of the Amended Application provides a breakdown of the consulting fees in Account 722 for Test Years 2018 and 2019 and for Decision 2017.

16.6 Please expand Table 22 to include actuals for 2016 and 2017.

16.7 Please explain how each of the services provided by the consultants recorded in Account 722 in Table 22 of the Amended Application differ from the services provided by AltaGas as detailed on pages 36-40 of the KPMG report in Appendix C of the Amended Application.

17.0 **Reference: Administrative and General Expenses**
Exhibit B-1-1, Sections 2.5.4 and 3.2.2.3 pp. 46-49 and pp. 129-130;
PNG-West 2016-2017 RRA, Exhibit B-4, BCUC IRs 1.24.1-1.24.3
Account 725 – Employee Benefits

On page 47 PNG states:

> PNG-West further notes that a new health spending account benefit for bargaining unit employees has been established as part of the 2017 negotiations in finalizing the collective agreement applicable to the period November 1, 2016 to October 31, 2019. Other than this change, there have been no significant changes to the PNG-West employee benefit plan since the last revenue requirements application approved under Decision 2017.
>
> PNG-West also notes that it has not incorporated the impact of key tax changes recently announced by the BC Provincial government in the 2018 Budget, specifically with regard to the new Employer Health Tax and elimination of Medical Service Program premiums.

17.1 Please discuss if PNG-West expects the new health spending account to continue after October 31, 2019.

17.2 Please provide an estimate of the impact of the new Employer Health Tax and elimination of the Medical Services Plan premiums for Test Years 2018 and 2019.

In response to BCUC IR 1.24.1 in the PNG-West 2016-2017 RRA proceeding, PNG provided the following table:

($'s)	With Bonus	Without Bonus	Difference	@ 2/3	Per Rate Application
Test Year 2016					
Pension Expense					
Executive	451,000	314,000	137,000	91,333	359,667
Non-bargaining Unit	617,000	571,000	46,000		617,000
Bargaining Unit	720,000	720,000	-		720,000
	1,788,000	1,605,000		91,333	1,696,667
Test Year 2017					
Pension Expense					
Executive	436,370	303,814	132,556	88,371	348,000
Non-bargaining Unit	596,985	552,478	44,508		596,985
Bargaining Unit	696,644	696,644	-		696,644
	1,730,000	1,552,936		88,371	1,641,629

17.3 Please provide a table similar to the one above that details the calculation for both Test Years 2018 and 2019 forecast amounts, and the 2016 and 2017 actual amounts. Please provide explanations for variances greater than $50,000.

In response to BCUC IR 1.24.2 in the PNG-West 2016-2017 RRA proceeding, PNG provided the following table:

($'s)	Test Year 2017	Test Year 2016	Actual 2015	Decision 2015	Actual 2014	NSP 2014	Actual 2013	Decision 2013	Actual 2012	Decision 2012	Actual 2011	NSP 2011
Company Pension Plan												
DB Pension Expense	1,641,000	1,697,000	1,977,000	1,776,000	1,688,000	1,688,000	1,991,000	1,991,000	1,484,003	1,484,000	1,102,000	1,063,000
Supplemental Retirement Plan LofC and Trustee Fees	61,120	59,629	72,192	53,915	40,349	50,147	54,980	69,288	53,991	59,914	53,858	78,600
ACP/RRSP Expenses	55,053	53,710	47,523	51,250	47,636	50,147	48,503	44,006	51,321	44,000	46,295	37,175
DC Pension Expense	11,557	11,275	24,114	28,700	25,809	25,104	23,593	25,585	23,130	31,205	22,020	35,000
	1,768,730	1,821,614	2,120,829	1,909,865	1,801,794	1,813,398	2,118,076	2,129,879	1,612,445	1,619,119	1,224,173	1,213,775
Other Programs												
Non-Pension Post Ret. Benefits (non-tax deuct.)	403,000	403,000	440,000	440,000	379,000	379,000	679,000	679,000	479,003	479,000	584,090	584,000
Non-Pension Post Ret. Plan RCA Trustee Fees	1,777	1,738	3,757	1,738	1,784	2,045			-	2,424	-	2,400
Other												
Coffee and water service	28,926	28,359	24,666	27,777	26,846	27,979	24,160	26,531	24,272	24,598	24,906	25,402
Educational	11,132	10,914	7,600	10,914	6,500	10,914	7,400	8,571	9,050	13,834	9,200	13,834
Other	64,404	62,986	62,965	58,978	52,827	38,725	36,440	24,109	18,232	19,119	69,268	14,600
	509,239	506,997	538,988	539,407	466,957	458,663	747,000	738,211	530,557	538,975	687,464	640,236

17.4 Please provide a table similar to the one above for Actual 2016 and 2017, Decision 2017 and Test Years 2018 and 2019.

In response to BCUC IR 1.24.3 in the PNG-West 2016-2017 RRA proceeding, PNG confirmed that the decrease in pension expense in 2016 and 2017 over Decision 2015 is the result of a <u>higher</u> discount rate. [Emphasis added]

On page 48 PNG states:

> The decrease in DB and NPPRB costs for Test Year 2018 and Test Year 2019 over Decision 2017 are primarily a result of discount rates <u>going down</u> (3.81% to 3.60%) and as a result of actuarial gains in the plans recognized at the end of 2017. [Emphasis added]

17.5 Please reconcile the two statements above.

On page 49 PNG provides the following table:

Table 25: Employee Benefit Load Rates

Employee Affiliation	Test Year 2019	2019/2018 Difference %	Test Year 2018	2018/Decision 2017 Difference %	Decision 2017	Decision 2016	Decision 2015	NSP 2014	Decision 2013
Executive	34.0%	0.1%	33.9%	(9.5)%	43.4%	41.4%	45.3%	38.4%	56.3%
Non-bargaining Unit	32.0%	(1.1)%	33.1%	(4.6)%	37.7%	36.9%	39.0%	37.6%	32.7%
Bargaining Unit - PNG-West	36.1%	(1.5)%	37.6%	(9.5)%	47.1%	47.9%	51.5%	52.4%	66.5%
Bargaining Unit - PNG(N.E.)	37.5%	(1.3)%	38.7%	(10.8)%	49.5%	48.0%	49.6%	47.2%	58.2%

17.6 Please provide the actual load rates for 2016 and 2017 and provide explanations for any significant variances from the rates approved in the Decisions.

17.7 Please explain how employee benefit load rates are calculated and provide an illustrative example of the calculation for Test Year 2018 for "Executive".

On page 130 PNG states:

> The actual costs for 2017 included in this account are $60,000 or 1.7% lower than those approved under Decision 2017. This is mainly due to lower CPP, EI and savings plan costs attributable to vacant positions.

17.8 How many actual vacant positions were there in 2017 as opposed to forecast and when were these positions filled or are expected to be filled?

17.8.1 Please discuss if the vacancies in the above preamble are due to the positions being new or are replacements for employees that have retired or have otherwise been terminated.

18.0 **Reference: Administrative and General Expenses**
Exhibit B-1-1, Sections 2.5 and 2.5.5 pp. 49-50 and p. 41
Account 728 – General

18.1 Please provide the Actual 2016 and 2017 with the disallowed costs removed for General (Account 728).

D. INTER-AFFILIATE CHARGE

19.0 **Reference: Inter-affiliate Charge**
Exhibit B-1-1, Sections 2.5.1 and 2.5.7.1, pp. 43-44 and pp. 51-52, Appendix C
AltaGas inter-affiliate charges

19.1 Please provide the incremental revenue deficiency and rate impact for Test Years 2018 and 2019 based on a scenario where PNG was approved to recover the full AltaGas inter-affiliate charges in each of the Test Years. Please show all supporting calculations.

On page 52 PNG states:

> Ultimately, PNG expects to seek recovery of all costs allocated by its parent company associated with maintaining its capital structure, providing access to capital and delivering the various other corporate services as the economic circumstances of PNG's business improves.

In response to BCUC IR 1.20.3 in the PNG-West 2016-2017 RRA proceeding, PNG stated:

> Given the termination of the DC LNG project, PNG is hopeful that it will be successful in finding a new customer to fill excess capacity in its western system within the next 3-5 years and, as noted in previous rate applications, PNG will seek full recovery of the AltaGas Inter-Affiliate charges at that time.

19.2 Does PNG have an update on the estimated timeframe for when it would likely seek full recovery of the AltaGas inter-affiliate charge?

On page 46 of Appendix C, PNG provides the following table:

Table 1 - PNG to Self-Provide AltaGas's 2018/2019 Corporate Service Activities

Shared services Function	BOD /FTE Required	Salaries & Benefits	THIRD PARTY & OTHER EXPENSE	TOTAL 2018	TOTAL 2019(3)
Board of directors	7	$ -	$828,500	$828,500	
Accounting and Tax	1	167,800	262,900	430,700	
Finance/Treasury	1	278,400	-	278,400	
Legal & Compliance	-	-	232,100	232,100	
Information Technology/ ERP/ Procurement	-	-	34,000	34,000	
Subtotal		$446,200	$1,357,500	$1,803,700	
Incremental Benefits from AltaGas (2)			469,000	469,000	
		$446,200	$1,826,500	$2,272,700	$2,318,200
Inter-Affiliate Charges from AltaGas				$1,640,000	$1,159,000

On page 49 of Appendix C, it states:

> In its 2013 Revenue Requirement Application, PNG noted its 2009-2011 three-year average historical costs to operate as a stand-alone public company, excluding Deferred Stock Unit ("DSU") adjustment costs, was about $0.8 million. The difference between PNG's current estimate of $1.8 million (Table 1) and the $0.8 million historical cost are mainly attributable to increases in board of director costs, the addition of two FTEs to perform the essential corporate functions and general inflation. These cost increases are driven by the fact that PNG is becoming more capital intensive and would require greater expertise for its financing needs, as well as greater governance, disclosure and reporting requirements associated with publicly listed companies.

19.3 Please recreate the above table with an additional column representing the 2009-2011 three-year average historical costs to operate as a stand-alone public company, excluding Deferred Stock Unit (DSU) adjustment costs.

19.4 Please confirm, or explain otherwise, that the additional two FTEs mentioned in the above preamble are for the Accounting and Tax and Finance/Treasury functions noted in the table above.

19.4.1 Please confirm, or explain otherwise, that these are positions that PNG did not have prior to its acquisition by AltaGas. If confirmed, please discuss if these functions were previously outsourced.

On page 38 of Appendix C, it states:

> Costs are higher in 2018/2019 due to increased headcount in Communication, and higher treasury expenses due to higher employee costs and inclusion of corporate insurance premium in Treasury.

19.5 Please clarify in which cost pool the corporate insurance premium mentioned in the above preamble was previously included, and why it was included in Treasury for Test Years 2018 and 2019 but not previously.

On page 44 of the Amended Application, PNG provides the following table:

Table 20: AltaGas Inter-affiliate Charge - Consolidated

Expense Item	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
AltaGas Management Fee - per AltaGas	1,159	(481)	(29.3)%	1,640	(489)	(23.0)%	2,129	1,913	2,057	2,106	1,550	1,632
Disallowed by Commission Decision	(416)	494	(54.3)%	(910)	504	(35.6)%	(1,414)	(1,198)	(1,342)	(1,391)	(871)	(1,011)
AltaGas Fee Recovery - Consolidated	743	13	1.8%	730	15	2.1%	715	715	715	715	679	621
Applied for Fee Recovery - per PNG	743	13	1.8%	730	15	2.1%	715	715	715	715	910	750

The following is extracted from Tab 1, page 6 of the Amended Application:

(000s)

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	721 Administration	$3,184	$3,083	$3,356	$2,351	$2,866	$2,402	$2,492	$2,450
2	AltaGas inter-affiliate charge	882	1,371	1,865	1,650	1,798	1,854	1,305	1,412
3	Total administration	4,066	4,454	5,221	4,001	4,664	4,257	3,797	3,861
29	Cost adjustments								
30	721 - Head office salaries	0	0	0					
31	728 - 50% of donations & corporate sponsorships	(40)	(39)	(40)					
32	725 - 1% portion of employee savings plan	(23)	(22)	(27)					
33	728 - Stock option	(22)	(22)	(68)					
34	721 - MTIP benefit expense	(105)	(105)	(142)					
35	725 - Pension expense on bonuses and incentives	(17)	(16)	(89)					
36	75x - Non-regulated business & benefit allocations	0	0	0					
37	721 - AltaGas inter-affiliate charge	(416)	(910)	(1,414)					
38	Subtotal cost adjustments	(622)	(1,114)	(1,781)	0	0	0	0	0

19.6 Please discuss how much of the decrease in the AltaGas management fee is due to a reduction in the cost pools versus a reduction in the cost pool allocators.

19.7 Please reconcile the amounts on lines 2 and 37 of the above extract with amounts in Table 20 on page 44 of the Amended Application.

E. TRANSFERS TO CAPITAL

20.0 **Reference: Transfers to Capital**
Exhibit B-1-1, Sections 2.6, 3.2.1.1 and 3.2.1.4, pp. 55-56 and 123;
PNG-West 2016-2017 RRA, Reasons for Decision
Transfers to Capital (Capitalized Overhead)

20.1 Please provide the estimated time in support of forecast capital activities for corporate/management and support staff for Test Years 2018 and 2019, and the actual time spent for 2016 and 2017.

20.1.1 Please provide an explanation for variances greater than 10 percent in actual and estimated time in support of forecast capital activities.

20.2 For Test Years 2018 and 2019, 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 salaries and benefits to capital projects.

20.3 Please explain why the actual Operating Expense transfers to capital for 2016 were $78,000 (or 21.5 percent) more than forecast for Decision 2016.

On page 12 of the Reasons for Decision for the PNG-West 2016-2017 RRA proceeding, it stated:

> [T]he Panel expects PNG to capitalize the new VP of Engineering's salary in accordance with its approved capitalization policies and requests that PNG report on the actual capitalization rate as compared to the forecast capitalization rate for the VP of Engineering's salary as part of PNG's next RRA filing.

20.4 Please provide the actual capitalization rate as compared to the forecast capitalization rate for the VP of Engineering's salary for 2016 and 2017.

F. DEPRECIATION

21.0 **Reference: DEPRECIATION**
Exhibit B-1-1, p. 59 and Appendix D, p. II-29
Positive Salvage

On page 59 of its Amended Application, PNG states that:

> For Account 485 – Heavy Work Equipment, PNG made the decision to not to incorporate the positive salvage recommendation based on the company's experience of owning and operating the equipment in this account for the entirety of their useful lives and of not realizing any proceeds on disposition.

With respect to Account 485, the Depreciation Study states on page II-29 that:

> The previous depreciation study included a net salvage of 15 percent. The first year of recorded net salvage activity for this account is 2012. For the period 2012 to 2016, the net salvage has ranged from 7 percent to 24 percent with a cumulative value of 10 percent. Interviews with the PNG's Operations and Management have indicated that the historically indicated value of 10 percent is a reasonable expectation for the equipment in this account. Based on historical indications and the comments from the Operations and Management personnel, Concentric views that 10 percent is a reasonable net salvage expectation for the equipment in this account.

21.1 Does the following statement on page II-29 of the Depreciation Study refer to the actual net positive salvage recorded for Account 485 between 2012 and 2016? If not, please clarify what this statement refers to.

"For the period 2012 to 2016, the net salvage has ranged from 7 percent to 24 percent with a cumulative value of 10 percent."

21.1.1 Please elaborate on why PNG has not incorporated the positive salvage recommendation for Account 485, despite the information provided on page II-29 of the Depreciation Study.

22.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 58-61 and Appendix D
Net salvage - rate impact

On page 58 of its Amended Application, PNG states that the result of the Depreciation Study is:

> … a reduction in depreciation expense compared to that which would have been calculated under the rate previously in place based on the parameters of a prior study, with Test Year 2018 depreciation expense decreasing to $4.440 million from $5.135 million for Decision 2017. Test Year 2019 depreciation expense is forecast to be $4.425 million.

On page 59 of its Amended Application, PNG states that:

> If PNG-West were to record a provision for negative salvage in its depreciation for the applicable accounts, depreciation expense for Test Year 2018 and Test Year 2019, would be greater by $1.908 million and $1.962 million, respectively.

Further, on page 61 of its Amended Application PNG states that:

> PNG's basis for not incorporating negative salvage is the materiality of the negative salvage estimates and the significant adverse rate impacts that will result from incorporating these estimates into depreciation expense at this time.

22.1 Please provide the Test Years 2018 and 2019 rate impact of incorporating the negative salvage values recommended in the Depreciation Study, which results in depreciation expense for Test Years 2018 and 2019 being greater by $1.908 million and $1.962 million, respectively.

22.2 Please provide the net impact of incorporating all of the recommendations made by Concentric in the Depreciation Study, including the change in both depreciation rates and *net* salvage values. Please provide the impact on both depreciation expense and rates for each of Test Years 2018 and 2019.

22.3 Please confirm that if PNG adopted Concentric's recommendation regarding negative salvage values, it would have a one-time rate impact for customers during the year of transition (i.e. Test Year 2018). If not confirmed, please explain and provide a numerical example for illustration.

22.3.1 In the event that Concentric's recommendation regarding negative salvage values were adopted by PNG, please discuss if PNG would consider a transition period to smooth out the immediate impact on customer rates.

22.3.2 In the event that Concentric's recommendation regarding negative salvage values were adopted by PNG, please discuss if PNG would consider offsetting the immediate impact on customer rates with amortization of the Option Fee Payment deferral account.

22.4 If Concentric's recommendations regarding negative salvage accounting were adopted, how would the annual negative salvage accrual collected from customers get recorded for regulatory accounting purposes? For example, would the amount collected be recorded as a rate base credit account? Please explain and provide an illustrative example.

22.5 Please explain if PNG agrees with the following statements on pages I-4 and I-5 of the Depreciation Study as it relates specifically to PNG. Please discuss why or why not.

> The longer the delay in recognizing net negative salvage, the higher future depreciation rate will be as PNG's depreciation rates are based on its net book value amortized over a remaining life basis. Each year of delay will increase the differential between booked net book value and calculated net book value. As

such, the resultant depreciation rates will increase proportionately.
…
Although a comparison of the current revenue requirements related to a net salvage accrual and the current revenue requirements related to expensing of net salvage may indicate that the accrual is higher at a single point in time, over time the revenue requirements and the present value of those revenue requirements will be less if the net salvage cost is accrued over the life of the asset. The reason for the lower revenue requirements with the accrual of net salvage is the impact of the accruals on rate base. That is, as net salvage accruals are recorded to the depreciation reserve, the accumulated depreciation balance in the reserve increases and reduces subsequent determinations of rate base in future periods.

23.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 58-61 and Appendix D
Plant Gains and Losses deferral account

23.1 Please provide the actual additions and amortization expense for the Plant Gains and Losses deferral account for each year between 2012 and 2017, and forecast 2018 and 2019, broken down into the following categories:

- Ordinary;
- Salvage Value;
- Retirement Costs.

23.1.1 Please explain if any of the above three categories for the Plant Gains and Losses deferral account would no longer be required in the event that all of the net salvage values recommended in the Depreciation Study were adopted by PNG.

24.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 58-61 and Appendix D
Negative Salvage

On page 53 of the Commission's decision in the PNG 2013 RRA proceeding, the Commission states:

> …the Panel is supportive of PNG's decision to include an evaluation of the potential of using negative salvage accounting in its next Depreciation Study. Our expectation is that this evaluation will include a **thorough examination of the pros and cons of utilizing negative salvage accounting and the costs of its implementation.** [Emphasis added][1]

In the FortisBC Energy Utilities (FEU) 2012-2013 Revenue Requirements and Natural Gas Rates Application, FEU's Application (Exhibit B-1) includes an Asset Retirements Obligation Report filed as Appendix E-2.[2] The Report outlines 4 options for negative salvage accounting on pages 9-12, as follows:

- Pay as You Go;
- Traditional Approach;
- Asset Retirement Obligation (ARO)Approach;
- Hybrid Approach.

[1] Pacific Northern Gas Ltd. (PNG) 2013 Revenue Requirements Application (RRA) Decision, p. 53.
[22] FortiBC Energy Utilities (FEU) 2012-2013 Revenue Requirements and Natural Gas Rates Application, Exhibit B-1, Appendix E-2, pp. 9-12.

24.1 Please provide a thorough analysis from PNG's perspective of the pros and cons of incorporating negative salvage values into depreciation rates, as recommended by Concentric in the Depreciation Study, versus maintaining PNG's current methodology for accounting for negative salvage.

24.2 Please provide an analysis of the full costs of implementing the recommendation by Concentric to incorporate negative salvage values into depreciation rates.

24.3 Please discuss if PNG considered any options for negative salvage accounting other than the methodology currently used by PNG and the methodology recommended by Concentric. For example the ARO Approach and/or Hybrid Approach referenced in the preamble.

25.0 **Reference: DEPRECIATION**
Exhibit B-1-1, p. 60 and Appendix D, pp. I-8 - I-10, II-4
Negative Salvage

On page 60 of its Amended Application, PNG states that: "PNG-West, like many utilities, prefers to record actual costs of removal at the time incurred. This treatment is consistent with the practice of other utilities and is an allowable method under the Commission's Uniform System of Accounts."

On pages I-8 – I-10 of the Depreciation Study, it is noted that the issue of net salvage recovery has been reviewed recently in several jurisdictions, with several examples provided from 2011 and 2012.

Page II-4 of the Depreciation Study describes the procedures for estimating net salvage as consisting "to a large extent on the approved net salvage parameters for PNG peers, interviews with PNG's Management and Operational groups, and on the experience and judgement of Concentric."

25.1 Please confirm, or explain otherwise, that PNG's current methodology of recording actual costs or removal at the time incurred is an allowed practice under US Generally Accepted Accounting Principles (GAAP). Please provide the applicable US GAAP section(s) in support of this response.

25.2 Please provide examples of other Canadian gas distribution utilities that use the same methodology as PNG for net salvage accounting.

25.2.1 Please provide examples of other Canadian gas distribution utilities that use the same methodology as recommend by Concentric for net salvage accounting.

25.3 With respect to the examples from other jurisdictions provided on pages I-9 to I-10 of the Depreciation Study, are there any more recent examples? If so, please provide the details.

25.4 Please provide a list of the peer companies used by Concentric in arriving at its net salvage recommendations.

26.0 **Reference:** **DEPRECIATION**
Exhibit B-1-1, Appendix D, pp. II-9, II-20
Negative Salvage – Specific Accounts

On page II-9 of the Depreciation Study, Concentric recommends a net salvage of negative 25 percent for Account 418.00 – Gathering – Purification Equipment based on the following rationale:

> A peer comparison of a similar Canadian gas utility similarly has Pre-Treatment Equipment net salvage value of negative 10 percent as its net salvage parameter. Interviews with PNG's Operations and Management staff have indicated that negative 25 percent is a reasonable expectation for the equipment in this account. Concentric viewed that the comments from the Operational and Management personnel combined with the peer analysis, and on the professional judgement of Concentric was the most reasonable expectation for the equipment in this account. As such, a net salvage of negative 25 percent is recommended to represent the expectations for the equipment in this account.

On page II-20 of the Depreciation Study, Concentric recommends a net salvage value of negative 60 percent for Account 473.00 – Distribution – Services.

26.1 Please elaborate on the reasons why Concentric has recommended a net salvage of negative 25 percent for Account 418, given that the peer analysis indicated a net salvage of negative 10 percent. Please include the specific data and information relied upon in making the recommendation.

26.2 Please expand on the reasons why a net salvage value of negative 60 percent is recommended by Concentric for Account 473. Please include the specific data and information relied upon in making the recommendation.

26.3 Please provide an illustrative example of how the annual accrual for net salvage is calculated, using Account 473 and the following inputs from page II-9 of the Depreciation Study:

- Book Value: $54.4 million;
- Net Salvage Value: -60 percent;
- Annual Net Salvage Accrual: $1,081,711.

27.0 **Reference:** **DEPRECIATION**
Exhibit B-1-1, p. 60, Appendix D, p. IV-2
Depreciation rates

On page 60 of its Amended Application, PNG states that:

> For most accounts, the annual and accrued depreciation has been calculated by the straight-line method using the average life group procedure for the assets in a particular class. For certain general plant accounts, the annual and accrued depreciation are based on amortization accounting.

Page IV-2 of the Depreciation Study states that: "The annual accrual rates and the accrued depreciation were calculated in accordance with the straight-line method, using the equal life group procedure based on estimates which reflect considerations of current historical evidence and expected future conditions."

27.1 Please clarify if the annual and accrued depreciation has been calculated using the average life group procedure or the equal life group procedure.

27.2 Please describe each of the following terms and how they are applicable to the Depreciation Study filed in the Amended Application:

- Average Life Group Procedure;
- Equal Life Group Procedure;
- Amortization Accounting.

28.0 **Reference: DEPRECIATION**
Exhibit B-1-1, Appendix D, p. II-23
Depreciation rates

For Account 477.00 – Distribution – Measuring and Regulating Equipment, Iowa 35-R4 is recommended in the Depreciation Study to represent the expectations for the equipment in this account.

28.1 Please explain if a retirement rate analysis was prepared for Account 477. If so, please provide the results and if not, please explain why not.

29.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 59-69 and Appendix D, p. II-5
Depreciation of Land Rights

On pages 50-60 of its Amended Application, PNG states that:

> Consistent with the 2010 Depreciation Study, the 2017 Depreciation Study recommends the depreciation of Land Rights (Accounts 461, 471 and 481) over a period of 75 years. At the time of implementing the recommendations of the 2010 Depreciation Study, PNG made the determination that its Land Rights had an indefinite life and as such should not be depreciated.

29.1 Please provide the factors that were considered by PNG in making the determination that Land Rights have an indefinite life and should not be depreciated.

29.2 Please explain if PNG's proposed treatment to not depreciate Land Rights is acceptable under US GAAP. Please provide the applicable US GAAP section(s) in support of this response.

29.3 Please provide examples of other Canadian gas distribution utilities that use the same methodology for Land Rights as proposed by PNG.

G. DEFERRAL ACCOUNTS AND AMORTIZATION

30.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 64; PNG 2016-2017 RRA Decision, pp. 17-18
EMAT 2018 Tool Run

On page 64 of the Amended Application, PNG requests approval of a new deferral account to record the cost of the EMAT ILI runs in a rate base deferral account to be amortized over 10 years, and that this treatment be accorded to future EMAT ILI costs on a go-forward basis.

In the PNG 2016-2017 RRA Decision, the Commission denied PNG's request to record the EMAT ILI tool costs in a new rate base regulatory account and directed PNG to capitalize the costs in accordance with US GAAP. Page 18 of the reasons for decision states:

> The Panel is not persuaded that the use of a regulatory account is more administratively efficient. Further, given PNG's statements that US GAAP allows for these costs to be capitalized, the Panel considers this the most appropriate treatment, as it provides the same relief against lumpy and volatile expenses as a regulatory account. In the Panel's

> view, it is more appropriate to use regulatory accounts in circumstances where financial accounting principles do not allow for capitalization of costs and where the recording of such costs as operational expenses would result in large and volatile rate impacts. While the Panel acknowledges PNG's statement that it does not currently have a plant account with an appropriate depreciation rate, the Panel does not find this to be a compelling reason to depart from US GAAP in favour of the proposed new regulatory account.

In its response to BCUC IR 1.41.2 in the PNG West 2016-2017 RRA proceeding, PNG states:

> This is the first time an EMAT tool is available to be used for the size of PNG's transmission line and this first use would establish baseline data which would be then used to enhance pipeline asset integrity. This integrity test is required to be repeated every 7 to 10 year cycle.
> …
>
> Following the principles established during the 2013 RRA proceeding, PNG believes that a rate base deferral account to be amortized over a period of 5 years would be appropriate.[3]

30.1 Please confirm, or explain otherwise, that both expensing and capitalizing the EMIT ILI tool runs is allowed under US GAAP. Please provide the applicable US GAAP section(s) in support of this response.

30.2 Please discuss if there are any circumstances under which PNG would be required to repeat the integrity test more or less frequently than every 7-10 years.

30.2.1 In the event that the integrity test is repeated less frequently than 10 years, would PNG propose adjusting the amortization period from 10 years to reflect the actual timeframe of repeating the test?

30.3 Please discuss the circumstances under which PNG would consider it appropriate to use regulatory accounts where financial accounting principles allow for capitalization of costs.

31.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 64; Exhibit B-4 in the PNG 2016-2017 RRA proceeding, BCUC IR 41.2
EMAT 2018 Tool Run

On page 64 of its Amended Application, PNG states that:

> EMAT ILI run costs are fully deductible for tax purposes in the year incurred, and therefore, recording these costs as an addition to plant capital results in timing differences impacting the current income taxes and thereby benefiting the current year customers. PNG-West notes that capitalizing the EMAT ILI run costs in a deferral account would more fairly allocate these costs between current and future ratepayers as they are effectively recorded and amortized on a net of tax basis.

31.1 Please provide the annual revenue requirement impact for each of 2018 – 2028 under each of the following two scenarios, broken down between income taxes, depreciation, amortization, return on equity and interest:

- Record the $1.2 million of EMAT ILI run costs in a deferral account in 2018 and amortize over 10 years;
- Record $1.2 million of EMAT ILI run costs as capital and depreciate over 10 years.

[3] PNG-West 2016-2017 RRA, Exhibit B-4, BCUC IR 41.2, p. 113.

31.1.1 Please discuss if there are any additional ratepayer benefits to recording the EMAT ILI run costs in a deferral account, rather than capitalizing them, other than the tax implications.

32.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 64
EMAT 2018 Tool Run

On page 64 of its Amended Application, PNG states the following:

- PNG-West complied with this decision and in 2016 recorded $487,000 of capital expenditures in plant to BCUC Account 469.
- [f]or the Test Year 2018, PNG-West is forecasting to spend $1.2 million on EMAT ILI runs.

On page 34 of its Application, PNG describes operating expenses in Account 656 – Pipelines associated with running the in-line inspection tool.

32.1 Please provide the basis for the $1.2 million Test Year 2018 forecast cost related to EMAT ILI runs.

32.1.1 Please explain why the costs associated with the EMAT ILI tool runs have increased from $487,000 in 2016 to forecast $1.2 million in Test Year 2018.

32.1.2 Please explain the difference between the $1.2 million in costs associated with the EMAT ILI runs and the $145,000 in operating costs for each of Test Year 2018 and 2019 associated with in-line inspection tool runs.

32.2 Please provide the actual 2016 and 2017 costs associated with the EMAT ILI tool runs and explain any variances from approved costs.

33.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 65
Overhauled Compressor Engine Spare

On page 65 of its Amended Application, PNG states that:

> PNG-West is therefore requesting Commission approval to create a new rate base deferral account to record the costs of the compressor engine overhauls to be amortized only when the asset is put into service and for a minimum period of 5 years. PNG-West believes that this proposal is also consistent with treatment afforded these types of costs under US GAAP.

33.1 Please elaborate on why the overhaul is required, given that there is only one out of six compressors being utilized at any point in time. Specifically, please address any issues with the existing equipment.

33.2 When does PNG expect that the overhauled engine will be placed in service?

33.3 Does PNG have an overhaul schedule for the six compressors that are currently being rotated? If so, please provide the details.

34.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 65
Overhauled Compressor Engine Spare

On page 65 of its Amended Application, PNG describes the proposed accounting treatment for the costs associated with the overhaul of the compressor engine spare as follows:

> … in order to ensure the fair allocation of the costs to overhaul the engine between current and future ratepayers, a rate base deferral account should be created. This proposed treatment would address the same concerns brought forth with the EMAT ILI run costs since these overhaul costs would also be expensed for tax purposes in the year incurred. The proposed deferral account would then be amortized over a minimum period of 5 years commencing when the compressor engine is put into service as the life cycle expectancy of the overhaul is 5 years.

Further, PNG states that it: "believes that this proposal is also consistent with treatment afforded these types of costs under US GAAP."

34.1 Please elaborate on why PNG believes that the proposed accounting treatment is allowed under US GAAP. Please provide the applicable US GAAP section(s) in support of this response.

34.2 Please explain if these costs are allowed to be capitalized under US GAAP. Please provide the applicable US GAAP section(s) in support of this response.

34.3 Please provide the annual revenue requirement impact for each of the five years that the asset is in service under each of the following two scenarios, broken down between income taxes, depreciation, amortization, return on equity and interest:

- Record the $565,000 overhaul costs in a deferral account in 2018 and amortize over five years when the asset is placed in service;
- Record the $565,000 overhaul costs as capital and depreciate over 5 years when the asset is placed in service.

34.3.1 Please discuss if there are any additional ratepayer benefits to recording the EMAT ILI run costs in a deferral account, rather than capitalizing them, other than the tax implications.

35.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 65
Line break costs

On page 65 of its Application, PNG states that temporary repair costs of $349,000 in 2017 and $247,000 in 2018 were recorded in the line break costs deferral account related to the Copper River line break.

35.1 Please describe the nature of the temporary repairs that were required for the Copper River line break.

36.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, pp. 68 - 69
Option Fee Payment Deferral Account

Pages 68 and 69 of the Amended Application include a history of the option Fee Payment deferral account and the specific approvals sought for Test Years 2018 and 2019, specifically:

- With the termination of the EDFT GTSA and the uncertainty of a new project in the immediate future, PNG proposes once again to defer the amortization of this Option Fee deferral account and continue to address this matter basis in its annual or biennial revenue requirements applications.

- PNG is proposing that future negotiated option fees also be recorded in this deferral account upon receipt.
- PNG proposes that GST remitted to the Canada Revenue Agency (CRA) of $321,000 be recorded in this deferral account.

36.1 Please confirm, or explain otherwise, that there are no remaining legal requirements regarding the option fees recorded in the Option Fee Payment deferral account now that both the Gas Transportation Service Agreement (GTSA) and the Interconnecting Transportation Reservation Agreement (ICTRA) are terminated. Specifically, please confirm that there are no requirements related to crediting the option fees against future charges for gas transportation services.

36.2 Please confirm when the GST of $321,000 related to the Option Fee Payments was remitted to the CRA.

36.3 In the event that no amortization for the Option Fee Payment deferral account is recorded in Test Years 2018 and 2019 as proposed, please discuss if PNG considers that the current short term interest rate applied to the deferral account is appropriate. Please discuss why or why not.

36.4 Please provide the Test Years 2018 and 2019 rate impact of amortizing the Option Fee Payment deferral account balance in full over 2018 and 2019.

36.5 Given the potential legal requirements related to future negotiated option fees as compared to the option fees recorded in the Option Fee Payment deferral account, would PNG consider it appropriate to apply for deferral account treatment of any future negotiated option fees once they are received and/or contracts are in place rather than at present? Please discuss why or why not.

37.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 70
PLP Project Amendment sharing

PNG describes its proposal regarding the PLP Project on pages 70 of the Amended Application, as follows:

> In September 2016, PNG-West and Triton LNG Limited Partnership entered into an Amendment Agreement to amend the terms of the Transportation Reservation Agreement dated July 2013 for the proposed Triton LNG Project (PLP Project). Upon execution of the amendment, PNG-West recovered all the development costs incurred on the PLP project and also recognized revenues of approximately $6.8 million related to the recovery of overhead and carrying costs. PNG-West made a decision to set aside $200,000 of the revenues recognized to be shared with its ratepayers. As such, this amount was recorded in an interest bearing deferral account. PNG-West is hereby seeking Commission approval to record this credit deferral and fully amortize it in Test Year 2019 to the benefit of ratepayers.

37.1 Please provide a description of the Triton LNG Project and how it relates to PNG, in addition to the status of the project, the Transportation Reservation Agreement and subsequent amendment(s).

37.2 Please confirm if the Transportation Reservation Agreement dated July 2013 referenced in the Amended Application, is the same agreement as was approved by Order C-10-15A.

37.2.1 Was the Amendment Agreement filed with the Commission for approval? Please explain why or why not.

37.3 Please describe the nature of the development costs, overhead costs and carrying costs incurred by PNG in relation to the Triton LNG Project.

37.4 Please provide the amount of the development costs recovered from Triton LNG Limited Partnership.

37.5 Please provide the amount of any development costs, overhead and/or carrying costs that have been included in PNG's past revenue requirements and recovered from ratepayers.

37.6 Please explain why PNG is proposing to amortize the $200,000 related to the PLP Project in 2019, as opposed to 2018.

H. MISCELLANEOUS OTHER INCOME AND CREDITS

38.0 **Reference: Miscellaneous Other Income and Credits**
Exhibit B-1-1, Sections 2.10 and 3.2.2.4, pp. 72 and 131
Other Income

On page 72 PNG provides the following table:

Table 30: Miscellaneous Operating Revenues and Credits

	$000's											
Revenue/Credit Item	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017 Change		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Penalty charges	93	0	0.0%	93	9	11.3%	84	123	104	82	88	79
Connection fees	96	-	0.0%	96	(13)	(12.1)%	110	108	92	100	111	109
Rents	-	-	n/a	-	(6)	(100.0)%	6	-	-	0	6	6
Overheads recovered	29	(0)	(0.0)%	29	(2)	(5.3)%	31	48	25	30	52	16
Commission (PST)	2	-	0.0%	2	-	0.0%	2	2	2	2	2	2
Utility charges to non-regulated business	-	-	n/a	-	-	n/a	-	-	-	42	70	54
Other	-	-	n/a	-	(5)	(100.0)%	5	10	4	3	76	2
Total	221	(0)	(0.0)%	221	(17)	(7.1)%	238	291	228	260	406	268

Source: Tab Schedules, Tab 1, Page 8

38.1 Please discuss why the forecast 2018 and 2019 penalty charges are expected to be $30,000 lower than the actual 2017 penalty charges.

I. SHARED SERVICES RECOVERY FROM PNG(NE)

39.0 **Reference: Shared Services Recovery from PNG(NE)**
Exhibit B-1-1, Sections 2.11, pp. 73-82;
PNG-West 2016-2017 RRA, Exhibit B-4, BCUC IR 28.1
Composite Allocators

On page 73 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.

39.1 Please clarify what "base costs and financial and operating metrics" mentioned in the above preamble means.

In response to BCUC IR 1.28.1 in the PNG-West 2016-2017 RRA proceeding, PNG provided the following table:

Test Year / Division	Customer Count		Employee Count		Rate Base		Composite Average w/o Time
	#	%	#	%	$	%	%
2017 Test Year							
PNG-West	20,452	49.1%	92	76.0%	135,767	65.0%	63.4%
FSJ	12,634	30.3%	14	11.6%	43,446	20.8%	20.9%
DC	7,362	17.7%	13	10.7%	25,652	12.3%	13.6%
TR	1,236	3.0%	2	1.7%	3,893	1.9%	2.2%
PNG(NE)	21,232	50.9%	29	24.0%	72,990	35.0%	36.6%
Total	41,683	100.0%	121	100.0%	208,756	100.0%	100.0%
2016 Test Year							
PNG-West	20,424	49.4%	92	76.0%	135,115	66.5%	64.0%
FSJ	12,443	30.1%	14	11.6%	40,709	20.0%	20.6%
DC	7,213	17.5%	13	10.7%	23,909	11.8%	13.3%
TR	1,241	3.0%	2	1.7%	3,457	1.7%	2.1%
PNG(NE)	20,897	50.6%	29	24.0%	68,076	33.5%	36.0%
Total	41,321	100.0%	121	100.0%	203,191	100.0%	100.0%
Decision 2015							
PNG-West	20,401	50.1%	87	75.7%	137,195	68.3%	64.7%
FSJ	12,059	29.6%	13	11.3%	37,495	18.7%	19.9%
DC	7,041	17.3%	13	11.3%	22,905	11.4%	13.3%
TR	1,256	3.1%	2	1.7%	3,156	1.6%	2.1%
PNG(NE)	20,356	49.9%	28	24.3%	63,556	31.7%	35.3%
Total	40,758	100.0%	115	100.0%	200,751	100.0%	100.0%

39.2 Please recreate the table above for each of 2016 and 2017 actuals and Test Years 2018 and 2019 forecasts.

Table 34 on page 77 of the Amended Application includes a column labelled "Test Year 2015".

39.3 Please confirm, or explain otherwise, that this column should be labelled as "Decision 2015" not "Test Year 2015".

39.4 Please recreate Table 34 by replacing the last three columns in the table with "Actual 2017", "Actual 2016" and "Actual 2015" figures.

Table 35 on page 81 of the Amended Application includes a column labelled "Test Year 2015".

39.5 Please confirm, or explain otherwise, that this column should be labelled as "Decision 2015" not "Test Year 2015".

39.6 Please recreate Table 35 by replacing the last three columns in the table with "Actual 2017", "Actual 2016" and "Actual 2015" figures.

J. RATE BASE

40.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, p. 85
Capital Expenditures 2018

PNG forecasts Total Capital Expenditures excluding overhead of $15,218,633 for Test Year 2018.

40.1 Please confirm that all the Capital expenditures planned for 2018 are still expected to be completed in 2018.

40.1.1 For each of the projects identified that is expected to extend beyond Test Year 2018, please provide the full project schedule and the total project cost, including a breakdown of the expenditures by year.

41.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, pp. 87 and 93
Planned recurring costs - new replacement tools

PNG forecast $116,000 for tools and equipment for test year 2018, and $77,000 for tools and equipment for test year 2019.

41.1 Please provide a detailed breakdown of all the costs associated with tools and equipment for Test Years 2018 and 2019.

42.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, p. 87
Planned no-recurring costs – Copper River MP 250 Repair

On page 88 pf the Application PNG states: "PNG-West has analyzed numerous alternative solutions to the repair, each with variations in design, permitting, stakeholder requirements and identified risks."

42.1 Please provide a comparison table of the alternatives that PNG considered and clearly showing the following:

- construction costs;
- the risk/probability of a repeat occurrence;
- maintenance costs;
- non-financial factors;
- overall lifecycle cost perspective;
- design specifics;
- permitting and stakeholder requirements;
- identified risks.

42.1.1 Please discuss why the current proposal was considered to be the best alternative.

42.2 Please confirm if PNG plans to submit a Certificate of Public Convenience and Necessity (CPCN) application for this project. If not, please explain why not.

42.3 Please confirm that the pipeline replacement is "like for like" in capacity and size as compared to the previous line.

42.4 Please provide the project schedule, including the commencement date, and how it is currently tracking against the schedule. Specifically, please address if the project is on track to be completed in 2018 and if construction has already commenced.

42.5 Please provide a copy of the detailed budgetary control cost estimate for the project.

42.5.1 Please provide a breakdown of the total project costs by year, including those project costs that have already been incurred.

42.5.2 Please provide a detailed breakdown of $80,000 already spent on the planning aspect of this project.

42.6 Please provide a breakdown of the total expected Contribution in Aid of Construction (CIAC) related to the repair, broken down by the party that is expected to make the contribution (i.e. insurer, BC Ministry of Forests, Lands and Natural Resource Operations (FLNRO) and other stakeholders.

42.6.1 Please provide an update on the negotiations with the FLNRO and other stakeholders and the insurer.

43.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, p. 89
Planned no-recurring costs – Ridley Island Propane Export Terminal (RIPET) Gas Supply

On page 88 of the application PNG states:

> In 2017, PNG-West received a request from its parent company, AltaGas, to provide a high pressure gas service to its RIPET facility near Prince Rupert with a required fuel gas in-service date of October 2018. The RIPET project is expected to be the first propane export terminal on Canada's west coast with a design to ship up to 1.2 million tonnes of propane per year.

43.1 Please provide the project schedule, including the commencement date, and how it is currently tracking against the schedule. Specifically, please address if the project is on track to be completed in 2018.

43.1.1 Please explain if and when construction has commenced on the new 114mm steel pipeline, new pressure regulating station and/or metering station required to provide service to the RIPET project.

43.2 Please confirm if PNG plans to submit a CPCN application for this project. If not, please explain why not.

43.3 Please provide in detail the justification and need for PNG to carry out this project.

43.3.1 Please provide details of the alternatives solutions, if any, that were considered.

43.3.2 What alternatives to PNG, if any, were considered? Specifically, did AltaGas consider constructing the RIPET project themselves? Please discuss.

43.4 Please provide a copy of the detailed budgetary control cost estimate for the project.

43.4.1 Please provide a breakdown of the total project costs by year, including those project costs that have already been incurred.

43.4.2 Please provide a detailed breakdown of the $126,000 already spent on this project.

44.0 **Reference: CAPITAL EXPENDITURES**
Exhibit B-1-1, pp. 27-28 and 88 - 89
RIPET gas supply

PNG describes the service request related to the RIPET project on pages 88 – 89 of its Amended Application, as follows:

> In 2017, PNG-West received a request from its parent company, AltaGas, to provide a high26
> pressure gas service to its Ridley Island Propane Export Terminal (RIPET) facility near

> Prince Rupert with a required fuel gas in-service date of October 2018. The RIPET project is expected to be the first propane export terminal on Canada's west coast with a design to ship up to 1.2 million tonnes of propane per year.
>
> …
>
> Approximately 2.4 kilometers of new 114mm steel pipeline will be required, along with a new pressure regulating and metering station.
>
> The total installed cost for the complete project works is estimated at $3,800,000, of which approximately $126,000 was spent in 2017 on engineering, design, and permitting aspects of the project.
>
> PNG-West and AltaGas are in the process of finalizing negotiations of a long-term Firm Sales Service Agreement. PNG-West has also entered into a backstop agreement for this project to ensure that its existing customers are not at risk during the construction phase of the project.

On pages 27 and 28 of the Amended Application PNG explains that part of the forecast increase in deliveries for 2019 over 2018 reflects: "the addition of RIPET, a new small industrial customer, expected to commence service in June 2019 under a take-or-pay contract for annual volumes of approximately 140,000 GJ."

44.1 Has a mains extension test been conducted for the capital expenditures related to the RIPET project? If yes, please provide the results of the mains extension test. If not, please explain why not.

44.2 Please explain if CIAC related to this project has been included in the Amended Application and if so, the amount. If not, please explain why not.

44.3 Please provide the current status of the long-term Firm Sales Service Agreement related to the RIPET project, and when it is expected to be finalized.

44.3.1 Please provide any details that are available regarding the long-term Firm Sales Service Agreement, including:

- Term of the Agreement;
- Minimum Take of Pay Volume;
- Applicable Rate;
- Applicable Contribution in Aid of Construction.

44.4 Please provide a copy of the "backstop agreement" for the RIPET project that is referenced on page 89 of the Amended Application.

44.5 Please reconcile the statement that a "fuel gas in-service date of October 2018" is required as compared to the statement that RIPET is expected to commence service in June 2019.

44.6 Please confirm the amount of any additions to rate base related to the RIPET project in the Amended Application and the test year in which they are added.

44.7 Please confirm the amount of any incremental revenue related to the RIPET project included in the Amended Application.

44.8 Please provide the expected annual revenue requirement impact of the RIPET project, including:

- Incremental Revenue;
- Incremental costs, including:
  - Depreciation;
  - Return on equity;

- Interest;
- Operating and maintenance costs.

45.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, pp. 89, 113, 115
Planned non-recurring costs – compressor station upgrades

PNG forecasts Total Capital Expenditures excluding overhead of $1,772,000 for compressor station upgrades for Test Year 2018.

On page 110 of the Amended Application PNG shows that in 2016 the Capital Expenditures for the compressor station upgrades was $56,000 less than approved.

On pages 114 of the Amended Application PNG shows that the 2017 Capital Expenditures for the compressor station upgrade were $277,336 less than approved. PNG states that the primary item contributing to this variance was the delay in the R1 valve overhaul due to long material lead times. PNG also cites "manufacturing issues for replacement parts".

Both underspends include delays within the project.

45.1.1 Please provide the full schedule for the compressor station upgrades and how PNG is tracking against the schedule so far in 2018.

45.1.1.1 Please discuss if PNG foresees any delays in the completion of the compressor station upgrades in 2018.

45.1.2 Please confirm if PNG has firm commitments regarding the timing of receipt of materials and replacement parts required to complete the compressor station upgrades in 2018.

45.1.3 Please discuss the measures that PNG has undertaken, if any, to mitigate long material lead times and manufacturing issues for replacement parts.

46.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, pp. 89 and 94
Planned non-recurring costs – Geographical Information System

On page 89 of the application PNG states: "PNG plans to implement a Geographic Information System (GIS) to improve its asset management capacity as it sees its current system and processes as untenable over the long term."

Further, PNG states:

> In the third quarter of 2017, PNG engaged an engineering/geomatics consultancy firm to execute a needs assessment and requirements project to support the GIS initiative. The primary motivating factors for moving forward with a GIS implementation are: (1) develop an authoritative system of record with regard to PNG's assets; (2) provide an enterprise wide system to allow PNG staff (particularly field staff) to operate much more efficiently and consistently; (3) improve integration between key business systems; (4) improve capabilities and capacity for reporting and regulatory compliance 1 (i.e. CSA standards, BC Oil and Gas Commission and Technical Safety BC regulations, Association of Professional Engineers and Geoscientists of BC (APEGBC) bylaws); and (5) incorporate contemporary industry best4 practices and technology to PNG's operations. Based on a comprehensive assessment of alternatives, PNG has plans to execute implementation recommendations over a three-year period (2018 to 2020). The overall project cost is estimated at $2.4 million, which will be incurred over three years and will be shared by PNG-West and PNG(NE) service areas.

46.1 Please include an outline of how this project is managed, and identify the parts of the project that were put out for bids on a competitive basis.

46.2 Please provide a comparison of the alternatives that were considered to the GIS project as it is proposed in the Amended Application. Please include a discussion on the pros and cons of the alternatives and why the GIS project as it was proposed was ultimately chosen as the preferred alternative.

46.3 Please confirm the engineering/geomatics consultancy firm that was used by PNG in relation to the GIS project and provide any reports that were provided by the firm to support the needs assessment and project requirements to support the GIS initiative.

46.4 Does PNG plan to file a CPCN for the GIS project? If not, please discuss why not.

46.5 Please elaborate on the need for this project, specifically in relation to the five motivating factors cited in the Amended Application.

46.6 Please provide the full project planning schedule, including the commencement date, and how it is tracking against the schedule so far in 2018. Specifically, please address if the project has commenced.

46.7 Please provide a cost schedule for the project showing annual expenditures and for each year please clearly show the cost allocation between PNG-West and PNG(NE).

47.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, p. 90
Planned non-recurring costs – Asset Record Modernization

PNG states: "This is the first phase of a multi-year program by PNG to digitize all pipeline and associated facility design and construction records."

47.1 Please clarify how many years this project will span and provide the full project planning schedule. Specifically, please address when implementation of this project will commence.

47.2 Please provide the total project costs for the Asset Record Modernization and a schedule showing expenditures by year for the project.

48.0 **Reference: Rate Base**
Exhibit B-1-1, Section 2.13.1, p. 90
Planned non-recurring costs – Automatic Meter Reading Pilot Project

48.1 Please discuss if PNG has any plans to file a CPCN for Automatic Meter Reading (AMR) following the pilot project and any associated timelines for this.

48.2 Please provide a cost schedule showing the total project costs and a breakdown of the expenditures by year.

48.3 Please list all benefits to be realized from the AMR and the associated cost savings.

48.4 What is the estimated average cost per customer to install the AMR system service, and how does this compare to the average cost for manual meter reading?

48.5 Please provide the full project planning schedule, including the commencement date, and how it is tracking against the schedule so far in 2018. Specifically, please address if the project has commenced and if it is expected to be complete in 2018. If not please clarify over how many years it will span.

49.0 **Reference:** **Rate Base**
Exhibit B-1-1, Section 2.13.2, p. 97
Post-retirement benefit plans

On page 97 PNG states:

> PNG-West notes that its 2016 pension valuation identified a solvency deficiency such that, commencing once again in 2017, there is a requirement for PNG-West to make special cash contributions to its registered pension plan.

49.1 Please elaborate further on the "solvency deficiency" mentioned in the above preamble, including the cause of the "solvency deficiency", the amount of the deficiency, the amount of "special cash contributions" forecast for Test Years 2018 and 2019 and future years, and for how many years the pension plan is expected to remain in a "solvency deficiency" position.

49.2 Please discuss PNG's plan to pay down the "solvency deficiency" and the expected time period involved.

49.3 Please identify and discuss the requirements of any regulations regarding how solvency deficiencies should be resolved (i.e. minimum pay down amounts and prescribed time periods that deficiencies should be eliminated), and PNG's compliance with such regulations.

49.4 Please discuss the implications to PNG if it is unable to pay down the "solvency deficiency" within its planned time period or the prescribed time period.

49.5 Please provide a copy of the pension valuation that was completed at December 2017.

On page 47 PNG states:

> PNG-West has an aging workforce and a preliminary analysis indicates that 50% of the employees in this department are eligible to retire in the next 5 years.

49.6 Will the expected retirements mentioned in the above preamble increase the "solvency deficiency" in the pension plan? Please discuss why or why not, and the amount of the increase in the deficiency, if applicable.

K. CAPITAL STRUCTURE AND RETURN ON CAPITAL

50.0 **Reference:** **CAPITAL STRUCTURE AND RETURN ON CAPITAL**
Exhibit B-1-1, p. 103
Credit rating assessment

On page 103 of the Amended Application, PNG states:

> For the purposes of this Amended Application for both Test Year 1 2018 and Test Year 2019, PNG-West has used the Decision 2017 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.

50.1 What is PNG's current credit rating? Has PNG's credit rating changed in the last five years?

50.2 Please provide PNG's last three credit rating reports.

51.0 **Reference:** **BUSINESS RISK ASSESSMENT**
Exhibit B-1-1, Appendix G
Business risk assessment – 2018 update

In Appendix G of the Amended Application, in compliance with Order G-77-13, PNG filed a business risk assessment update for 2018 based on a consolidated entity level for PNG-West and PNG(NE) (collectively, PNG). PNG's assessment of business risks are in the following areas: Aboriginal Rights, competitive position of natural gas, customer growth, market demand and throughput, regulatory risk, supply risk, and other risks.

On page 6 of Appendix G, PNG concludes that it does not propose any changes to its cost of capital to compensate for the increasing risk as the change has not been overly substantive at this time.

51.1 With respect to Aboriginal Rights, PNG submits that there are numerous requirements for dealing with various aspects of Aboriginal Rights representing a much more resource intensive effort, and cites recent court cases. Please provide a brief overview of these court cases.

51.1.1 If applicable, please discuss how these court cases will affect PNG's business risk in Aboriginal Rights, and in terms of more investments in resources and efforts.

51.2 With respect to competitive position of natural gas, PNG states: "[c]ommodity prices continue to be lower than 2016 and 2012, and market prices have shown less volatility in recent years." Please provide the PNG-West commodity rates for PNG-West and Granisle propane service areas from 2011 to present.

51.2.1 Please provide supporting quantitative evidence to substantiate that "market prices have shown less volatility in recent years."

51.2.2 PNG notes that the competitive position of natural gas has not improved. Please confirm that PNG in this statement is referring to the more expensive upfront installation costs, and carbon tax associated with natural gas service, and not natural gas rates in comparison with electricity. If not confirmed, please explain.

L. CAPITAL EXPENDITURE REPORTING

52.0 **Reference:** **Other Matters**
Exhibit B-1-1, Section 3.1.1, p. 109
Capital expenditures variance analysis

In Table 44 PNG identify several projects with variances in excess of $50,000.

52.1 Please explain if there are any overarching reasons why PNG has several projects in 2017, with a capital expenditure variance greater than $50,000.

52.2 To what extent has PNG considered the larger capital variances in 2016 and 2017 and applied the necessary adjustment when budgeting for the 2018/2019 capital projects?

52.2.1 Please populate the table below and provide a detailed reason for any variances that exceed $50, 000 between the 2017 actual costs and 2018 budgeted costs.

Major Capital Projects	2017 Approved Expenditure Excluding Overhead	2017 Actual Expenditure Excluding Overhead	2018 Budgeted Cost Excluding Overhead
Mobile/Heavy Equipment Investigative Dig Cut-outs New Services Unspecified Mainline Repairs New/Replacement Tools and Equipment Computing Hardware/Software Meter and Regulator Purchases Distribution Mains Transmission Mainline Repairs and Assessments Structure Improvements Replace Line Heaters Compressor Station Upgrades Meter & Regulating Station Upgrades			

M. COST OF SERVICE VARIANCE REPORTING

53.0 **Reference: Cost of Service Variance Reporting**
Exhibit B-1-1, Section 3.2, pp. 118-131
Actual 2016 vs Decision 2016 and Actual 2017 vs Decision 2017

53.1 Please revise Tables 48, 51 and 52 to remove the disallowed costs from the Actual 2016 and 2017 amounts.

53.2 Please provide a revised explanation of the variance between Actual 2016 and 2017 and Decision 2016 and 2017, respectively, for administration expenses (Account 721) based on the revised tables.

53.3 What are PNG's Actual 2016 and 2017 revenue deficiency, and return on equity compared to Decision 2016 and 2017 after removing the disallowed costs from the actuals. Please show calculations and explain any assumptions.

N. IDENTIFIED SERVICE QUALITY METRICS

54.0 **Reference:** **Identified Service Quality Metrics**
Exhibit B-1-1, Section 3.3, p. 132
Key service quality metrics

On page 132 PNG provided the following table:

Table 56: Key Service Quality Metrics

Service Quality Metric	2017	2016	2015	2014	2013
Number of Emergency Calls	301	417	410	328	366
Average Response Time per Call	19 minutes	15 minutes	18 minutes	19 minutes	18 minutes
Number of Calls with a Response Time over 40 Minutes	39	35	52	46	42
Number of Underground Leaks	27	15	11	18	11
Number of Reportable Environmental Incidents	–	–	1	–	–
Lost-time Injury Frequency Rate *	2.07	2.84	1.01	1.19	–
Customer Complaints to the BCUC **	2	0	3	3	2

* Reflects PNG consolidated rate; not tracked by individual service area
** Information reflects Commission's March 31 fiscal year end (i.e. data for 2017 is from April 1, 2016 to March 31, 2017)

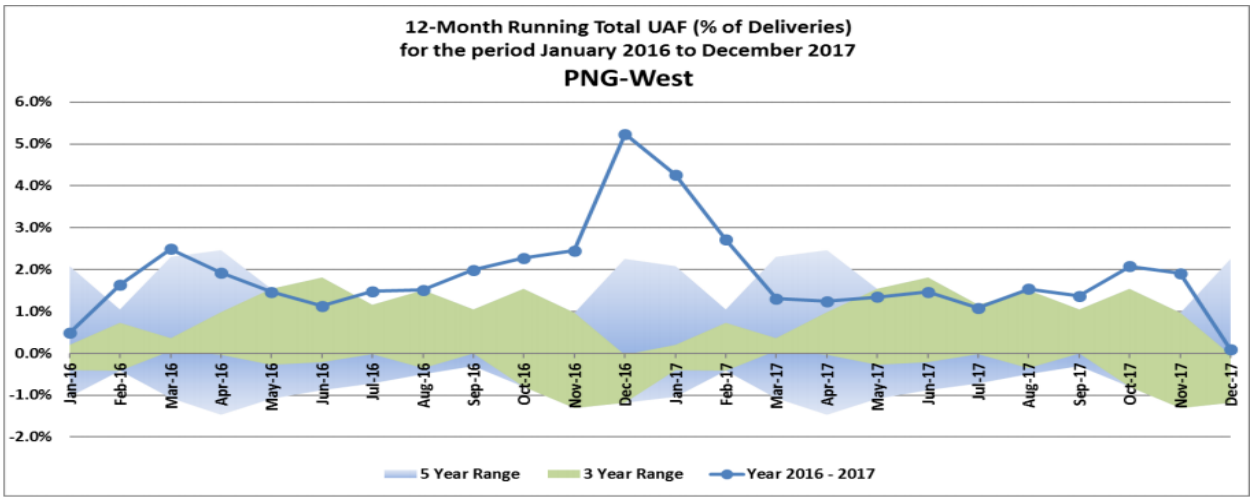
54.1 Are there specific benchmarks that PNG works towards with respect to the key service quality metrics provided in the table above? If not, please explain why not.

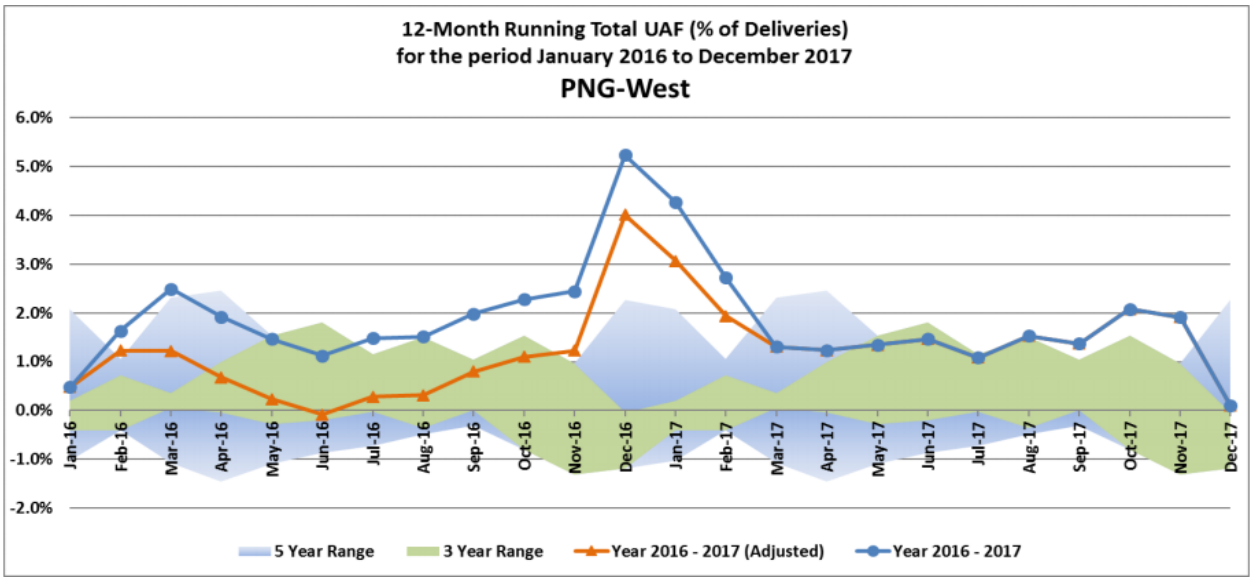
54.1.1 If so, please provide these benchmarks.

O. OTHER MATTERS TO BE ADDRESSED FROM PRIOR YEAR DECISIONS

55.0 **Reference:** **DEMAND FORECAST, REVENUE AND MARGIN**
Exhibit B-1-1, Section 2.2.3, pp. 30-31. Appendix B, Figure 1 & Figure 3, pp. 4-6
Unaccounted for gas

On page 4 of Appendix B, referring to Figure 1, PNG states: "The blue and green shaded areas represent the range of 12-month running total UAF during the periods 2013-2015 and 2011-2015, respectively."





On page 5 of Appendix B, PNG states:

> A determination of the monthly UAF volume is dependent upon an unbilled estimate; in other words, an estimate of the volume of natural gas delivered, but not yet billed to customers. This amount is estimated based on the number of unbilled days of service (DOS) from when a customer was last billed, to the end of the current calendar month…The change in reporting resulted in a reduction in the estimate of unbilled consumption of residential customers, and a resultant increase in the monthly UAF loss, during the months of February and March 2016.

55.1 Please confirm that the blue shaded area in Figures 1 and 3 represent the 5 year range and green represents the 3 year range.

55.2 Please explain how PNG estimates the volume of natural gas delivered but not yet billed to customers.

55.3 Please explain how UAF is correlated to the estimate of the volume of natural gas delivered.

55.4 Please confirm, or explain otherwise, that a reduction in the estimate of unbilled consumption results in a <u>decrease in the monthly UAF loss, as shown by the orange line in Figure 3, and not an increase as stated in the above preamble.</u>

55.5 What change did PNG implement in February 2016, in the way unbilled days of service (DOS) were reported?

55.5.1 Why did this change result in the reduction in the estimate of unbilled residential customers?

55.5.2 Why did this change only impact unbilled residential customers? Were commercial and industrial customers unaccounted for gas (UAF) volumes affected by this change?

55.6 Please provide a graph, showing the estimate of the volume of gas delivered relative to the actual delivered volume by month and customer classification from January 2016 onwards.

55.7 Why did the change in unbilled DOS only affect February and March 2016? Please explain.

55.7.1 Why was the largest adjustment made to the March 2016 volume, both in absolute terms and relative to the total?

55.8 Even after the adjustment, the 2016-2017(Adjusted) UAF volumes in February and March 2016, are above February and March levels found in the 12 month running total UAF during the periods 2013-2015. What other factors, if any, has PNG identified that could cause the UAF to be larger during this period?

55.9 Prior to the adjustment please explain why 2016-2017 UAF volumes are greater than or equal to 3 year range (green) from July 2016 until May 2017. Why is there an upwards trend in UAF volumes month over month from August 2016 to the peak UAF volume observed in December 2016?

On page 6 of Appendix B, PNG states: "PNG has determined that the most likely cause of the significant UAF volume during December 2016 is a residential and small commercial unbilled estimate that did not correctly reflect the impact of the sudden and significant cold snap that occurred during the middle of December."

On page 8 of Appendix B, PNG further states that:

> 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. In an effort to improve its unbilled estimate under these circumstances, PNG continues to evaluate the costs and benefits of accessing more accurate customer information, such as may be provided using advanced metering infrastructure (AMI), or through a renewed residential end-use survey (REUS).

55.10 How did PNG determine that a sudden and significant cold snap was the most likely cause of the significant volume in December 2016? Please provide details of this analysis.

55.10.1 How can PNG isolate weather related and non-weather related effects which may jointly result in the significant December 2016 UAF volume?

55.10.2 Does PNG assign probabilities to likely cold weather events, similar to the one observed in December 2016, from occurring again in the future? If so, please provide details. If not, how could this analysis be implemented?

55.11 Please confirm, or otherwise explain, that the December 2016 unbilled estimate was included as an adjustment based on actual deliveries and billed on a subsequent billing cycle.

55.12 What measures do PNG have in place to ensure customers are billed accurately?

55.13 Please explain the reason(s) why UAF levels, after adjustment, lay outside the 2 and 5 year bounds for September to November 2017.

55.14 Has PNG experienced a significant weather related UAF volume prior to December 2016? If so, please provide a detailed analysis on when this occurred. If not, why was December 2016 the first occurrence?

55.15 What measures, if any, are in place to mitigate the effects this isolated event has on UAF volumes?

55.16 What are the associated costs and benefits to PNG of accessing more accurate customer information? Please provide any financial and/or UAF volume analysis PNG has performed.

55.17 Is PNG likely to implement solutions to access more accurate customer information in the future? If so, how would PNG achieve this and how would associated costs be recovered?