bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

April 26, 2018

Sent via eFile

PNG WEST 2018-2019 REVENUE REQUIREMENTS
EXHIBIT A-9

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. 2

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. 2. Please file your responses electronically by Thursday, May 10, 2018.

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/yl

Enclosure

bcuc
British Columbia
Utilities Commission

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

P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

Pacific Northern Gas Ltd.
2018–2019 Revenue Requirements Application

INFORMATION REQUEST NO. 2 TO PNG

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A. DEMAND FORECAST REVENUES AND MARGIN

56.0 **Reference: Demand Forecast, Revenue and Margin**
Exhibit B-1-1, Section 2.1, pp. 25-28; Exhibit B-3, BCUC IR 4.13
Industrial Deliveries

In British Columbia Utilities Commission (BCUC) Information Request (IR) 4.13 Pacific Northern Gas Ltd. (PNG) states that BC Hydro's demand will be much greater than 24,000 GJ for 2018, due to a downed transmission line between Terrace and Prince Rupert as a result of an avalanche in March 2018.

PNG further states that the forecast credit additions proposed to the Industrial Customers Delivery Deferral Account (ICDDA) deferral account for this event are approximately $320,000 to date.

56.1 Please provide the status of the transmission line, including whether it has been repaired and if so when it became operational again?

56.1.1 Please provide the dates and associated actual gas deliveries for the period where the Prince Rupert generating station was providing backup power.

56.1.2 If the transmission line has not yet been repaired, please also provide the anticipated date at which the Prince Rupert generating facility reverts to its normal standby operations and the actual and forecast gas deliveries the Prince Rupert generating facility requires to provide backup power.

56.2 Please provide detail as to how PNG calculated that forecast ICDDA credit additions are approximately $320,000 to date as a result of this event.

56.2.1 Please clarify if PNG is proposing to include the incremental volumes from March 2018 in the ICDDA as opposed to including them in the demand forecast. If confirmed, please explain why PNG is not proposing to include these amounts in the demand forecast.

PNG states that, "In February 2018, bad weather also played a role in PNG experiencing a transmission line break in a remote area between Terrace and Prince Rupert…PNG has recently finalized the cost of trucking in LNG to Prince Rupert during the line break and the forecast debit additions to the deferral account are approximately $146,000."

56.3 Please explain how bad weather lead to the line break and discuss any other factors that may be responsible for this event.

56.3.1 Please provide an estimate of the volume of gas leakage from PNG's system as a result of this line break.

56.3.2 Please explain what effect this event has on PNG's calculation of unaccounted for gas (UAF) for February 2018.

56.4 Please provide a cost breakdown of the forecast $146,000 debit additions to the deferral account associated with the liquefied natural gas (LNG) required for Prince Rupert during the line break, including the commodity and transportation cost.

B. OPERATING AND MAINTENANCE EXPENSES

57.0 **Reference: Operating Expenses**
Exhibit B-3, BCUC IR Nos. 1.7.1, 1.7.3 and 1.7.4
Account 665 – Pipelines

In response to BCUC Information Request (IR) 1.7.1, PNG states:

> PNG notes that additional costs are forecast to be incurred in Test Year 2018 for all of the carryover activities, including:
>
> - Forecast costs for the temporary repairs for the Kleanza Creek washout are $45,000.
> - Forecast costs for the temporary repair of the Copper River washout are $210,000.
> - Forecast cost for ongoing integrity management plan improvements are $118,000.
>
> PNG notes that there are no costs for any of the reference activities forecast for Test Year 2019.

57.1 Please identify the accounts in the table provided in response to BCUC IR 1.7.3, and amounts that the above costs for 2018 have been recorded to.

57.2 Please explain why Test Year 2019 costs for "Pipelines" (Account 665) are forecast to increase by $33,000 over Test Year 2018 when there are no costs related to the items in the above preamble forecasted for Test Year 2019.

The table provided in response to BCUC IR 1.7.3, shows the following for Close Interval Surveys (CIS)/DCVG:

- Actual 2016: $69,000
- Decision 2016: $54,000
- Actual 2017: $75,000
- Decision 2017: $16,000
- Test Year 2018: $122,000
- Test Year 2019: $122,000

In response to BCUC IR 1.7.4, PNG states:

> Close Interval Surveys (CIS)/DCVG
>
> - Actual 2016 vs Decision 2016
>
> Level of effort required by both PNG and the survey contractor was considerably greater than forecast for Decision 2016. This was due primarily to site access requirements not originally expected and the need to conduct survey on additional pipelines not included in the rate application in order maintain compliance with our Integrity Management Plan CIS/DCVG survey frequency.
>
> - Actual 2017 vs Decision 2017
>
> Level of effort required by both PNG and the survey contractor was considerably greater than forecast for Decision 2017. This was due primarily to site access requirements not originally expected.

- Test Year 2018 vs Decision 2017

  Significantly greater level of effort required for completion of the surveys planned for 2018 relative to Decision 2017 and Actual 2017 due to overall length of pipelines to be surveyed and access requirements including private land owner considerations.

57.3 Please discuss why there was a significant increase in site access requirements and the need to conduct a survey on additional pipelines in fiscal 2016 and 2017 that were not anticipated during the F2016-F2017 Revenue Requirements Application (RRA) proceeding.

57.4 Please discuss the likelihood of significant variances in Test Years 2018 and 2019 forecast compared to actual due to site access requirements and pipeline surveys.

57.5 Please further elaborate on why Test Years 2018 and 2019 costs are expected to increase by $47,000 or 63 percent compared to Actual 2017. Please include the length of the pipelines planned to be surveyed in Test Years 2018 and 2019 compared to Actual 2017, and the expected differences in access requirements for the surveys planned for the Test Years compared to Actual 2017.

57.6 Please discuss the responsibilities for access allowances outlined in PNG's Terms and Conditions.

57.6.1 Please discuss the costs that the customer or private landowner is responsible for incurring with respect to access requirements.

57.6.2 Please discuss if PNG has the right to charge back its customers or private landowners the additional costs incurred when rights of way or access was denied.

The table provided in response to BCUC IR 1.7.3, shows the following for Airborne Laser Methane Assessment:

- Actual 2017: n/a
- Decision 2017: $104,000
- Test Year 2018: $101,000
- Test Year 2019: $103,000

In response to BCUC IR 1.7.4, PNG states:

Airborne Laser Methane Assessment

The Actual 2017 vs Decision 2017 variance arose due to PNG opting to complete the leak detection via line patrols therefore not requiring the airborne laser methane assessment option.

57.7 Please explain why PNG opted to complete the leak detection via line patrols instead of the airborne laser methane assessment option in 2017.

57.7.1 Please confirm, or explain otherwise, that the airborne laser methane assessment option instead of the line patrols option is planned for Test Years 2018 and 2019. If confirmed, please explain why.

57.7.2 What was the cost of the line patrol incurred in 2017 and in which account(s) in the table provided in response to BCUC IR 1.7.3, was the cost recorded to?

57.7.3 Under the scenario that PNG were to choose the line patrol option for Test Years 2018 and 2019, what would be the forecast cost of the line patrol option for those test years compared to the airborne laser methane assessment option?

57.8 Please discuss the possibility of the leak detection activities planned for Test Years 2018 and 2019 being deferred to a future test period.

58.0 **Reference: Operating Expenses**
Exhibit B-3, BCUC IR Nos. 1.8.4, 1.8.7, 1.9.1, 1.9.2, 1.9.5 and 1.9.6
Account 666 – Compressors

In response to BCUC IR 1.8.4, PNG provided the following labour costs:

- Test Year 2019: $205,000
- Test Year 2018: $201,000
- Actual 2017: $277,000
- Actual 2016: $285,000

In response to BCUC IR 1.8.7, PNG states:

> In 2016, PNG had the equivalent of 3 station operators, allowing for one retiree and two new starters. During 2017, PNG had 3 full time station operators. For 2018, it is forecast that PNG will have the equivalent of 2.3 station operators. For 2019 it is forecast that PNG will have two full-time station operators.

58.1 Please explain why there is a $4,000 increase in labour costs in Test Year 2019 over 2018 considering that there are fewer FTEs.

In response to BCUC IR 1.9.1, PNG states:

> Each of the activities listed will commence and conclude in 2018, with sustained annual operating expenses related to these activities for each future test year in order to maintain progress towards and alignment with contemporary industry standards.

58.2 Please provide the forecast annual cost to sustain the digital data mapping for Test Year 2019 and how these amounts are determined.

In response to BCUC IR 1.9.6, PNG states:

> Auto
>
> PNG generates its Auto cost forecast on a consolidated basis and allocates amounts to PNG-West and the PNG(NE) divisions on a prorate basis on O&M and Capital labour costs. On consolidated basis PNG had looked at the average spend on vehicles due to positive budget variances in 2016 and 2017 and has made use of the 2016 Actual costs inflated by 2% as the consolidated forecast for Test Year 2018.
>
> Overall Auto costs have decreased from Decision 2016 and Decision 2017 mainly from reduced maintenance costs by performing equipment service on the vehicles internally as opposed to outsourcing it out.

58.3 Please explain why PNG inflated the 2016 Actual costs by 2 percent instead of inflating the 2017 Actual costs.

58.3.1 Please explain why it would not be more accurate to inflate the 2017 Actual costs by 2 percent to calculate the consolidated forecast for Test Year 2018.

58.4 If the 2017 actual costs were inflated by 2 percent to calculate the consolidated forecast, what would the forecast Auto expenses be for Test Years 2018 and 2019 for PNG West and the PNG(NE) divisions? Please provide a breakdown of the consolidated forecast by division and by operating and capitalized Auto amounts for each of the test years.

58.5 Please confirm, or explain otherwise, that the methodology used to allocate Auto costs to PNG-West and the PNG(NE) divisions is the same as the methodology used in the 2016-2017 RRA.

In response to BCUC IR 1.9.2, PNG states:

> The Records Clerk position is expected to commence in the third quarter of 2018. The forecast cost of this position is $66,296 in wages, of which $53,801 is included in BCUC 685 and $12,495 in BCUC 688.

In response to BCUC IR 1.9.6, PNG states:

> Labour (incl bonus)
>
> The 2016 and 2017 actual to approved variances were primarily a result of vacant positions that we had for a number of months throughout the year due to replacement of personnel as well as lower starting salaries for less senior replacements. The Test Year 2018 vs Decision 2017 variance is primarily due to new Engineer and Records Administration positions. The Test Year 2019 vs Test Year 2018 variance is primarily due to inflation.

In response to BCUC 1.9.5, PNG provides the following costs for "Labour (incl bonus):

- Actual 2016: $1,809,000
- Actual 2017: $1,901,000
- Decision 2017: $1,947,000
- Test Year 2018: $2,214,000
- Test Year 2019: $2,276,000

58.6 Please provide the annualized forecast cost of the Records Clerk position and the Engineer position.

58.7 Please provide the expected start date of the new Engineer position.

58.8 Please provide a breakdown of the $267,000 variance between Test Year 2018 and Decision 2017, including the amount of variance due to lower starting salaries for less senior replacements, the new Engineer position, the new Records Administration position, and annual increases in salaries.

59.0 **Reference: Operating Expenses**
Exhibit B-3, BCUC IR 8.3, 8.4, 8.4.1
Account 666 – Compressors

In its response to BCUC IR 8.4 PNG states that it, "…does not cost relief valve testing work separately so it is unable to provide that information."

In its response to BCUC IR 8.4.1, PNG states:

> Actual contractor charges for 2016 increased over forecast amounts as, following a regulatory inspection by Technical Safety BC, PNG become aware of a requirement to test all relief valves, including those at the dormant stations, which had not been factored in the budgetary process.

59.1 Please explain why PNG does not cost relief valve testing separately and describe how it budgets and accounts for these expenses.

59.2 Following the regulatory inspection by Technical Safety BC, how many more relief valves were required to be tested than originally anticipated?

59.2.1 By how much did this requirement increase the cost of relief valve testing?

60.0 **Reference:** **Operating Expenses**
Exhibit B-3, BCUC IR No. 1.9.7; Exhibit B-1-1, Tab 1, p. 2
Operating Labour

In response to BCUC IR 1.9.7, PNG provided the following tables:

Table BCUC 1.9.7 - PNG-West - Operating Labour

Account and Description ($'s)	Test Year 2019	Change	Test Year 2018	Change	Actual 2017	Change	Decision 2017	Change	Actual 2016	Change	Decision 2016
660 Supervision	44,271	868	43,403	(22,000)	65,403	12,837	52,566	(28,156)	80,722	29,358	51,364
664 Communications	2,747	54	2,693	(420)	3,113	2,510	603	(1,834)	2,437	1,847	590
665 Pipelines	619,631	11,750	607,881	21,014	586,867	(78,675)	665,542	15,403	650,139	(961)	651,100
666 Compressors	204,875	4,017	200,858	(76,080)	276,938	86,657	190,281	(94,798)	285,079	9,425	275,654
667 Regulating stations	150,815	2,957	147,858	1,704	146,154	9,715	136,439	(6,058)	142,497	9,178	133,319
Total transmission	**1,022,339**	**19,646**	**1,002,693**	**(75,782)**	**1,078,475**	**33,044**	**1,045,431**	**(115,443)**	**1,160,874**	**48,847**	**1,112,027**
670 Supervision	350,203	6,866	343,337	(20,068)	363,405	42,286	321,119	(30,489)	351,608	37,831	313,777
673 Removing & resetting meters	328,601	6,443	322,158	15,412	306,746	(99,725)	406,471	28,122	378,349	(19,537)	397,886
674 Service on customer premises	70,492	1,382	69,110	31,347	37,763	(26,204)	63,967	16,829	47,138	(15,366)	62,504
675 Mains and services	281,419	5,518	275,901	(10,320)	286,221	(7,188)	293,409	(82,289)	375,698	88,998	286,700
677 Regulating stations	6,771	132	6,639	2,494	4,145	(2,342)	6,487	3,822	2,665	(3,674)	6,339
Total distribution	**1,037,486**	**20,341**	**1,017,145**	**18,865**	**998,280**	**(93,173)**	**1,091,453**	**(64,005)**	**1,155,458**	**88,252**	**1,067,206**
684 Communications	336	7	329	329	-	(322)	322	322	-	(314)	314
685 General systems operations	2,275,989	61,703	2,214,286	332,263	1,882,023	(64,661)	1,946,684	137,541	1,809,143	(91,629)	1,900,772
688 Other general operations	1,251,976	24,581	1,227,395	(117,496)	1,344,891	148,537	1,196,354	(206,143)	1,402,497	206,454	1,196,043
Total general	**3,528,301**	**86,291**	**3,442,010**	**215,096**	**3,226,914**	**83,554**	**3,143,360**	**(68,280)**	**3,211,640**	**114,511**	**3,097,129**
700 Sales supervision	4,005	79	3,926	(15,487)	19,413	15,470	3,943	2,202	1,741	(2,112)	3,853
Total sales	**4,005**	**79**	**3,926**	**(15,487)**	**19,413**	**15,470**	**3,943**	**2,202**	**1,741**	**(2,112)**	**3,853**
711 Customer contracts	436,902	8,567	428,335	4,858	423,477	21,081	402,396	(11,492)	413,888	20,693	393,195
712 Meter reading	294,450	5,774	288,676	41,662	247,014	(36,118)	283,132	55,818	227,314	(48,635)	275,949
713 Customer billing	310,406	16,748	293,658	22,628	271,030	(10,369)	281,399	26,268	255,131	(19,834)	274,965
714 Credit and collections	42,240	829	41,411	23,366	18,045	(23,420)	41,465	13,608	27,857	(12,660)	40,517
Total customer accounting	**1,083,998**	**31,918**	**1,052,080**	**92,514**	**959,566**	**(48,826)**	**1,008,392**	**84,202**	**924,190**	**(60,436)**	**984,626**
Total operating labour	**6,676,129**	**158,275**	**6,517,854**	**235,206**	**6,282,648**	**(9,931)**	**6,292,579**	**(161,324)**	**6,453,903**	**189,062**	**6,264,841**

Actual 2016

	Amended Application	Capitalized Labour	STIP Expense	Restated
Tab 1, Page 2, Line 2 - wages	6,748	(526)	235	6,457
Tab 1, Page 2, Line 6 - other	4,211	526	(235)	4,502
	10,959	-	-	10,959

Actual 2017

	Amended Application	Capitalized Labour	STIP Expense	Restated
Tab 1, Page 2, Line 2 - wages	6,770	(741)	255	6,285
Tab 1, Page 2, Line 6 - other	4,483	741	(255)	4,968
	11,253	-	-	11,253

Tab 1, page 2, line 2 – "wages" shows the following:

Line No.	Description	Test Year 2019	Test Year 2018	Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
1	OPERATING EXPENSES								
2	- wages	6,661	6,512	6,288	6,770	6,748	6,125	5,589	5,334

60.1 Please reconcile the balances in Tab 1, page 2, line 2 as restated in the response to BCUC IR 1.9.7 with the "Total operating labour" balances in the above table for Actuals 2016 and 2017, Decision 2017, and Test Years 2018 and 2019.

61.0 **Reference:** **Operating Expenses**
Exhibit B-1-1, Sections 2.3.7 & 3.2.2.1, pp. 36 & 127; Exhibit B-3, BCUC IR No. 1.10.1
Account 711/713/714 – Customer Care

On page 127 of the Amended Application, 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 of the Amended Application, 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.

In response to BCUC IR 1.10.1, PNG states:

> Actual contract costs for the customer billing system in 2017 were $562,887. Forecast costs for Test Year 2018 are $576,268, a decrease of 2%.

61.1 Please complete the following table for 711/713/714 – Customer Care:

	Test Year 2019	Test Year 2018	Actual 2017	Decision 2017
Customer billing system		$576,268	$562,887	
Other		$208,732	$131,113	
Total		$785,000	$694,000	$754,000

61.1.1 Please explain the significant variances in the response to the preceding IR that is not caused by inflation between Test Years 2019 and 2018, Test Year 2018 and Actual 2017 and Actual 2017 and Decision 2017 for "Other."

61.2 Please explain why the forecast costs for Account 711/713/714 – Customer Care for Test Years 2018 and 2019 should not be the 2017 Actual cost and the Test Year 2018 forecast adjusted by inflation, respectively.

62.0 **Reference:** **Operating Expenses**
Exhibit B-3, BCUC IR 9.4
Account 685 – General Operations

In its response to BCUC IR 9.4, PNG states:

> The vehicle cost allocation for BCUC 685 has increased due to the shift in O&M labour vs Capital labour resulting from increased O&M activities forecast for Test Year 2019. Please see the table below.

	2019TY	2018TY	Variance
Auto allocation West-O&M	$ 469,453	$ 431,947	$ (37,506)
Auto allocation West -Capital	83,281	142,449	$ 59,168
	$ 552,734	**$ 574,396**	$ 21,662
% Allocation of Total Labour			
O&M	*89%*	*83%*	*-6%*
Capital	*11%*	*17%*	*6%*
	100%	*100%*	

62.1 Please describe the methodology for allocating vehicle costs between capital and O&M, and provide a detailed calculation of the "% Allocation of Total Labour" for Test Years 2018 and 2019.

62.1.1 Please confirm that the allocation methodology used for Test Years 2018 and 2019 is the same as the methodology used in the 2016-2017 RRA Application. If not confirmed, please describe the differences and explain the reasons for changing the methodology.

63.0 **Reference:** **Maintenance Expenses**
Exhibit B-3, BCUC IR 12
Account 866 – Compressors

In response to BCUC IR 12.2 PNG states:

Cost Element	Test Year 2018	Actual 2017
Contractors	$35,900	$1,700
Labour	2,900	500
Supplies	1,600	200
Travel	900	-
Total	$41,300	$2,400

PNG notes that the Actual 2017 costs are artificially low due to a new manager coming on board and not being fully familiar with the different coding regimes for the compressor costs. Specifically, Account 666 Compressors is over-budget for contractors by $36,000, which offsets the majority of the variance in Account 866. This coding issue has been resolved moving forward.

The budget for Test Year 2018 was constructed using indicative costs for the previous years as well as a $20,000 provision for dealing with a compressor engine change out, should it be required.

63.1 Please provide the rationale for budgeting the amount of $20,000 for a potential compressor engine change out.

63.1.1 What is the probability that a compressor engine change will be required?

63.1.2 If a compressor engine change should be required, what is the probability that the full $20,000 provision will be required to cover the cost of the work to be completed?

C. ADMINISTRATIVE AND GENERAL EXPENSES

64.0 **Reference:** **Administrative and General Expenses**
Exhibit B-1-1, pp. 45-46; Exhibit B-3, BCUC IR No. 1.16.6
Account 722 – Special Services

In response to BCUC IR 16.6, PNG provides the following costs for "Business development services":

- Test Year 2019: $120,000
- Test Year 2018: $117,000
- Decision 2017: $105,000
- Actual 2017: $51,950
- Actual 2016: $27,119

On pages 45-46 of the Amended Application, PNG states:

> Business development and government relations consulting fees for Test Year 2018 are forecast to be $21,000 greater than Decision 2017 in anticipation of increased consultation and engagement activity with government and industry on climate change policies and initiatives such as renewable natural gas (RNG) and the proposed federal clean fuel standards. The increase for Test Year 2019 is due to inflation.

64.1 Please explain the variance between Test Year 2018 and Actual 2017.

64.2 Please explain why the forecast cost for Test Year 2018 should not be $63,950 ($51,950 Actual 2017 + $12,000 variance between Decision 2017 and Test Year 2018 for "increased consultation and engagement activity…on climate change policies and initiatives").

65.0 **Reference: Administrative and General Expenses**
Exhibit B-3, BCUC IR No. 1.17.5
Account 725 – Employee Benefits

In response to BCUC IR 1.17.5, PNG states:

> While the reduction of the discount rate applied in the actuarial valuation (3.81% to 3.60%) has an adverse impact on DB and NPPRD costs for Test Year 2018 and Test Year 2019, this is more than offset by actuarial gains in the plans recognized at the end of 2017.

65.1 Please explain what caused the actuarial gains in the plans recognized at the end of 2017.

66.0 **Reference: Administrative and General Expenses**
Exhibit B-3, BCUC IR Nos. 1.14.1 and 1.17.8
Employees by department/function

In response to BCUC IR 1.14.1, PNG provides the following table:

Number of Account 721 "Admin" Positions				
Departments/Functions	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
Human Resources	3	3	3	3
Corporate - President	2	2	2	2
Vice President Operations & Engineering	1	1	1	1
Finance & Business Development (incl. acct & treasury)	9	9	9	9
Regulatory Affairs & Gas Supply & CIS	4	4	4	4
Treasury & Corporate Development (now Finance)	0	0	0	0
IT Services	3	3	3	3
Total (Non-Bargaining)	22	22	22	22

Number of Operating & Maintenance Positions (incl 713 Head Office Positions)				
Departments/Functions	Test Year 2019	Test Year 2018	Actual 2017	Actual 2016
Operations - Non bargaining	14	14	13	12
Operating & Maintenance - Bargaining Unit	56	56	55	55
Total	70	70	68	67

In response to BCUC IR 1.17.8, PNG provides the following information:

There were eleven (11) actual vacancies at various times during 2017. From those actual vacancies, three (3) were forecast. These positions have been filled as follows:

Position (Department):	Forecast?	Date Filled:	Reason:
Budgeting Analyst (Finance)	Yes	To be determined	New
VP, Operations and Engineering	Yes	Mar-17	New
Financial Analyst (Finance)	No	Jun-17	Replacement
Executive Assistant (President)	No	Jan-17	Replacement
Senior Financial and Taxation Accountant (Finance)	No	Feb-18	Replacement
HR Generalist (Human Resources)	No	Oct-17	Replacement
Manager IT (Information Technology)	No	2018 Q3	Replacement
Project Engineer (Non Bargaining O&M)	No	Oct-17	New
Accounts Payable (Union O&M)	No	Apr-17	Replacement
Manager, Planning and Regulatory (Finance)	Yes	Jan-18	Replacement
Draftsperson (Union O&M)	No	Mar-18	Replacement

66.1 Please provide the number of Full-Time Employees (FTEs) for PNG for Test Years 2018 and 2019, Actuals 2016 and 2017, and Decision 2016 and 2017 broken down by Department/Functions and expense categories (i.e. operating, maintenance and administrative and general expense).

66.2 Please confirm, or explain otherwise, that the new "Budgeting Analyst (Finance)" position is forecast to be hired in the test period.

66.2.1 If confirmed, please discuss when in the test period the "Budgeting Analyst (Finance)" is expected to be hired and identify the amount and percentage of annual salary and benefits that have been forecast in each of the test years.

66.2.2 If confirmed, please explain why the number of positions for "Finance & Business Development" is unchanged for all years in the above table.

66.3 Please explain why the number of positions for "Vice President Operations & Engineering" is unchanged from 2016 to 2017 in the above table when this is a new position that was filled in 2017.

66.4 Please confirm, or explain otherwise that the wages and benefits for the Senior Financial and Taxation Accountant, the Manager of IT and the Draftsperson in the above table have only been forecast for the test period from February 2018, the 3rd quarter of 2018 and March 2018 onwards, respectively.

66.5 Please provide a table with the actual and BCUC approved amounts for wages and benefits for the past five years (2013 to 2017) broken down by BCUC account for each of operating, maintenance and administrative expenses. Please ensure the amounts agree to the amounts on Tab 1, page 2 of the Amended Application (lines 2, 9, 13 and 14) and BCUC IR 1.9.7.

D. INTER-AFFILIATE CHARGE

67.0 **Reference:** **Inter-Affiliate Charge**
Exhibit B-3, BCUC IR No. 1.19.5
AltaGas inter-affiliate charges

In response to BCUC IR 1.19.5, PNG states:

> AltaGas clarifies that the corporate insurance premium has historically been included in the same corporate services cost pool of Finance/Treasury. The corporate insurance premium has previously been included in Finance and was reassigned to Treasury for Test Years 2018 and 2019, with a modest year-over-year increase of approximately $0.1 million.

67.1 Please confirm, or explain otherwise, that the inclusion of the corporate insurance premium in Treasury instead of Finance for Test Years 2018 and 2019 has no impact on the inter-affiliate charge amount.

67.1.1 If not confirmed, please provide the inter-affiliate charge that would have been calculated had the corporate insurance premium been included in Finance. Please also provide a comparison of this amount with the current amount.

67.1.2 If not confirmed, please explain why the corporate insurance premium is included in Treasury instead of Finance for Test Years 2018 and 2019. Please also discuss if the corporate insurance premium is expected to be allocated to Treasury in subsequent test years. Why or why not.

E. TRANSFERS TO CAPITAL

68.0 **Reference:** **Transfers to Capital**
Exhibit B-1-1, pp. 49 and 55; Exhibit B-3, BCUC IR Nos. 1.20.1, 1.20.2 and 1.20.4
Transfers to Capital (Capitalized Overhead)

In response to BCUC IR 1.20.1, PNG provides the following table:

Table BCUC 1.20.1 - Estimated Time on Forecast Capital Activities

	% Time on Capital Activities			
	Test Year 2019	Test Year 2018	Decision 2017	Decision 2016
Executives				
President	0.0%	0.0%	27.5%	27.5%
VP Operations & Engineering	41.5%	41.5%	80.0%	80.0%
VP Regulatory & Gas Supply	5.0%	5.0%	5.0%	5.0%
VP Finance	0.0%	0.0%	0.0%	0.0%
VP HR & Government Relations [1]	n/a	n/a	0.0%	0.0%
Management				
Regional Operations (West)	35.0%	35.0%	35.0%	30.0%
Customer Service	0.0%	0.0%	0.0%	0.0%
Marketing & Lands	57.5%	57.5%	37.5%	37.5%
Operations Accounting	25.0%	25.0%	25.0%	25.0%
Customer Care	0.0%	0.0%	0.0%	0.0%
Records & Administration	0.0%	0.0%	0.0%	0.0%
Construction Maintenance	60.0%	60.0%	60.0%	60.0%
Technical Services	47.5%	47.5%	47.5%	47.5%
Maintenance Coordinator/Analyst	0.0%	0.0%	0.0%	0.0%
Engineering and Special Projects	60.0%	60.0%	42.5%	42.5%
Junior Engineer [2]	80.0%	80.0%	n/a	n/a
Regional Operations (NE)	35.0%	35.0%	35.0%	35.0%
Construction Maintenance (NE)	35.0%	35.0%	35.0%	35.0%
Engineer (NE) [2]	80.0%	80.0%	n/a	n/a
Field Staff				
Operations Accounting	25.0%	25.0%	25.0%	25.0%
Technical Services - Warehouse	50.0%	50.0%	50.0%	50.0%

[1] Position Eliminated
[2] New Position

68.1 Please provide a reconciliation of the change in estimated time on forecast capital activities with the increase in planned capital projects from 2017 to Test Year 2018.

68.2 Please explain why the Vice President (VP) of Operations & Engineering's estimated time on forecast capital activities is reduced from 80 percent to 41.5 percent for Test Year 2018, when there is significantly more capital projects planned for Test Year2018 compared to 2017.

On page 55 of the Amended Application, PNG provides the following table:

Table 27: Transfers to Capital and Overhead Capitalization

Description	$000's											
	Test Year 2019	2019 to 2018 Change		Test Year 2018	2018 to Decision 2017		Decision 2017	Actual 2017	Actual 2016	Actual 2015	Actual 2014	Actual 2013
		$	%		$	%						
Overhead Capitalization Rate [(A)/(B)]	**4.7%**	**(1.4%)**	**(23.2%)**	**6.1%**	**0.2%**	**3.5%**	**5.9%**	**4.6%**	**3.8%**	**3.7%**	**3.6%**	**4.1%**
Overhead as % of Capital Expenditures [(A)/(C)]	**19.5%**	**12.6%**	**181.7%**	**6.9%**	**(15.4%)**	**(69.0%)**	**22.3%**	**20.5%**	**15.9%**	**17.6%**	**18.0%**	**22.0%**
(A) Transfers to Capital												
Operating	506	(26)	(4.9)%	531	135	33.9%	397	379	362	314	295	302
Administrative & General	387	(219)	(36.1)%	607	(82)	(11.9)%	688	496	372	367	333	415
Total Transfers to Capital	**893**	**(245)**	**(21.5)%**	**1,138**	**53**	**4.9%**	**1,085**	**875**	**734**	**682**	**628**	**717**
(B) Expenses												
Operating	9,473	265	2.9%	9,208	172	1.9%	9,036	9,234	8,989	8,519	8,177	7,713
Maintenance	505	10	2.0%	495	8	1.6%	487	399	388	382	425	469
Administrative & General	8,158	363	4.7%	7,795	15	0.2%	7,780	8,576	9,242	8,929	8,103	8,763
Total Expenses - Net of Transfers to Capital	18,136	638	3.6%	17,498	195	1.1%	17,303	18,210	18,619	17,830	16,705	16,945
Plus: Transfers to Capital	893	(245)	(21.5)%	1,138	53	4.9%	1,085	875	734	682	628	717
Total Expenses - Gross	**19,029**	**393**	**2.1%**	**18,636**	**248**	**1.3%**	**18,389**	**19,085**	**19,353**	**18,511**	**17,333**	**17,662**
(C) Capital Expenditures (before Overhead)	**4,582**	**(11,869)**	**(72.1)%**	**16,451**	**11,593**	**238.6%**	**4,859**	**4,272**	**4,609**	**3,868**	**3,490**	**3,258**

Source: Tab Schedules, Tab 1, Pages 3 to 5

68.3 Please explain why the "% Time on Capital Activities" for Test Year 2018 should not be higher compared to Test Year 2019, considering the capital expenditures and activities planned for Test Year 2018 is significantly higher compared to Test Year 2019.

68.4 Please explain why the "Overhead Capitalization Rate" for Test Year 2018 is higher compared to Test Year 2019, when the "% Time on Capital Activities" is the same for both test years.

In response to BCUC IR 1.20.2, PNG provides the following table:

Table 20.2 - Changes in Transfers to Capital

Factors Contributing to Change in Capitalization ($'s)	Test Year 2019	Test Year 2018
(i) Change in Proportion of Capital Expenditures	(112,000)	73,000
(ii) Change in Corporate/Field Management Allocation	9,000	7,000
(iii) Change in Support Staff Allocation	15,000	(28,000)
(iv) Change in Direct Capital Labour Benefit Load	(157,000)	1,000
Increase (Decrease) in Capitalization over Prior Period	(245,000)	53,000
Change in Transfers to Capital per Table 27	(245,000)	53,000
Difference	-	-

On page 49 of the Amended Application, 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%

68.5 Please confirm, or explain otherwise, that the $112,000 decrease in capitalization in Test Year 2019 compared to Test Year 2018, caused by a change in the proportion of capital expenditures is due to more capitalized overhead being allocated to PNG(NE)-FSJ/DC Division in Test Year 2019, compared to Test Year 2018.

68.6 Please explain why there is a $157,000 decrease in capitalization in Test Year 2019 compared to Test Year 2018 caused by a change in Direct Capital Labour Benefit Load when the "% Time on Capital Activities" is the same for both test years, and there is only a small change in the employee benefit load rates in Test Year 2019 compared to Test Year 2018.

In response to BCUC IR 1.20.4, PNG states:

> As noted in response to Question 20.1, "actual" time on capital activities for the VP Operations & Engineering is not tracked. As per PNG's overhead capitalization policy, the capitalization of costs related to executive, management and field staff time are fixed at those forecast and approved for the respective test year. As noted in Section 3.4.1 of the Amended Application (page 135, lines 1-10), PNG has capitalised 80% of salary and benefits for this position for each of 2016 and 2017, consistent with the estimates for these periods.
>
> Further, as noted in response to Question 20.1.1, the estimate for 2018 and 2019 has been reduced to 41.5% based on the employee's own assessment of time to be dedicated to capital projects given knowledge of planned business activities and clarity of role to be fulfilled in this regard. However, PNG will monitor this closely, particularly given the addition of some larger capital projects to the Amended Application, including the Copper River repair and the RIPET Project.

68.7 Please discuss what PNG means by "PNG will monitor this closely, particularly given the addition of some larger capital projects to the Amended Application…." Please also discuss what implications the results of the monitoring may have on the capitalization rate in the current and future test periods.

68.8 Please discuss how PNG plans to monitor the VP Operations & Engineering's time spent on capital activities.

68.9 Please confirm, or explain otherwise, that PNG's plan to monitor the VP Operations & Engineering's activities in Test Years 2018 and 2019 means that PNG will be tracking the VP's actual time spent on capital activities for the test period.

68.9.1 If confirmed, please confirm, or explain otherwise, that in accordance with PNG's capitalization policy, the capitalization rate for the VP Operations & Engineering will remain fixed during Test Years 2018 and 2019, even if the actual time on capital activities for the test period was discovered to be different from forecasted.

F. DEPRECIATION

69.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 58-61 and Appendix D; Exhibit B-3, BCUC IR 22.1, 22.3.1, 24.1
Net Salvage - Rate Impact

In its response to BCUC IR 22.1 PNG provides the Test Year 2018 and Test Year 2019 rate impact of incorporating the negative salvage values recommended in the Depreciation Study, as "…approximately 7.7% in Test Year 2018 and a very minor decrease in rates of approximately 0.3% in Test Year 2019 compared to the rates for these test periods presented in the Amended Application."

69.1 Please explain why a rate decrease, as opposed to rate increase, would be expected in Test Year 2019.

69.2 In the event that the negative salvage values recommended in the Depreciation Study were incorporated by PNG, please discuss if there is an expected trend in the rate impact that this would have beyond 2019? For example, would rate decreases be expected to continue and would the rate decreases become more significant? Please provide a detailed explanation.

In its response to BCUC IR 22.3.1 PNG states that: "[i]n the event that Concentric's recommendation regarding negative salvage values were adopted, PNG would consider a long transition period given the significant rate impact from making this change and in given that PNG's delivery rates are the highest in the British Columbia."

In its response to BCUC IR 24.1, PNG states that: "Newfoundland and Labrador Hydro have filed a current proposal where they have included a gradual phase in of net negative salvage into their proposed depreciation rates."

69.3 Please discuss how a transition period would work from a regulatory accounting perspective, the number of years that PNG would consider appropriate and provide an illustrative example.

69.3.1 Please describe how the gradual phase-in of net negative salvage will be implemented in the Newfoundland and Labrador proposal and discuss how this differs from PNG's transition period described in the preceding IR.

In its response to BCUC IR 22.4 PNG states that: "[i]f Concentric's recommendations regarding negative salvage accounting were adopted, PNG submits that it would likely record the negative salvage accrual collected from customers in a rate base credit deferral account. Any actual costs incurred in the future for asset retirements and abandonments would then be recorded in the same deferral account."

69.4 Please provide an illustrative example of recording the actual costs incurred in the future for asset retirements and abandonments in the rate base deferral account.

69.4.1 Please confirm, or explain otherwise, that the asset retirements and abandonments would be recorded as a debit to the rate base deferral account.

69.4.2 Please explain how the asset retirements and abandonments recorded in the rate base deferral account would be amortized.

69.5 Please provide an illustrative example of the annual accounting entry that would be required for the net salvage depreciation provision.

69.6 Please discuss what is meant by the term, "Life Aspect Depreciation Provision" included in the response to BCUC IR 22.4.

The following statement is included on pages I-4 and I-5 of the Depreciation Study:

> 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.

69.7 Please discuss if the method of accounting for negative salvage described on pages I-4 and I-5 of the Depreciation Study and referenced above in the preamble is the same as the method of accounting described by PNG in its response to BCUC IR 22.4. If there are differences between the two methods, please discuss the differences and specify if the differences between the two methods results in a different revenue requirement.

70.0 **Reference: DEPRECIATION**
Exhibit B-1-1, pp. 58-61 and Appendix D; Exhibit B-3, BCUC IR 1.23.1.1
Plant Gains and Losses Deferral Account

In its response to BCUC IR 23.1.1 PNG states that it: "… believes that the plant gain losses deferral accounts for salvage values and retirement costs would no longer be required in the event that all of the net salvage values recommended in the Depreciation Study were adopted by PNG."

70.1 Please explain what the "extraordinary" and "other" categories of the plant gains and losses deferral account relate to and why these categories would still be required in the event that negative salvage accounting was adopted by PNG.

71.0 **Reference: DEPRECIATION**
Exhibit B-1-1, p. 60 and Appendix D; Exhibit B-3, BCUC IR 25.1
US GAAP

In its response to BCUC IR 25.1 PNG describes ASC 410-20-25-4 of US GAAP as it relates to negative salvage accounting.

71.1 Based on the content of ASC 410-20-25-4 provided in response to BCUC IR 1.25.1, please discuss if PNG considers negative salvage accounting for asset retirement obligations which arise from legal obligations to be in accordance with US GAAP.

71.1.1 Approximately what percentage of PNG's asset retirement obligations, arise from legal obligations?

72.0 **Reference: DEPRECIATION**
Exhibit B-1-1, Appendix D; Exhibit B-3, BCUC IR 26.1
Negative Salvage – Specific Accounts

In its response to BCUC IR 26.1 PNG states that: "the negative 10 percent is low and that negative 25 percent would be a more reasonable expectation for the equipment" in Account 418.

72.1 Please elaborate on why 25 percent is considered to be a more reasonable expectation for the equipment in Account 418 as compared to the peer comparison net salvage value of negative 10 percent.

73.0 **Reference:** **DEPRECIATION**
Exhibit B-1-1, p. 60 and Appendix D; Exhibit B-3, BCUC IR 27.2
Depreciation Rates

In its response to BCUC IR 27.2 PNG describes the Average Life Group Procedure (ALG), Equal Life Group Procedure (ELG) and Amortization Accounting. PNG states that:

> The other procedure commonly used for other Canadian and North American utility companies is the Equal Life Group (ELG) procedure. As compared to the ALG procedure, the ELG procedure is considered to more accurately estimate the actual consumption of a company's fixed assets and the most mathematically correct procedure for capital recovery.

73.1 Please provide a detailed explanation as to why the ALG procedure has been used to calculate the annual and accrued depreciation for PNG, as opposed to the ELG procedure, given that the ELG procedure is commonly used by other utility companies and, "is considered to more accurately estimate the actual consumption of a company's fixed assets and the most mathematically correct procedure for capital recovery."

74.0 **Reference:** **DEPRECIATION**
Exhibit B-1-1, pp. 59-69 and Appendix D; Exhibit B-3, BCUC IR 29.3
Land Rights

In its response to BCUC IR 29.3 PNG indicates that it "is not aware of any other Canadian gas distribution utilities that use the same methodology for Land Rights as proposed by PNG."

74.1 Please confirm, or explain otherwise, that if other Canadian gas distribution utilities don't apply the same methodology as PNG, then the normal accounting process is to amortize land rights.

G. DEFERRAL ACCOUNTS AND AMORTIZATION

75.0 **Reference:** **DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 64; Exhibit B-3, BCUC IR 30.1; PNG 2016-2017 RRA, Exhibit B-1-1, p. 95
EMAT 2018 Tool Run

In its response to BCUC IR 30.1 PNG states that US GAAP allows for expensing EMAT ILI costs as they are incurred as the costs, "which are resources required to fulfill contracts with customers, and relate to both satisfied performance obligations (i.e. gas delivered) and unsatisfied performance obligations (i.e. gas to be delivered) match at least one category of costs described above."

75.1 Please identify the categories of US GAAP ASU 2014-09, Revenue from Contracts with Customers, section 340-40-25-8 that the EMAT ILI costs match.

75.2 Please confirm, or otherwise explain that the EMAT ILI tool run costs can be capitalized as plant under US GAAP and provide the applicable US GAAP section(s) in support of the response.

In its response to BCUC IR 31.1 PNG provides a table with the annual revenue requirement impact for each of 2018-2028 of capitalization of EMAL ILI costs to a deferral account versus capitalization to plant.

75.3 Please provide the net present value (NPV) for each of the two tables provided in response to BCUC IR 1.31.1 (i.e. capitalization to deferral account and capitalization to plant).

75.4 Please provide the rate impact in each of Test Year 2018 and Test Year 2019 for each of the total revenue requirement impact of capitalization of the EMAT ILI costs to a deferral account (i.e. $41,033 in 2018 and $199,868 in 2019), and capitalization to plant (i.e. ($399,638) in 2018 and $273,792 in 2019).

On page 95 of the Amended Application (Exhibit B-1-1) in the PNG 2016-2017 RRA proceeding, PNG states that:

> An EMAT tool is a smart tool that can detect cracks in the wall of a pipe. PNG will be making use of a recently developed crack tool that is able to detect cracks in 273 mm and 323 mm pipelines. Running this new tool in the transmission pipelines will provide precise data on the location and extent of any cracks detected so their assessment and repair can be better targeted, resulting in a more effective and efficient investigative dig program. In 2017 this tool will be run for the first time through the 273mm sections of line between MP248-MP251, as well as MP256-PLS, a total distance of 15 miles.

75.5 Please confirm, or explain otherwise, that the information provided on page 95 of the Amended Application in the PNG 2016-2017 RRA proceeding is still accurate with respect to the EMAT ILI costs.

75.6 Please explain if PNG already owns the EMAT ILI tool and the costs included in the 2018 and 2019 revenue requirement, are the costs associated with operating the tool.

75.7 Please provide a breakdown of the $1.2 million in Test Year 2018 costs associated with the EMAT ILI tool runs.

75.8 Does PNG expect to incur costs related to the EMAT ILI tool runs every 7-10 years or more frequently? Please provide a detailed discussion of the frequency of these costs.

76.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, p. 65; Exhibit B-3, BCUC IR 33.1-34.3.1
Overhauled Compressor Engine Spare

In its response to BCUC IR 33.1 PNG states that:

> The machine that will be overhauled has reached the Original Equipment Manufacturers recommended hours for overhaul (25,000 hours). This machine will become the strategic spare for the fleet, but specifically R1. The other compressors are all around the recommended age of going through overhaul. None of these have been overhauled since the sites have been dormant.

76.1 Are there any compressor engine spares that have not yet reached the recommended hours for overhaul, which would allow for a delay in the overhaul of a compressor engine spare? Please discuss and include the number of hours for the compressor engine with the least number of hours, if the number of hours would allow that engine to be the strategic spare and for how long.

76.2 Please identify the categories of US GAAP ASU 2014-09, Revenue from Contracts with Customers, section 340-40-25-8, that match the overhauled compressor engine spare costs.

76.3 Please confirm, or otherwise explain that the overhauled compressor engine spare costs can be capitalized as plant under US GAAP and provide the applicable US GAAP section(s) in support of the response.

In its response to BCUC IR 1.34.3 PNG provides a table with the annual revenue requirement impact for each of 2018-2023 of capitalization of overhauled compressor engine spare costs, to a deferral account versus capitalization to plant.

76.4 Please provide the NPV for each of the two tables provided in response to BCUC IR 1.34.3 (i.e. capitalization to deferral account and capitalization to plant).

76.5 Please provide the rate impact in each of Test Year 2018 and Test Year 2019, for each of the total revenue requirement impact of capitalization of the overhauled compressor engine spare costs to a deferral account (i.e. $18,811 in 2018 and $146,276 in 2019), and capitalization to plant (i.e. ($183,204 in 2018 and 200,378 in 2019).

77.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, pp. 68-69; Exhibit B-3, BCUC 36.1-36.5
Option Fee Payment Deferral Account

In its response to BCUC IR 36.2 PNG states that the "$321,000 was reported and remitted to the CRA as part of PNG's March 2016 GST remittance."

77.1 Please explain why the $321,000 remitted to the Canada Revenue Agency (CRA) in 2016 was not included in the 2016-2017 RRA proceeding.

In its response to BCUC IR 36.5 PNG states that it, "…would consider it appropriate to apply for deferral account treatment of any future negotiated option fees as PNG is cognizant that different circumstances may require different treatments for regulatory purposes."

77.2 Please confirm, or otherwise explain, that PNG is not seeking approval in the current proceeding to record any future negotiated option fees in the option fee payment deferral account.

78.0 **Reference: DEFERRAL ACCOUNTS**
Exhibit B-1-1, pp. 70; Exhibit B-3, BCUC IR 37.1-37.6
Triton LNG Project (PLP Project) Amendment Sharing

In its response to BCUC IR 37.2 PNG states that the, "TRA dated July 2013 between PNG and Triton pertains to firm capacity on the PLP Project."

In its response to BCUC IR 37.5 PNG states that:

> …between 2013 and 2016, four PNG employees spent some time on the PLP project. In particular, there was time spend by one employee in the accounting group to track the PLP project expenditures and time spent by senior executives to negotiate the agreements with Triton. While PNG estimates the cost of this time to be approximately $160,000 there were no additional costs incurred as these activities were performed by salaried employees as part of their regular roles and responsibilities.

78.1 Does PNG consider the Transportation Reservation Agreement (TRA), and subsequent Amendment Agreement, between Triton and PNG and the PLP Project to be non-regulated activities? Please discuss why or why not.

78.2 Did PNG consider including an offsetting amount in its revenue requirement to account for the $160,000 spent by PNG employees on the PLP project? Please discuss why or why not.

78.3 Please provide an estimate of the costs included in PNG's revenue requirement of the time spent by PNG employees in each of 2016 and 2017 on all non-regulated activities.

78.3.1 Please provide a discussion of how PNG tracks and monitors employee time spent on non-regulated activities.

On page 70 of the Amended Application PNG states that it: "recognized revenues of approximately $6.8 million related to the recovery of overhead and carrying costs" upon execution of the Amendment Agreement. Further, in its response to BCUC IR 37.4 PNG states that it: "recovered approximately $14 million of development costs from Triton."

78.4 Please provide a breakdown of the development costs, overhead costs and carrying costs incurred by PNG, and the total revenues recovered from Triton related to the Transportation Reservation Agreement, Amendment Agreement and the PLP Project.

On April 9, 2018, PNG filed an application with the BCUC for approval of a Letter Agreement between PNG and Triton LNG Partnership dated March 29, 2018 (April 9, 2018 Application).

78.5 Please discuss the impact, if any, on PNG's 2018–2019 revenue requirements of the Letter Agreement between PNG and Triton LNG Partnership dated March 29, 2018.

78.6 Please provide details of the differences between the Letter Agreement between PNG and Triton LNG Partnership dated March 29, 2018, and the TRA dated July 2013 between PNG and Triton, and the subsequent Amendment Agreement that result in one being filed with the BCUC for approval but not the other.

H. RATE BASE

79.0 **Reference:** **Rate Base**
Exhibit B-3, BCUC IR 41.0
New replacement tools

In response to BCUC IR 41.1, PNG provided the following table breaking down major capital projects for 2018 and 2019:

Major Capital Projects	2018 Budgeted Cost Excluding Overhead	
Planned Recurring Costs - New Replacement Tools		
Purchase 4 Pipe Locators	$	31,127
Unspecified Tools > $1,000		30,600
Purchase 5 Gas Detectors GT40		12,954
Purchase Shelving For Meter Storage		8,670
Purchase New Spatial GPS Unit		6,120
Procure Small Tools for New Technicians		5,100
Purchase 2 Steel Squeeze Off Tools		4,437
Purchase Hetek EI-5 Ethane Dector		3,876
Replace Old Ethane Identifier		3,672
Purchase Emergency Pipe Squeezers		3,570
Purchase Druke Pressure Calibration Guage		3,366
Purchase Handheld Pressure Indicator		1,530
Replace old soil resistivity probe		1,428
New/Replacement Tools and Equipment	**$**	**116,450**

Major Capital Projects	2019 Budgeted Cost Excluding Overhead	
Planned Recurring Costs - New Replacement Tools		
Unspecified Tools > $1,000	$	31,836
Purchase Snow Blower and Snow Remover Bucket		14,888
Purchase New Flue Gas Analyser		6,365
Purchase Emergency Pipe Squeezers		6,324
Purchase 2 Gas Detectors GT40		5,508
Purchase 2 Steel Squeeze Off Tools		4,590
Purchase Mueller No-Blow vlv Changer		4,182
Purchase Druke Pressure Calibration Guage		3,570
New/Replacement Tools and Equipment	**$**	**77,263**

79.1 The budgeted cost for Unspecified Tools > $1,000 is $30,600 and $31,836 for 2018 and 2019 respectively. Please provide a detailed explanation of what constitutes 'unspecified tools' and if possible a detailed equipment breakdown of 'unspecified tools'.

79.2 Expenditures on the following items appear in the budget for 2018 and are re-purchased in 2019: Gas Detectors GT40, Steel Squeeze Off Tools, Druke Pressure Calibration Gauge. Please explain why these items appear as expenditures in both 2018 and 2019.

80.0 **Reference:** **Rate Base**
Exhibit B-1, p. 87; Exhibit B-3, BCUC IR 42
Copper River MP 250 Repair

On page 87 of the Amended Application, PNG states:

> In October 2017, PNG-West experienced a major washout on the Zymoetz (Copper) River exposing the main 273mm diameter, high pressure transmission pipeline that feeds Terrace, Kitimat and Prince Rupert. The exposed portion of the transmission line was rendered unfit for service and had to be replaced by parallel bypass lines until such time that sufficient access can be reinstated and a permanent repair can be completed.

80.1 Was flood prevention considered in the construction of the original pipeline? Please identify the flood specifications that were used when the original pipeline was designed and constructed.

80.1.1 Please discuss the probability of a similar washout of the pipeline occurring in the short term and medium term. Please identify the measures, if any that have been put in place to mitigate the impact of similar events in the future.

In its response to BCUC IR 42.5, PNG provides the following table:

Response:

The budgetary control cost estimate is as follows:

Cost Element	Control Budget
Contractor – Pipeline	$1,200,000
Contractor – Tote Road Construction	1,050,000
Contractor – Bench Road / Pipeline R/W	400,000
Contractor – FSR Repairs for Access	210,000
	2,860,000
Materials – Rip Rap	1,250,000
Materials – Pipeline	130,000
	1,380,000
Design and Permitting	480,000
Contingency	910,000
Total	$5,630,000

80.2 Please explain the decrease in the budgetary control cost estimate from $5,683,000 in the Amended Application, to $5,630,000 in PNG's response to BCUC IR 42.5.

80.3 What are PNG's policies to include and calculate project contingency?

80.4 Please explain why the construction work is being carried out by contractor labour versus regular labour.

80.4.1 How does PNG determine the need to outsource labour?

In response to BCUC IR 42.4 PNG states:

> A milestone schedule is provided below. Importantly, there is some urgency to complete the project in 2018, given the risks associated with the temporary repair and further washouts.
>
> With the permanent repair, the detailed design has commenced, from which a Class 3 cost estimate and detailed construction schedule will be developed. PNG will have better certainty on the costs once the tendering is completed in August.

The project is on track to be completed in 2018, with the following milestones:

- Jan 2018 – Commencement;
- March 2018 – Tote Road Design and Tendering;
- May 2018 – Tote Road Construction;
- June 2018 – Detailed Design Complete and Permitting Application Submitted;
- July 2018 – Request for Proposals;
- August 2018 – Contract Award;
- September 2018 – Permit Approval and Construction Commencement;
- October 2018 – Construction Complete;
- November 2018 – Site Demobilization.

As indicated in response to Question 42.1.1, both permitting and overall project delivery schedule are considerable risks to project delivery in 2018. Should the project show signs of significant schedule slip such that permitting and contract related milestones will not be met, a contingency plan will be executed to further armor the temporary bypass pipeline in order to protect against fall water levels and river velocities. This will push project completion into 2019 and result in a projected increase in armoring costs of approximately $1,000,000 to address high water levels typically experienced in the fall.

80.5 Please discuss if the Copper River project is currently on track with the milestone schedule.

80.5.1 What steps have been or are being taken to ensure project completion in line with the original milestone schedule?

80.6 Please discuss if PNG anticipates any significant schedule slips in this project?

80.7 Does PNG anticipate that the project will be delivered without delay and without the highlighted increased costs of $1,000,000? Please discuss.

80.8 When designing the milestone schedule, did PNG consider setting deadlines for permitting and contract related milestones earlier in the year to minimize construction risks (such as weather delays).

80.8.1 Has the probability of construction risks been built into the project contingency?

80.8.2 What, if any, are the financial risks associated with the project and how have they been mitigated?

80.9 Please provide clarification on the detail of the Contract Award that is due in August 2018 according to the milestone schedule.

80.10 Did PNG consider commencing construction earlier in the year to minimize construction risks? Please discuss why or why not.

80.10.1 Please identify the risks associated with the construction and if these risks have been built into the time line.

81.0 **Reference:** **Rate Base**
Exhibit B-1-1, pp. 88-89; Exhibit B-3, BCUC IR 43
Ridley Island Propane Export Terminal (RIPET) Gas Supply - Costs

In response to BCUC IR 43.4 PNG provided the following table:

	Pipeline Phase 1	Pipeline Phase 2	Station	Project Activity Subtotals
Engineering Design, Permitting	$ 272,000	$ 360,000	$ 40,000	$ 672,000
Construction	$ 1,189,500	$ 1,906,000	$ 370,000	$ 3,465,500
Project Contingency				$ 345,000
Total Installed Project Cost				$ 4,482,500
Estimate Accuracy (Class 4)	-20% to +30%			

Notes:
Pipeline Phase 1 – Constructed in Q1/Q2 2018 to avoid conflict with competing AltaGas construction
Pipeline Phase 2 – Constructed in Q3 2018 in accordance with AltaGas facility construction schedule

81.1 What, if any, are the financial risks associated with the project and how have they been mitigated?

81.2 What, if any, are the construction risks associated with this project, and how have they been mitigated?

81.3 Please provide a detailed explanation for the increase in the total installed project cost from $3,707,000 in the Amended Application, to $4,482,500 in PNG's response to BCUC IR 44.1.

81.3.1 Please provide a copy of the original budget and the current budget with an explanation for any variances for each cost category.

81.3.2 Please provide a breakdown of the total project cost between the costs for the existing pipeline amendment, the new pipeline and the new station.

82.0 **Reference:** **Rate Base**
Exhibit B-1-1, pp. 88-89; Exhibit B-3, BCUC IR 43.1
RIPET Project - Schedule

In its response to BCUC IR 1.43.1 PNG provides a list of key milestones for the RIPET project.

82.1 Please explain if PNG is still on track to complete the project in 2018, and specifically if the existing pipeline amendment is still expected to be complete in May 2018.

83.0 **Reference:** **Rate Base**
Exhibit B-1, pp. 88-89; Exhibit B-3, BCUC IRs 43-44
RIPET Project – Related Party

On page 88 of the Amended 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.

83.1 Please provide PNG's code of conduct for business transactions between PNG and AltaGas, relevant to this Application.

83.1.1 Please highlight any areas that are applicable to the RIPET Project.

83.2 Please discuss if there are any risks associated with the related party nature of the RIPET project and the measures that PNG has in place to mitigate these risks.

84.0 **Reference: Rate Base**
Exhibit B-1-1, pp. 88-89; Exhibit B-3, BCUC IR 43
RIPET Project – Technical

On page 88 of the Amended 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.

84.1 Please provide the current capacity of PNG's existing 114mm high pressure gas pipeline that is the subject of amendments related to the RIPET.

84.1.1 Please explain if the amendments to PNG's existing pipeline will increase its capacity and if so, by how much.

84.1.2 If the proposed amendments to the existing pipeline increase capacity beyond what is required to supply the RIPET, please explain why and identify any other projects that these amendments are intended to serve.

84.2 Please describe the technical details of the amendments to PNG's existing 114mm high pressure gas pipeline that is the subject of amendments related to the RIPET, and discuss why these amendments are required to serve RIPET.

84.3 Please provide the capacity of the new 114 mm high pressure gas pipeline and station. If the capacity exceeds the requirements of the RIPET, please explain why and identify any other projects that these amendments are expected to serve.

84.4 Please provide any visual materials or maps that are available with respect to the RIPET project specifications.

85.0 **Reference: Rate Base**
Exhibit B-1-1, pp. 88-89; Exhibit B-3, BCUC IR 44
RIPET Project – Rates

In its response to BCUC IR 44.1, PNG provides the high level results of the mains extension test conducted for the RIPET project.

85.1 Please provide a copy of the mains extension test performed for the capital expenditure related to the RIPET project based on the most up to date information.

In its response to BCUC IR 44.8, PNG provides the expected annual revenue requirement impact of the RIPET project.

85.2 With respect to the revenue requirement impact analysis provided, please also provide the corresponding annual rate impact of the RIPET project.

85.2.1 Please confirm, or otherwise explain, that the revenue requirement analysis includes all operating costs associated with proving service to RIPET.

85.2.2 Please confirm the depreciation rate(s) that is applicable to the RIPET project assets.

85.2.3 Does the revenue requirement analysis include an estimate of annual maintenance costs associated with the pipeline? If not, please discuss why not.

85.3 Please confirm what the undepreciated balance of the RIPET project assets will be at the end of the term of the TSA agreement.

85.3.1 If the asset is no longer used and useful at the end of the TSA term, what is the proposed regulatory accounting treatment, and resulting rate impact, for the undepreciated balance of the North Pine Fuel Gas Pipeline? Please include supporting calculations in the response.

86.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, BCUC IR 46.5, Attachment 1.46a
Geographic Information System (GIS) – Justification and Need

In its response to BCUC IR 46.5, PNG provides details of the need for the GIS Project and states that "[i]mplementing GIS technology provides PNG with opportunities for streamlining and standardizing business processes to improve process efficiency and consistency between geographic locations, integrate with key business systems, improve communication and streamline workflows within PNG."

Section 2 of Attachment 1.46a includes information on the GIS project justification.

86.1 Please elaborate on how the GIS Project will:

a) streamline and standardize business processes;
b) improve efficiency and consistency between geographic locations;
c) integrate with key business systems;
d) improve communication; and
e) streamline workflows.

Please provide specific examples for each of the preceding categories.

86.1.1 For each of the above-noted items, please quantify the annual financial benefit, where possible.

86.1.2 For each of the above-noted items, please identify and describe any corresponding reduction in FTEs and labour costs. Please also identify the account(s) and test year(s) these benefits will impact.

87.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, Attachment 1.46a and 1.46b
Geographic Information System - Benefits

Page 8 of the GIS Business Case identifies the following three major categories of benefits of implementing an enterprise GIS: (i) risk reduction; (ii) regulatory compliance; and (iii) simplified business and work processes. Further, on page 12 of the GIS Business Case PNG states that it, "wishes to achieve the benefits from the GIS implementation as soon as is practical, and there is a sense of urgency to improve the current processes, tools and data." Further on page 6 PNG states that the:

> … primary motivating factors for moving forward with the PNGISI Project are (1) to develop an authoritative system of record for PNG's asset data; (2) to provide an enterprise-wide system to allow PNG staff (particularly field staff) to operate much more efficiently and consistently; (3) to improve integration between key business systems; (4) to improve capabilities and capacity for reporting and regulatory compliance (i.e. CSA standards, BC Oil and Gas Commission and Technical Safety BC regulations); and (5) to incorporate industry best practices and technology into PNG's operations.

Page 18 of Attachment 1.46b includes a list of the potential benefits of the GIS Project. Further on page 19 of Attachment 1.46b PNG states that:

> The primary motivating factors for moving forward with the GIS implementation from PNG Management's perspective are to embrace contemporary industry best practices and technology, develop an authoritative System of Record with regards to PNG's assets, and provide a system which will allow PNG staff (particularly field staff) to operate much more efficiently and consistently than what can be achieved with the current tools and processes.

Page 4 of Attachment 1.46a states that, "GIS is a mainstream technology implemented across the North American utility sector due to its recognized strategic and economic value in organizations."

In its response to BCUC IR 46.2 PNG states that:

> The lack of a GIS system is putting PNG at risk of being out of compliance with codes, standards, and regulations. PNG's delay in adopting GIS technology is increasing its exposure to risks related to the safe and reliable delivery of natural gas to its customers.

87.1 Please describe and quantify the economic value of the proposed GIS Project for PNG.

87.2 Please provide details and specific examples of the risk reduction associated with the proposed GIS project as it relates to system integrity, emergency management, and safe and reliable service. Please also discuss any financial benefits associated with the risk reduction for PNG and quantify, where possible.

87.3 For any other benefits of the proposed GIS project that have not been quantified in the preceding IRs, please identify and describe the benefit and quantify, where possible.

87.4 Please provide an expected forecast of the benefit to cost ratio of the GIS project for PNG.

87.5 Please discuss if there are any other specific benefits for ratepayers of the GIS project.

87.6 Please discuss if there are any risks associated with the proposed GIS project.

88.0 **Reference:** **RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, BCUC IR 46.2;
Attachment 1.46a, pp. 8-10 and Attachment 1.46b pp. 56-64
Geographic Information System - Alternatives

In its response to BCUC IR 46.2 PNG states that:

> The comparison of the alternatives considered was completed in the context of alternatives in GIS configurations and implementation. In the third quarter of 2017, PNG engaged Spatial Vision Group Inc. (SVG) – an engineering/geomatics consultant – to complete an in-depth evaluation of alternative GIS platforms, along with alternative implementations of the preferred technology.
>
> A review of potential vendor solutions was conducted by SVG to identify commercially available GIS oriented technology, product and services offerings that may be a good fit with PNG's requirements. The scope of this review was constrained to include only those solutions that were considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector. An initial assessment of potential candidates was conducted to arrive at a short list of candidates subject to a more thorough assessment that concluded that Esri's ArcGIS platform is currently the de-facto standard for GIS in the utilities sector; industry trends indicate the Esri will continue to occupy this position in the marketplace for the foreseeable future.

SVG considered the following four alternatives for implementation of PNG's GIS:

1. Greenfield – PNG, using internal resources, implements its GIS from the ground up;
2. AUI Leveraged – PNG teams with AUI to leverage its experience and expertise to implement its GIS;
3. ENSTAR Leveraged – PNG teams with ENSTAR to leverage its experience and expertise to implement its GIS;
4. Outsource – PNG uses a team of contractors to develop and deliver a turn-key GIS.

After comprehensive and informative discussions with both AUI and ENSTAR, it quickly became apparent that the Greenfield option was not a competitive alternative to one that would benefit from the expertise of both AUI and ENSTAR. In addition, the Greenfield option was not consistent with the strategic direction set out for IT implementations at AltaGas' Canadian Utilities. Accordingly, the Greenfield option was dropped from the list of alternatives considered in the detailed evaluation.

The alternatives are also discussed on pages 9-10 of the GIS Business Case, with an assessment of candidate GIS solution vendors outlined on Table 3. Further, pages 56–64 includes a detailed assessment of the alternatives.

88.1 Please explain how the information contained in Table 3 of the GIS Business Case, specifically the information related to the vendor Esri ArcGIS, is related to the four alternatives for implementation that are included in response to BCUR IR 46.2 and on page 10 of the GIS Business Case.

88.2 Please explain if there are any other gas distribution companies in Canada outside of the AltaGas group of companies that use Esri's ArcGIS platform for GIS.

88.3 Please clarify if the vendor/product list in Table 3 of Attachment 1.46a and Table 6 of Attachment 1.46b relates to the initial assessment of potential candidates, or the short list of candidates subject to a more thorough assessment.

88.3.1 If the above-noted tables relate to the short list, please provide a list of all GIS vendors that are considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector and identify those that were considered as part of the PNG GIS Project. For those that were considered, please discuss why they ultimately were not considered an appropriate alternative to short list and for those not considered, please explain why not.

88.3.2 If the above-noted tables do not relate to the short list, please confirm that the three vendors are the only GIS vendors that are considered leaders based on industry trends and/or had significant market share in the utilities (and particularly natural gas distribution) sector.

On page 12 of the GIS Business Case, PNG states that the, "budget assessment compares the expected costs of each of the GIS implementation alternatives." Table 5 on page 13 of the GIS Business Case includes a summary table of the alternatives rankings, including quality component scores, schedule component scores and budget component scores.

Further, pages 56 to 61 of Attachment 1.46b includes a detailed analysis of the alternatives and identifies the following alternatives that were considered: 1. AUI, ENSTAR and Outsource.

88.4 Please provide the results of the project cost estimates for each of the four alternatives that were developed in determining the budget component score in Table 5 of the GIS Business Case.

88.5 Please provide a detailed discussion as to whether PNG considered maintaining the status quo, rather than proceeding with the proposed GIS project and ultimately why this was not considered to be an appropriate alternative.

88.5.1 Please provide a comparison of expected cost benefits and expected cost risks of maintaining the status quo versus GIS implementation.

89.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, Attachment 1.46b p. 33
Geographic Information System – Peer Interviews

On page 33 of Attachment 1.46b PNG states that SVG held meetings with "two similar gas transmission and distribution utilities, AltaGas Utilities Inc. and ENSTAR (both are subsidiaries of AltaGas Limited).

89.1 Please discuss if PNG and/or SVG considered expanding the scope of the peer review beyond subsidiaries of AltaGas Limited and why or why not.

89.2 Please provide any available information on the permeation of GIS technology in other gas distribution utilities in Canada and specifically in BC, other than companies in the AltaGas Limited group.

90.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, BCUC IR 46.1 and Attachment 1.46a, Appendix A5
Geographic Information System – Project Schedule

Appendix A5 of the GIS Business Case includes the implementation schedule and milestones.

In its response to BCUC IR 46.1 PNG states that:

> PNG is currently defining the organization and planning the implementation of this project. At this time, PNG has identified the major tasks and timeline for the first phase of the project (Phase One) that will implement a useful GIS having a subset of the ultimate data and functionality that will be delivered over the three-year span of the overall project. Included is a task to identify, acquire and migrate spatial data related to the scope of work that will be defined for Phase One. PNG anticipates undertaking a competitive bid process for this part of the project.

90.1 Please confirm or otherwise explain if the organization and planning phase of the project is now complete.

90.2 Please explain any expected delays to the project schedule that have been identified at present.

91.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, BCUC IRs 1.9.1.1, 1.9.1.2 46;
Attachment 1.46a, p. 3
Geographic Information System - Costs

In its response to BCUC IR 46.1 PNG states that:

> PNG is currently defining the organization and planning the implementation of this project. At this time, PNG has identified the major tasks and timeline for the first phase of the project (Phase One) that will implement a useful GIS having a subset of the ultimate data and functionality that will be delivered over the three-year span of the overall project. Included is a task to identify, acquire and migrate spatial data related to the scope of work that will be defined for Phase One. PNG anticipates undertaking a competitive bid process for this part of the project.

On page 3 of the Attachment 1.46a (GIS Business Case), PNG states that the scope of the GIS project includes, "establishing the resources to provide ongoing maintenance and support."

On page 8 of the GIS Business Case PNG states that:

> PNG adopts AUI's established GIS as the platform for its own implementation. PNG's GIS server applications will be hosted on servers located in AUI's offices, and maintained by AUI. PNG's GIS implementation will be completely aligned with the configuration in place at AUI. This will allow PNG to adopt existing applications and reports that AUI has developed, and to benefit from configuration-specific expertise at AUI for the support of PNG's GIS services and applications.

In its response to BCUC IR 46.7 and in Table 1 of Attachment 1.46a, PNG provides a cost estimate for the GIS Project. Further, its response to BCUC IR 46.6 PNG states that "PNG has defined the organization and is currently developing a more detailed implementation plan for this project. This work is being completed by PNG's project manager, who is an employee of PNG, with the support of a GIS consultant, PNG's Engineering/Drafting group, and AUI's GIS Department."

On page 14 of the GIS Business Case PNG states that subsequent phases will be defined during the completion of Phase One.

91.1 Please expand the table provided in response to BCUC IR 46.7 to categorize the component costs by operating, maintenance, administrative and capital costs, and by BCUC account for each of 2018, 2019 and 2020. Please ensure that the total costs for each year agrees to the totals in the table provided in response to BCUC IR 46.7.

91.1.1 Please discuss if any of the costs identified in the preceding IR are considered project management costs or pre-feasibility study costs.

91.1.2 Please discuss if the costs for the GIS Project are recorded in each of PNG(NE)'s divisions directly or allocated via shared services for each test year.

91.2 Please provide a breakdown by year of the project costs associated with internal labour, third party consultant costs and other resources (i.e. SVG, Esri Canada).

In response to BCUC IR 1.9.1.1, PNG states that the GIS costs forecast in operating expenses (Account 685 – General Operations) is $125,000 for Test Year 2018.

In response to BCUC IR 1.9.1.2, PNG states:

> For the asset records modernization, digital data mapping and GIS projects, these are annually phased capital projects with improvements realized throughout the years as each one of PNG's assets is digitally captured and effectively "capitalized". Subsequent to the data being captured, its use, modification, and maintenance are considered to be an operating and maintenance activity rather than capital. The costs in Account 685 relate to the operating activities for data use, modification, and maintenance.

91.3 Please provide a summary of costs that have been incurred prior to Test Year 2018 related to the GIS Project broken down by cost category (i.e. operating, maintenance, administrative and capital) and year.

91.4 Please identify the operating expenses that are ongoing or recurring costs related to the GIS Project for Test Years 2018 and 2019.

91.5 Please identify any amounts in Test Years 2018 and 2019 being transferred from operating and administrative expenses, to capital in relation to the GIS, and explain the rationale for this treatment.

91.6 Please discuss if PNG is currently on budget with the GIS Project. If there is a revised cost estimate, please provide this including a breakdown of the costs using the same categories as IR 91.3.

91.7 Given that phases subsequent to phase one will be defined during the completion of phase one, please discuss the probability that the project cost estimate will change.

92.0 **Reference: RATE BASE**
Exhibit B-1-1, pp. 89-90; Exhibit B-3, BCUC IR 46.4;
Attachment 1.46a, p. 13 and Attachment 3
Geographic Information System – Revenue Requirements and Rates

In its response to BCUC IR 46.4 PNG states that it, "has also provided a detailed cost estimate for the implementation, along with a forecast impact on customer rates, and details of its project governance and implementation plans." Further, on page 13 of the GIS Business Case PNG states:

> An analysis of the impact on the revenue requirement, and customer rates, was completed. The analysis was carried out at current regulatory rates of return, a depreciation rate of 10 percent, using a discount rate set to the nominal after tax weighted average cost of capital, and an inflation rate of 2%. The project impact on the revenue requirement was determined over 13 years, consisting of the three year implementation and 10 year post-implementation period. The initial capital costs, net present value ("NPV") of the impact to the revenue requirement and the one time equivalent rate impact is summarized in Table 6, below. The complete analysis for each of PNG-West, PNG(NE) FSJ/DC and PNG(NE) TR is provided in Appendix A3.

92.1 Please provide a working excel model with the NPV Analysis provided in Appendix A3.

92.2 Please provide a justification for the selected 10 percent depreciation rates for the GIS project capital costs.

92.3 Please justify the 13 year term selected for the NPV analysis, specifically the 10 year post-implementation period.

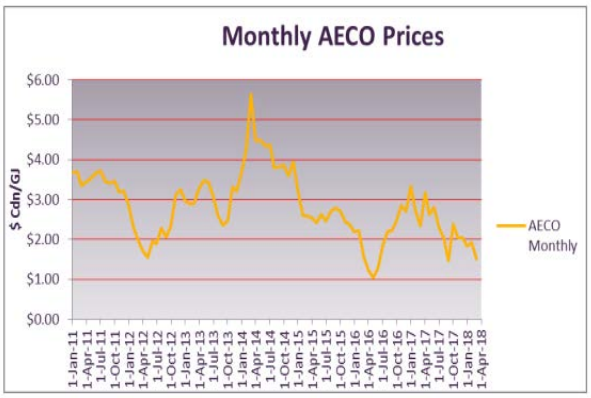
92.4 The NPV Analysis includes a line item for "AUI Support" under operating costs. Please elaborate on the support that will be provided in relation to these costs and explain why this isn't provided as part of the services already recovered through the inter-affiliate charge.

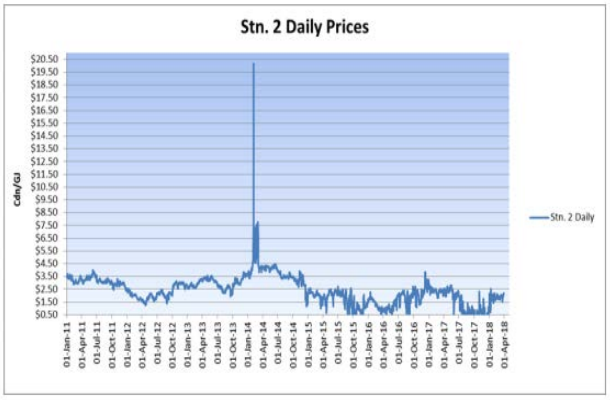
92.5 The NPV Analysis included in Appendix A3 does not include any operating cost reductions related to the GIS Project. Please discuss if there are any expected reductions in operating and maintenance costs or any other quantifiable financial benefits associated with the GIS Project that should be included in the NPV analysis. If so, please quantify by category and provide a revised NPV analysis.

I. CAPITAL STRUCTURE AND RETURN ON CAPITAL

93.0 **Reference: BUSINESS RISK ASSESSMENT**
Exhibit B-3, BCUC IR No. 1 51.2.1; Exhibit B-1-1, Appendix G
Business Risk Assessment – Market price volatility

In response to BCUC IR No. 1 51.2.1 regarding PNG's assertion that, "market prices have shown less volatility in recent years." PNG provided graphs showing the Monthly AECO prices and Station 2 daily prices since 2011.





93.1 PNG show the raw data of AECO monthly and Station 2 daily prices as noted above. Please provide further analysis to support PNG's assertion that, "market prices have shown less volatility in recent years." For example, did PNG compare any standard deviations, minimum/maximum range, or relied on any volatility index for natural gas prices?

93.2 Please discuss the impact of PNG's cost portfolio resulting from the spikes in AECO and Station 2 market prices around January 2014, and confirm that PNG's annual contracting plan has mechanisms in place to mitigate such market events.

J. IDENTIFIED SERVICE QUALITY METRICS

94.0 **Reference: Identified Service Quality Metrics**
Exhibit B-1-1, 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)

94.1 Please explain why the number of underground leaks, have increased by 12 or 80 percent in 2017 compared to 2016. Please also discuss what steps PNG is taking to address the increase in underground leaks, if applicable.

94.2 Please explain why the lost-time injury frequency rate has doubled since 2015. Please also discuss what steps PNG is taking to address the increase in the lost-time injury frequency rate, if applicable.

K. OTHER MATTERS TO BE ADDRESSED FROM PRIOR YEAR DECISIONS

95.0 **Reference: Other Matters to be Addressed from Prior Year Decisions**
Exhibit B-1-1 Section 2.1, pp. 25-28; Exhibit B-1-1,Appendix B, pp. 5-6;
Exhibit B-3, BCUC IR 55.2 -55.12
Unaccounted for Gas - Unbilled Days of Service Estimates

In BCUC IR 55.2 PNG states:

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

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

Where:

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

95.1 What criteria does PNG use to obtain a representative of a customer's daily average consumption? Does the per customer average daily gas consumption include consumption from a basket including both core and transportation customer? Please discuss.

95.1.1 Over what period is customer consumption averaged and why? Please explain.

95.2 Please discuss how PNG utilizes temperature correction factors to determine the volume of gas delivered.

95.3 Please discuss how PNG uses pressure adjustment factors to determine the volume of gas delivered.

In BCUC IR 55.5 PNG states: "PNG tracks unbilled DOS which are the number of days between the last date on which a customer's meter is read, and the end of the current calendar month. With the exception of a handful of larger customers, meters are read, and customers are subsequently billed, on a bi-monthly basis. Those customers whose meters have been read on a day during the current calendar month are referred to as "OnCycle" customers, and the unbilled DOS as OnCycle unbilled DOS. Customers whose meters are not read during the current calendar month are referred to as "OffCycle" customers."

In BCUC IR 55.12, PNG states: "PNG has a number of processes in place to ensure that customers' meter readings have been accurately recorded and applied to the billing process. All gas meters used for billing customers are subject to inspection and verification procedures specified and reviewed by Measurement Canada."

PNG further provides the following tables:

TERM1 February Adjustment (Accrual for unbilled of OnCycle customers in current month):

Estimated reduction in OnCycle Customers due to reclassification of Offcycle Budget Customers =	A	(2,935)
Estimated average unbilled DOS of Offcycle Budget Customers =	B	58.50
Reduction in OnCycle unbilled DOS =	C = A x B	(171,690)
Reduction in OnCycle Unbilled Accrual (GJ) =	D = C x 0.209 GJ per mo[1]	(35,961)

TERM2 February Adjustment (Accrual for unbilled of OffCycle customers in current month):

Estimated increase in OffCycle Customers =	E = A	2,935
Estimated average unbilled DOS of Offcycle Budget Customers during February =	F	29
Increase in OffCycle DOS in February =	G = E x F	85,108
Increase in OffCycle Unbilled Accrual (GJ) =	H = G x 0.223 GJ per mo[2]	18,971

95.4 How does PNG calculate gas consumption and subsequently bill non-residential customers? Please explain.

95.5 How many large customers does PNG supply where the meter reading and billing is not performed on a bi-monthly basis?

95.5.1 How does PNG carry out meter reading and billing for these customers, and how frequently is this process carried out? Please explain.

95.5.2 Please provide the gas volume associated with these customers for the period January 2016 to December 2017.

95.6 What is meant by 'gas meters used for billing customers'? Are these meters only used for a certain subset of PNG's customers? Please explain.

95.6.1 Do gas meters for these customers differ from those customers where the meter is read, and subsequently billed on a bi-monthly basis? How does PNG ensure accurate meter reading for these customers? Please elaborate.

95.6.2 Are these meters subject to inspection and verification procedures specified and reviewed by Measurement Canada? Please discuss.

95.7 What was the rationale for PNG implementing the change to the way unbilled days of service (DOS) were reported in February 2016? Please explain.

95.8 Please confirm, or otherwise explain, that the UAF volume adjustment made by implementing changes in February 2016 were exclusively as a result of customer reclassification.

95.8.1 Please explain why 2,935 customers were reclassified from OnCycle to OffCycle customers in February 2016.

95.8.2 Was this reclassification isolated to February 2016? If so, why was this the only occurrence of reclassification? If not, please provide detail of other instances when PNG has reclassified customers.

95.8.3 Does the tariff with PNG allow reclassification of customers without consent or notification? Please explain.

96.0 **Reference: Other Matters to be Addressed from Prior Year Decisions**
Exhibit B-1-1, Appendix B, pp. 3-9; Exhibit B-3, BCUC IR 55.2 -55.12
Unaccounted for Gas

In BCUC IR 55.3 PNG states: "The UAF volume is determined by subtracting the sum of all metered and unbilled consumption, changes in line pack, and estimates of known gas losses over a calendar month, from metered deliveries over the same period that are received onto the PNG-West system at Summit Lake."

96.1 Please confirm, or otherwise explain that changes in line pack relates to the T-South heating value changing from 39.0 MJ per m^3 to 40.0 MJ per m^3.

96.2 How does PNG estimate volumes of known gas losses over a calendar month? What are the main causes of known gas losses? Please discuss.

96.2.1 Please provide monthly volume estimates of known gas losses, attributing losses to those causes identified in response to IR 96.2 above, for the period January 2016 to December 2017.

96.2.2 Please provide the PNG-West GCVA, showing the monthly closing balance and the actual gigajoule amounts and costs/recoveries recorded in the GCVA for the previous calendar year with separate line entries for commodity purchases and sales, Company Use quantities, UAF losses and gains up to the percentage approved in the 2016 RRA decision, and the UAF gains and losses over the percentage approved in the 2016 RRA decision.

On February 24, 2017, PNG filed an application for approval of the 2016 UAF Loss above 1.0 percent (2016-UAF Loss). PNG states: "PNG further notes that large monthly UAF volumes were also recorded in the northeast on the PNG(NE) Fort St. John and Dawson Creek systems during December 2016. These results suggest that a cause may be found in the processes and reports common to all three systems…Depending on its findings, PNG may initiate a field review of its measurement facilities at its large customer sites and at Spectra's custody transfer meter facilities delivering gas onto the PNG-West, Fort St. John and Dawson Creek systems. The focus of this review would be to verify the appropriateness and correctness of the field equipment, equipment configurations and volume calculations."

96.3 Did PNG perform a field review of its measurement facilities at its large customer sites, as indicated in its February 24, 2017, 2016-UAF Loss Application? If yes, please provide this analysis. If not, why was this review not performed?

96.3.1 Please provide a breakdown of the costs associated with performing a field review of PNG's measurement facilitates.

96.4 Were any changes made to field equipment that could impact measurement of gas volumes? Please explain.

96.5 Please provide examples of issues that can arise with field equipment and configurations that could impact measurement of gas volumes, and measurement of UAF.

On page 3 of Appendix B, PNG states: "As a result of nearly 130,000 gigajoules of UAF losses during February and March of 2016, the running 12-month total UAF exceeded its historical range, increasing to 2.5 percent of deliveries over the same period, up from a running 12-month total of 0.5 percent as of January 2016. No significant reversal of these losses occurred over the following months with the result that the running 12-month total UAF remained in excess of historical bounds. Then, in December 2016, PNG recorded another, significant UAF monthly loss of approximately 60,000 gigajoules which resulted in an accumulated loss over the 2016 calendar year of 5.2 percent of deliveries. While abnormally large UAF gains or losses in each month are examined for their cause, often times such deviations are reversed over the next two months."

In BCUC IR 55.10, PNG states: "PNG then examined the daily temperatures experienced in its PNG-West service area during December and determined that average daily temperatures recorded by Environment Canada from December 11 to December 17, 2016 dropped below those expected to occur once in 50 years."

96.6 Please explain why PNG did not experience a significant reversal of the large UAF losses observed in February, March and December 2016. Please provide a detailed explanation for each period that experienced large UAF losses with reference to the stated reason for the UAF loss (i.e. change in reporting, cold snap).

96.7 Please explain why PNG first attributed the large December 2016 UAF volumes, to processes and reports common to all three systems instead of a cold weather event. What analysis did PNG undertake to ensure a cold weather event was the most likely cause of large UAF volumes?

96.7.1 How can PNG ensure UAF losses observed in its PNG-West, Fort St. John and Dawson Creek systems are not attributed to processes or common reports? Please discuss.

96.8 Please explain how the cold temperatures experienced in the PNG-West service area during December 2016 could explain the large UAF losses recorded on the PNG(NE) Fort St. John and Dawson Creek systems.

On page 9 of Appendix B, PNG states: "The total 2016 UAF loss amounts to $436,566 before tax (i.e. 226,552 GJs times $1.927/GJ, which is the approved Company use gas commodity cost applied throughout 2016). The difference between the 1.0 percent UAF not requiring further Commission approval and the 5.2 percent actual UAF is 183,336 GJs which amounts to $353,288 before tax (i.e. 183,336 GJs times $1.927/GJ)."

96.9 Please confirm, or otherwise explain, that the Company Use Rider rate effective January 1, 2018, includes the value of UAF losses over the 1.0 percent ($353,288).

96.9.1 Please provide the amount of the company use rate rider per GJ that relates to the 2016 UAF losses over 1 percent.

96.10 Please confirm the time period over which the 2016 UAF value above 1.0 percent is amortized.