PNG & TRITON LNG LETTER AGREEMENT
EXHIBIT B-2

Pacific Northern Gas Ltd.
2550 - 1066 West Hastings Street
Vancouver, BC V6E 3X2
Tel: (604) 691-5680
Fax: (604) 697-6210
Email: jkennedy@png.ca

Janet P. Kennedy
Vice President, Regulatory Affairs & Gas Supply

Via Web Upload and Courier

June 1, 2018

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

File No.: 4.2.7 (2018)

Attention: Patrick Wruck
Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

Re: Pacific Northern Gas Ltd.
Application for Approval of Letter Agreement between
Pacific Northern Gas Ltd. and Triton LNG Limited Partnership
Responses to BCUC Information Request No. 1

Accompanying, please find Pacific Northern Gas Ltd.'s responses to the referenced information requests uploaded to the Commission's website earlier today.

Ten printed copies of the responses will be distributed to the Commission's office by courier. Printed copies will be provided to other parties upon request only.

Please direct any questions regarding the application to my attention.

Yours truly,

Janet Kennedy

J.P. Kennedy

Pacific Northern Gas Ltd.
Pacific Northern Gas Ltd. and Triton LNG Limited Partnership
Letter Agreement Application

INFORMATION REQUEST NO. 1 TO PNG

1.0 Reference: INITIAL CAPACITY
Exhibit B-1, Application, pp. 2–3, 5
Firm service volume – initial capacity

Pacific Northern Gas Ltd. (PNG) states on page 2 of the Application that "representatives of AltaGas formally approached PNG in July 2017 requesting information about the status of PNG's unutilized capacity with the intention of securing an option to contract all available capacity to Ridley Island, British Columbia."

PNG further states that it "advised AltaGas that it could provide approximately 20 MMcf/day of gas to Ridley Island using its existing mainline transmission assets."

PNG states on page 3 of the Application that it has agreed to provide Triton LNG Limited Partnership (Triton) with at least 20 MMcf/day of firm gas transportation service capacity (Initial Capacity), and that this represents the maximum capacity currently available to Ridley Island using existing facilities and "minimum additional capital investment" to supply this committed firm capacity.

1.1 Please explain if PNG has incurred any costs (capital or operating) to determine the amount of maximum available capacity (i.e. 20 MMcf/day) it is able to provide to Triton.

Response:

For the 20 MMcf/day case, PNG has utilized its hydraulic models, past operating history, and a preliminary assessment of the capital and O&M expenditures required. Unrelated to Triton, PNG notes that it had previously conducted some preliminary work in 2017 to review the capital and O&M required to re-activate part of the PNG West transmission system for different contract demand amounts to select locations, including the capacity to the Prince Rupert area. PNG utilized a third-party engineering consultant to support this work in 2017. As a prudent operator, PNG believes it is necessary to maintain an operating knowledge of its system and an awareness of the scope and costs to reactivate its system for prospective industrial customers. PNG notes that finding customers to contract for the unutilized capacity available on PNG West's transmission line has been one of its key objectives in the past years.

1.1.1 If yes, please provide a breakdown and description of these costs and explain how PNG intends to recover these costs.

Response:

PNG incurred approximately $32,000 to develop the scope and update the re-activation costs for a potential major customer in the Prince Rupert area. The entire amount was incurred for costs related to a third-party engineering consultant. These costs were included in PNG's 2017 operating expenses.

1.2 Please provide a breakdown of the capital and operating and maintenance (O&M) costs required to supply the 20 MMcf/day of committed firm capacity to Triton.

Response:

Recommissioning PNG West System - to Deliver 20 MMcf/day to Prince Rupert Region

The initial capital costs as estimated to the AACE Class III accuracy range (-15% / +20%) are expected to be $5.9 million before AFUDC (and not including the interconnecting pipeline work, see discussion that follows). The work involves pipeline integrity and compression upgrades to re-activate the existing PNG transmission system to its fully licenced maximum operating pressure (MOP).

Capital Cost Item – Prince Rupert Region (not including interconnecting pipeline)	**Amount** ($ million)
Procurement	0.8
Engineering	0.4
PNG Overhead	0.4
Non-Construction Sub-total	**1.6**
Compression Upgrades	1.8
Integrity Digs and Repairs	1.5
Stopples Installation	0.3
Construction Sub-total	**3.6**
Contingency	0.7
AFUDC	XXX
Total	**5.9**

Capital compression upgrades at the R1 compressor station are required in order to run the compressor on a full time basis (versus current pulse operation) and at higher discharge pressures and volumetric flows. This work includes sending Unit #3 and the spare compressor for rebuild, servicing of turbines, restaging Unit #3 compressor, replacement of various compressor, turbine and instrumentation equipment, and installation of stopple equipment.

The capital pipeline integrity work involves digs and repairs needed in order to restore the system from the recent nominal operation to higher pressures. PNG has identified sites upstream of Thornhill (on mainline) and downstream of Thornhill towards Ridley Island on the NPS 8 line that require repair in order to reinstate operation at fully licenced MOP.

Additional capital expenditures include increased maintenance capital required at the R1 compressor station, including more frequent overhauls (every 3 years vs. every 9 years at present), and additional funds necessary for small components in case of breakdown.

Maintenance Capital Cost Item	Amount
Small components in case of breakdown	$30,000 per year
Overhaul Costs	$600,000 every 3 years

The ongoing incremental operating costs are displayed below:

Operating Cost Item	Amount ($ 000)
Additional costs for gas control monitoring	18
Additional monthly inspections	30
Additional Odorant	45
Small repairs and consumables	25
0.5 FTE	75
Total	**193**

Interconnecting Pipeline to Project Site

To deliver the full 20 MMcf/day to the delivery point on Ridley Island, PNG would also need to perform pipeline work involving design and construction of an approximately 13 kilometre NPS 8 or greater pipeline from PNG's existing Galloway Station to the assumed Ridley Island facility site as replacement of the existing NPS 4 pipeline currently servicing Ridley Island given that the NPS 4 pipeline is hydraulically limited to ~ 4-5 MMcf/day. Work would include design and construction of a high pressure metering station, with the assumption that service would be taken at line pressure and would not require pressure regulation. This aspect is not included in the cost estimate at this time, and will be developed as part of the preliminary engineering work.

PNG notes that the negotiated unit contract demand does not include the toll for the Interconnecting Pipeline. PNG would file a separate application to the BCUC with regard to the construction of the Interconnecting Pipeline and the proposed new tariff for service on this pipeline. PNG reiterates that this matter is not addressed in the current Application.

1.2.1 As part of the above response, please distinguish between the O&M and capital costs (including the "minimum additional capital investment" referred to by PNG in the above preamble) required in order to begin providing the firm service to Triton, and the future ongoing capital and O&M costs required to provide this service.

Response:

Please see the response to Question 1.1.2.

1.2.2 Please explain how PNG proposes to recover the costs incurred to supply the Initial Capacity, including the "minimum additional capital investment," and explain why this proposed recovery method is appropriate.

Response:

The proposed unit demand charge is sufficient to recover the costs to be incurred to supply the Initial Capacity, including the "minimum additional capital investment" as well as incremental margin that would reduce existing customer rates. Please also see the response to BCUC Confidential IR No. 1.1.1.

1.3 Please explain how PNG determined it had a maximum available capacity of 20 MMcf/day.

Response:

The 20 MMcf/day volumetric flow requires no specific pipeline expansion on the western mainline, only re-activation costs. This determination was arrived at through hydraulic modelling of the PNG West system and engineering reviews. As described in response to Question 1.2, the work involves upgrades to the R1 compressor station, additional pipeline dig and integrity work to facilitate increased system pressure. PNG has an existing NPS 8 pipeline between Terrace and the Prince Rupert area which has a maximum capacity of 27 MMcf/day before additional compressor upgrades or looping is required.

1.4 Please discuss the likelihood that less capacity than the anticipated 20 MMcf/day will be available to supply to Triton.

Response:

PNG believes there is a high likelihood that the capacity would be available up to 20 MMcf/day. In PNG's agreement with Triton, PNG has effectively reserved this capacity for Triton under the terms of the agreement. If Triton advances its project, then there is a low likelihood Triton would proceed with contracting for less than 20 MMcf/day. PNG understands there are benefits from economies of scale for such industrial projects. At this time, there have not been discussions regarding contracting for less than 20 MMcf/day.

1.5 In the event that the capacity demand exceeds the maximum available capacity, what impact would this have on Triton and on other existing customers? Please specifically explain how PNG would address a situation where a capacity issue occurs.

Response:

PNG submits that it would not contract for additional firm capacity that is not available to be offered and therefore, PNG cannot foresee a situation whereby the capacity demand exceeds the maximum available capacity. However, should that situation arise, PNG would curtail and restrict the delivery of gas to customers in accordance with prevailing contractual terms and PNG's General Terms and Conditions.

1.6 Please explain how PNG would address a situation where a new customer requested firm capacity service during the time period that PNG is providing the remaining available 20 MMcf/day of capacity service to Triton. Please explain the impact of this scenario on the potential new customer, on Triton and on existing customers.

Response:

PNG would not contractually offer firm capacity if this capacity was not available. Depending on the requested firm capacity service required, PNG would make best efforts to provide this if the capacity was available. As shown in the table provided in response to Question 1.7, PNG has additional firm capacity available even after providing Triton with 20 MMcf/day.

However, should a new customer require more capacity than is available on PNG's system at that time, PNG would review alternatives and prepare a proposal to provide service which may or may not require a contribution from the new customer. In this scenario, PNG expects that there would be no impact on Triton as their toll would be contractually fixed. For the potential new customer, either an existing rate or a new rate would be proposed, depending on the results of PNG's analysis. PNG would also ensure that existing customers continue to remain whole or receive some benefit in the form of future rate reductions.

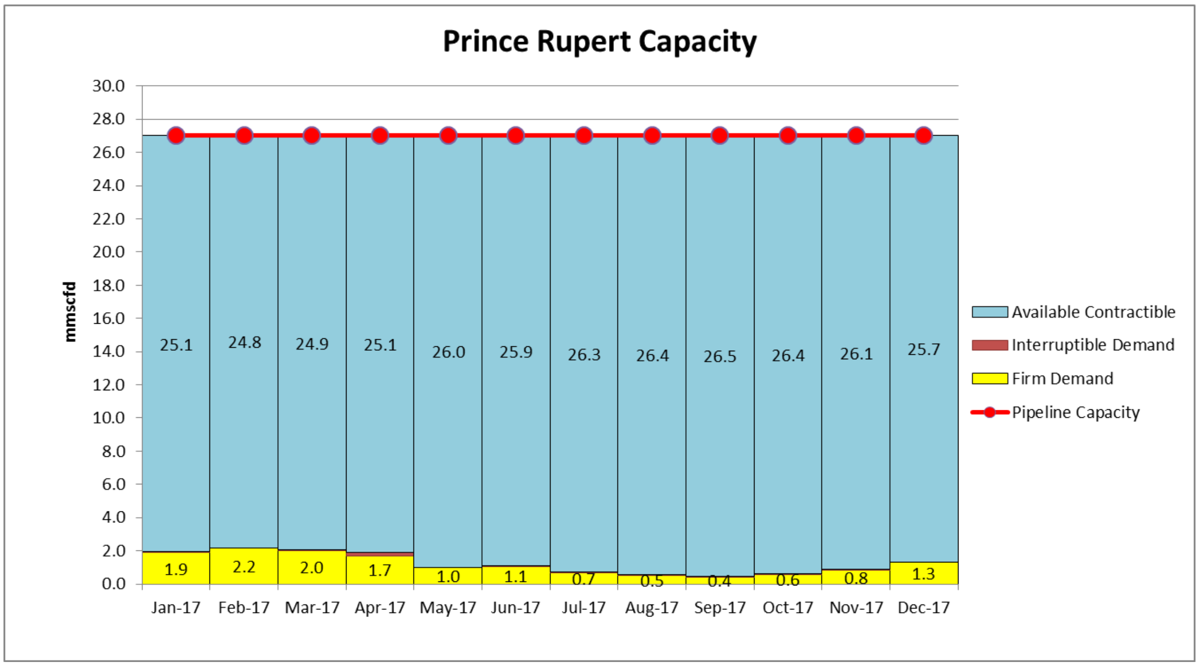
Please also see the response to Question 1.5.

1.7 Please provide a tabular and graphical representation of the monthly capacity demands (both firm and interruptible) of existing customers, the total contractible demand available and the total pipeline capacity under design year conditions.

Response:

Please see the following table and chart for capacity to the Prince Rupert area for 2017. PNG notes that its largest industrial customer in the Prince Rupert area had low demand during this period.

	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17
Firm Demand	1.91	2.16	2.03	1.71	0.99	1.06	0.68	0.53	0.43	0.55	0.83	1.31
Interruptible Demand	0.03	0.03	0.03	0.21	0.02	0.02	0.02	0.05	0.05	0.05	0.06	0.01
Available Contractible	25.06	24.82	24.94	25.08	25.99	25.92	26.29	26.42	26.53	26.40	26.11	25.67
Pipeline Capacity	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00	27.00



PNG states on page 5 of the Application it considers that locking in its uncontracted firm service capacity to the Ridley Island service area for a minimum of 20 years to be reasonable.

1.8 Please discuss whether, under the proposed terms of the letter agreement entered into between PNG and Triton on March 29, 2018 (Letter Agreement), it is possible that Triton could elect to continue to receive service from PNG at the Initial Capacity for the duration of the 20-year agreement term.

Response:

Yes, under the proposed terms of the Letter Agreement it is possible that Triton could elect to receive service from PNG at the Initial Capacity for the duration of the 20-year agreement term. Under Section 3 of the Letter Agreement, Triton has the ability to contract for up to 50 MMcf per day and would be able to contract for the Initial Capacity of 20 MMcf/day. However, Triton has indicated that the 20 MMcf/day is not a preferred option.

1.8.1 If yes, please explain whether the 20-year commitment at the negotiated Unit Demand Charge would put PNG's existing customers at risk of having to fund system reinforcements within the contract term, and why such a situation would be fair to existing customers.

Response:

PNG submits that the 20-year commitment at the negotiated Unit Demand Charge has a very low likelihood of putting PNG's existing customers at risk of having to fund system reinforcements within the contract term. As evidenced in PNG's response to BCUC Confidential IR No. 1.1.1, PNG submits that the negotiated unit demand charge is sufficient to address future system reinforcements.

PNG further states on page 3 of the Application that its "existing system will also require recommissioning in various segments upstream all the way to Summit Lake, BC."

1.9 Please confirm, or explain otherwise, that recommissioning of the existing system as referred to in the above preamble would only occur under the Expanded Capacity scenario (i.e. if Triton agrees to contract for greater than 20 MMcf/day of firm capacity).

Response:

Not confirmed. There are various levels of "recommissioning" depending on the capacity requirement. For background, the 20 MMcf/day case involves the scope described in the response to Question 1.2 which essentially brings all the units at R1 to current state, where they can operate at the nameplate capacity in a reliable manner. In addition, at a flow of 20 MMcf/day the system pressure will increase and thus some integrity digs and repairs would be required in certain locations. Further, as noted in response to Question 1.2, a 13 kilometre Interconnecting Pipeline would also be required in the area between Prince Rupert and Ridley Island under both the Initial Capacity and Expanded Capacity scenarios.

With the Expanded Capacity scenario (cases between 20 MMcf/day and approximately 50 MMcf/day), higher levels of recommissioning of the existing compressor stations and more pipeline integrity digs and repairs would be required. Depending on capacity requirements, some or all of the existing compressors would need re-activation and possible additional compressor locations downstream of Thornhill may be required. As noted above, a 13 kilometre Interconnecting Pipeline would also be required in the area between Prince Rupert and Ridley Island.

In all cases, between 20 MMcf/day and 50MMcf/day, there is no major looping required of the PNG West transmission system upstream of Terrace/Thornhill area. PNG plans to assess the technical requirements of the Expanded Capacity scenarios in more detail through the preliminary engineering studies identified in the Letter Agreement with Triton.

PNG states the following on page 5 of the Application:

> As noted in Exhibit A of the Letter Agreement, Triton will supply in kind to PNG the percentage of Company use gas required for the daily gas deliveries to Triton and currently estimated to be at most four percent. The four percent figure was sufficient when the PNG pipeline was operating at almost full capacity at the time Methanex's methanol facility was operating in the PNG service area. In other words, based on historical experience with a fully utilized pipeline, PNG is confident the quantity of Company use gas to be used by PNG to deliver gas to Triton will average at most approximately four percent of the total volume of gas delivered by PNG to Triton.

1.10 Aside from historical experience, please explain how PNG determined the four percent figure of Company use gas would be sufficient.

Response:

PNG's hydraulic model identifies the fuel requirements needed at the compressor stations. PNG believes that the 4% figure is reasonable for the state of development of the project. However, hydraulic calculations can provide greater accuracy and specificity. Depending on the scenario, Company use gas could be fractionally less or more than 4%. For example, in the maximum 50 MMcf/day case, the compressor fuel ratio could be up to 4.5% and for the 20 MMcf/day case the fuel ratio is approximately 1.1%. PNG notes that the Company use gas for the Expanded Capacity scenario will be addressed in PNG's Expanded Capacity proposal to Triton.

1.10.1 If no other analysis has been carried out, please explain why.

Response:

Please see the response to Question 1.10.

1.10.2 What is the probability that the percentage of Company use gas required to deliver gas to Triton will be greater than four percent?

Response:

If Triton were to take the high end of the capacity under review, it is possible it could be marginally higher than 4%. Please see the response to Question 1.10.

2.0 Reference: FIRM TRANSPORTATION SERVICE RATE
Exhibit B-1, Application, pp. 2–5
Negotiated unit demand charge

PNG states on page 3 of the Application that Triton is a wholly-owned subsidiary of the AltaGas Idemitsu Joint Venture Limited Partnership.

On page 4 of the Application, PNG states: "PNG and Triton have agreed to a minimum unit demand charge for the Initial Capacity…"

2.1 Please confirm, or explain otherwise, that Triton is a related, or non-arm's length, party to PNG.

Response:

Triton might be considered a related party to PNG by virtue of the fact that AltaGas Ltd., PNG's parent company and a related party, is a joint venture partner in the Triton LNG Limited Partnership. The other joint venture partner in Triton is Idemitsu Kosan Co. Ltd., an arm's length party to PNG.

2.1.1 If confirmed, please explain how the BCUC can be satisfied that the rate negotiated with Triton is reasonable when compared to a rate which PNG were to negotiate with an unrelated third party.

Response:

PNG is very cognizant of its relationship with its parent company and has followed the principles of its Code of Conduct in its dealings with Triton. As such, PNG submits that the rate negotiated with Triton is reasonable and would be the same rate that would be negotiated with an unrelated third party. Please also see the response to the BCUC Confidential IR No. 1.1.1.

PNG states the following on page 5 of the Application:

> PNG considers the proposed unit demand charge for PNG's existing initial capacity of 20 MMcf/day to be just and reasonable since, based on an internal analysis, the unit demand charge for the minimum 20 MMcf/day would result in lower tolls for existing customers. PNG also understands that the economic viability of a prospective LNG or methanol project at only 20 MMcf/day is very challenging and believes that Triton would prefer a higher delivery volume than PNG currently has available.

2.2 Please clarify if, based on the statements in the above preamble, the negotiated unit demand charge for PNG's existing Initial Capacity would not be considered reasonable if Triton were intending to continue to only contract for the Initial Capacity over the 20-year term of the agreement.

Response:

PNG submits that the negotiated unit demand charge for PNG's existing Initial Capacity would be considered reasonable even if Triton were intending to continue to only contract for the Initial Capacity over the 20-year term of the agreement. Please also see the response to BCUC Confidential IR No. 1.1.1.

2.3 Please discuss whether, if Triton continued to contract for only the Initial Capacity over the 20-year agreement term, the additional costs incurred to maintain the system and to serve Triton would result in higher tolls for existing customers over the long term. Please fully explain all assumptions made when providing this response.

Response:

PNG submits that if Triton continued to contract for only the Initial Capacity over the 20-year agreement term, the Unit Demand Charge is sufficient to cover the additional costs to maintain the system and would not result in higher tolls for existing customers over the long term. As evidenced in the response to BCUC Confidential IR No. 1.1.1, PNG has included maintenance costs in the system in its toll calculation and analysis.

3.0 Reference: REQUIRED APPROVALS
Exhibit B-1, Application, p. 6
Letter Agreement

PNG states it is requesting the BCUC approve the Letter Agreement on the condition that if Triton exercises its option to contract for firm gas service, PNG will file a fully executed definitive firm gas transportation service agreement that is "materially the same as the agreement contemplated under the Letter Agreement."

3.1 Please clarify what PNG means by "materially the same."

Response:

PNG's intent of this phrase is to mean that all the indicative terms in Exhibit A of the Letter Agreement would be the same in the executed Firm Gas Transportation Service Agreement (GTSA), however PNG is cognizant that there may be some minor wording changes in the executed GTSA.

3.2 Please discuss what potential non-material changes might be made to the fully executed firm gas transportation service agreement compared to the Letter Agreement.

Response:

Potential non-material changes that may be made to the fully executed GTSA might include changes to the definition of the inflation factor and other minor wording changes.

3.3 In the event that a material change was made, please discuss how PNG would address this situation with the BCUC.

Response:

PNG anticipates that in the event a material change was made, PNG would notify and file a subsequent application with the BCUC. However, PNG also notes that the GTSA will be filed with the BCUC for approval of the tariff within.

4.0 Reference: OPTION FEES
Exhibit B-1, Application, pp. 6–7
Calculation and treatment of option fees

4.1 Please explain how PNG determined the Initial Option Fee amount of $0.5 million and why this amount was considered appropriate.

Response:

PNG considered the Initial Option Fee amount of $0.5 million to be appropriate as this was based on previously approved option fees for the EDFT Application (Commission Order G-5-15), which were approximately $2 million for 80 MMcf/day, equivalent to $25,000 per 1 MMcf/day. Multiplying this unit amount by the Initial Capacity volume of 20 MMcf/day results in an Initial Option fee of $0.5 million.

4.2 Please explain how PNG determined the additional option fee amounts of $25,000 for each 1 MMcf/day of Expanded Capacity and why this amount was considered appropriate.

Response:

PNG applied the same option fee methodology used in the Initial Capacity for the Expanded Capacity and considers this to be appropriate. Please also see the response to Question 4.1.

PNG states the following on page 7 of the Application:

> If the option is exercised, the Option Fees paid will be credited to transportation service demand charges as per the Transportation Agreement. If the option is not exercised, PNG would keep the Option Fees and they would be available for use by PNG and its customers.
>
> PNG is requesting to record the Option Fees received in an interest bearing deferral account for future disposition either as a credit to transportation service demand charges if the option is exercised or as a credit to customers if the option is not exercised.

4.3 Please explain why PNG considers it appropriate to accrue carrying charges on the deferral account at PNG's short-term interest rate. As part of this response, please explain why carrying charges based on PNG's Weighted Average Cost of Capital or its Weighted Average Cost of Debt are not more appropriate.

Response:

In hindsight, PNG acknowledges that it should have proposed to accrue carrying charges on the deferral account at PNG's weighted average cost of debt as this balance is expected to remain in the deferral account for a period longer than one year. PNG is hereby proposing that the deferral account accrue carrying charges at PNG's weighted average cost of debt.

4.4 In the absence of an approved deferral account to record the Option Fees, how would PNG record these amounts for financial reporting purposes? Please provide the applicable US Generally Accepted Accounting Principles (GAAP) section(s) in support of this response.

Response:

In the absence of an approved deferral account, PNG would record the Option Fee amounts as a contract liability for financial reporting purposes. PNG submits that the Option Fees received represent cash receipts in advance of when related revenues are allowed to be recognized, as revenue is not recognized until goods or services are transferred to the customer.

Per FASB Account Standards Codification (ASC) 606-10-45-2, if a customer pays consideration, or an entity has a right to an amount of consideration that is unconditional (that is, a receivable), before the entity transfers a good or service to the customer, the entity shall present the contract as a contract liability when the payment is made or the payment is due (whichever is earlier). A contract liability is an entity's obligation to transfer goods or services to a customer for which the entity has received consideration (or an amount of consideration is due) from the customer.

4.4.1 As part of the above response, please explain why recording the Option Fees in accordance with US GAAP and without the use of a deferral account would not be more appropriate.

Response:

It is PNG's position that recording the Option Fees in a deferral account provides greater flexibility for the timing of the amortization of the deferral account to the benefit of PNG's customers.

For example, in a scenario whereby the option is not exercised, PNG would keep the Option Fees and they would be available for use by PNG and its customers based on applied-for and agreed-to timeline for future disposition. Under US GAAP (ASC 606-10-55-48), the unexercised contractual rights would require complete derecognition of that contract liability (and recognition of revenue) immediately, which would not allow for multi-year benefit from flexible amortization.

PNG also notes that using a deferral account would also accrue a return to the benefit of ratepayers at PNG's weighted average cost of debt. This would not be recorded if the option fees were recognized as a contract liability in accordance with US GAAP. Please also see the response to Question 4.3.