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

Via Web Upload and Courier

July 24, 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 Western LNG 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,

J.P. Kennedy

Requestor:	**Western LNG LLC**
Information Request Round:	**No. 1.**
To:	**Pacific Northern Gas Ltd.**
Date:	**July 12, 2018**
Application:	**Application to the British Columbia Utilities Commission for Approval of Letter Agreement between Pacific Northern Gas Ltd and Triton LNG Limited Partnership, dated March 29, 2018.**

1. Reference: Exhibit B-1, page 2 of 8.

"AltaGas […] has been collaborating with PNG since July 2015".

"representatives of AltaGas formally approached PNG in July 2017".

Reference: Exhibit B-5, page 3, para 8.

"AltaGas […] has been working jointly with PNG since July 2015".

"… AltaGas representatives also formally approached PNG in mid-2017".

1.1 What form did the collaboration between PNG and its corporate parent, AltaGas, take with respect to the utilization of PNG's capacity in the period July 2015 to July 2017? Please produce copies of the written correspondence, emails or other records in which AltaGas sought from, or was provided information by PNG during those two years, relating to the availability of and terms of access for pipeline capacity on the PNG system.

Response:

During 2015, PNG and AltaGas worked closely together on the utilization of PNG's capacity given AltaGas's involvement as a proponent of the proposed Douglas Channel LNG (DC LNG) Project near Kitimat. Post the withdrawal of the DC LNG Project on April 1, 2016, PNG continued to maintain regular communication with AltaGas in the form of monthly phone calls with key individuals in the AltaGas energy export group in order to gain market intelligence and develop strategies for utilizing the spare capacity.

Communication included conference calls and face-to-face meetings, in addition to hosting third parties interested in partnering with AltaGas to discuss their potential capacity requirements on PNG's system.

PNG is not providing copies of correspondence between PNG and AltaGas as the correspondence makes reference to projects that are confidential and include references to third parties with whom Confidentiality Agreements are in place. PNG also notes that the unutilized capacity on PNG's system is on the public record.

1.2 What form did the "formal approach" to PNG in July 2017 take? How was that approach distinguished from collaboration that had occurred in the previous two years? Please provide a copy of any written or electronic records evidencing the formal approach made by AltaGas in July 2017.

Response:

During the Spring and Summer of 2017, AltaGas requested information from PNG with respect to the scope and costs for PNG's mainline reactivation. The approach was formalized through the exchange of specifics regarding pipeline capacity to Prince Rupert, system upgrade scenarios and gas analysis. By July 2017, AltaGas had a favourable view of a prospective project and frequent meetings began to take place between the parties leading to the contract discussions.

PNG is not providing copies of the correspondence as the correspondence contains confidential information.

2. Reference: Exhibit B-1, page 2 of 8.

"AltaGas subsequently requested PNG to undertake investigative works to determine the feasibility and cost of delivering an additional 30 MMcf/day to Ridley Island for a potential total of approximately 50 MMcf/day of Transportation Service."

Reference: Exhibit B-5, page 3, para 9.

"… 'expanded capacity' in the letter agreement became tangible in late 2017 (through inclusion in the draft terms) …"

2.1 What was the date on which AltaGas "subsequently" requested the investigative works?

Response:

Requests with respect to the investigation of different aspects of PNG's system were made in Spring 2017 with requests for capacity studies to Prince Rupert being made in June 2017. More detailed investigative works were requested at the end of November 2017.

2.2 Which party prepared the first draft of the agreement to include a provision for expanded capacity of 50 MMcf/day?

Response:

PNG prepared the first draft of the letter agreement in late October 2017. Even though the expanded capacity was contemplated, PNG notes that this first draft did not include a provision for the expanded capacity of up to 50 MMcf/day as PNG had not yet completed a feasibility analysis to determine if it was capable of providing the expanded capacity.

The notion of "expanded capacity" was added to the letter agreement to more clearly articulate that PNG could only commit and provide the initial capacity with infrastructure presently in place and that an expansion project would be required to provide the "expanded capacity" subject to final cost projections and determination of a tariff for the entire 50 MMcf/day. The preliminary engineering works determined that 50 MMcf/day could likely be delivered with upgrades to PNG's system, subject to further engineering studies and system constraints.

2.3 On what day was that draft circulated to all parties to the transaction. Please produce a copy of that draft agreement and the correspondence under which it was transmitted.

Response:

The first draft of the Letter Agreement prepared in late October 2017 was circulated to AltaGas on November 16, 2017. The draft with the "expanded capacity" was circulated to all parties on December 6, 2017.

With respect to Western's request for the actual draft of the agreement, it is only the final version of the agreement for which PNG seeks approval. Further, in PNG's view, it would not be conducive to future negotiations with parties for drafts or communications exchanged during negotiations to become part of the information request process.

2.4 Prior to including the option for expanded capacity in the draft agreement, had PNG done any engineering work to determine what additional facilities would be required to deliver this greater volume to Prince Rupert? If so, please describe (a) the nature and timing of such work and (b) the cost incurred to undertake such work. In responding, please differentiate between facilities (a) between Summit Lake and Terrace and (b) between Terrace and Prince Rupert.

Response:

Prior to including the option for expanded capacity:

a) PNG had undertaken some preliminary hydraulic modelling and cost estimating (order of magnitude) to determine the nature of facilities specific to the expanded capacity.

b) For the facilities between Terrace and Prince Rupert, this preliminary work was done in November 2017. For the facilities between Summit Lake and Terrace, the scope relates to the partial recommissioning of PNG's existing system – this work was updated in September 2017 for PNG's purposes and was not directly attributable to the expanded capacity request.

c) For the hydraulic modelling and order of magnitude cost estimating for the expanded capacity option, PNG completed this work internally, with some assistance from an independent contractor (cost estimated at $2,000).

3. Reference: Exhibit B-5, page 3, para 9.

"… (a) the actual execution of the PNG – Triton Letter Agreement did not occur until March 29, 2018; and that (b) within the terms of the PNG – Triton Letter Agreement further study on the volumes between 20 MMcf/day to approximately 50 MMcf/day still had to be undertaken…"

3.1 Between the "formal approach" made by Triton to PNG in July 2017 and the execution of the Letter Agreement on March 29, 2018, did Triton make any payment to PNG to secure priority access to PNGs existing or expansion capacity?

Response:

PNG received no payments until the Letter Agreement was final and executed. PNG notes that funds have been placed into an escrow account as per the Letter Agreement.

3.2 Between July 2017 and March 29, 2018, did Triton make any legally enforceable commitments to PNG to make any future payments to PNG in connection with the use of either its existing or expanded pipeline capacity?

Response:

As noted in the Letter Agreement, Triton agreed to the option fees specified and also agreed to the Backstop Agreement for the reimbursement of the costs for the pipeline capacity expansion study to be undertaken by PNG.

4. Reference: Exhibit B-1, page 4 of 8.

"PNG and Triton have agreed to a minimum unit demand charge for the Initial Capacity…"

Reference: Exhibit B-1, Appendix A, Exhibit A.

References the "Unit Demand Charge" and "Base Interruptible Charge".

Reference: Exhibit B-5, page 13, footnote 43.

"The request for confidentiality is based on the consideration that the Triton Project may not go ahead, and that the public dissemination of this information may prove detrimental to PNG's position in future contractual arrangements and thus may have an adverse effect on its ability to negotiate the best possible arrangement on behalf of its customers."

4.1 What is the basis for the Triton confidential demand charge, i.e., how was it determined?

Response:

The Triton confidential demand charge was a rate negotiated with PNG only for the initial capacity of 20 MMcf/d. This was negotiated taking into account a number of factors including: tolls previously negotiated by PNG and approved by the Commission for its unutilized capacity, forecasted capital costs required for this capacity, ensuring lower tolls for existing customers, and taking into consideration the revenue to allocated cost ratio to determine a just and reasonable rate.

The demand charge was kept confidential as this could impede PNG in future negotiations with other parties. PNG notes that the final toll for Triton for the total capacity has yet to be determined and will also take the principles noted above into consideration. PNG plans to submit a CPCN and tariff application for the total capacity of the Triton project for Commission approval if Triton decides to move forward with the project.

4.2 What is the relationship between the Triton demand charge and the demand charge of other firm shippers? Please provide a table showing the demand charges for each firm shipper and the provisions under which it might change.

Response:

As noted in response to Question 4.1, PNG submits that the final Triton demand charge has not yet been determined. PNG has one large industrial firm shipper with an interim delivery rate of $3.0989/GJ, a low contract demand, and no long term commitment.

For reference, PNG has provided the table that follows showing all customer rates as of April 1, 2018:

Pacific Northern Gas

Vanderhoof to Prince Rupert / Kitimat Service Area

Rates Applicable to Each Gigajoule of Gas Delivered to Customers' Premises Effective April 1, 2018

Rate Class	Basic Monthly Charge $/Month	Delivery Charge $/GJ	Company Use Rider $/GJ	RSAM Rider $/GJ	Interim Rate Adjustment Rider $/GJ	Total Delivery Charge $/GJ	Commodity Charge $/GJ	GCVA Rider $/GJ	Total Commodity Charge $/GJ	Delivery + Commodity Charge $/GJ
Gas Sales:										
Residential (RS1)	**10.75**	12.615	(0.009)	0.551	0.000	13.157	2.034	(0.396)	1.638	**14.795**
Residential Propane (RS1P)[1]	**10.75**	7.222	N/A	N/A	0.000	7.222	15.552	5.446	20.998	**28.220**
Small Commercial (RS2)	**25.00**	10.620	(0.009)	0.551	0.000	11.162	2.030	(0.396)	1.634	**12.796**
Large Commercial (RS3)	**150.00**	8.521	(0.009)	N/A	0.000	8.512	2.030	(0.396)	1.634	**10.146**
Commercial Propane (RS2P)[1]	**10.75**	7.222	N/A	N/A	0.000	7.222	15.552	5.446	20.998	**28.220**
Small Industrial (RS4)	**410.00**	3.825	(0.009)	N/A	0.000	3.816	1.807	(0.396)	1.411	**5.227**
Commercial Interruptible (RS5)	**125.00**	5.217	(0.009)	N/A	0.000	5.208	1.448	(0.396)	1.052	**6.260**
Seasonal Off-Peak (Mar-Nov) (RS6)	**125.00**	7.540	(0.009)	N/A	0.000	7.531	1.340	(0.396)	0.944	**8.475**
Seasonal Off-Peak (Dec-Feb) (RS6)	**0.00**	15.492	(0.009)	N/A	0.000	15.483	1.340	(0.396)	0.944	**16.427**
Natural Gas Vehicles (RS7)	**10.75**	3.874	(0.009)	N/A	0.000	3.865	1.509	(0.396)	1.113	**4.978**
Transportation Service:										
Small Commercial (RS22)	**25.00**	10.620	(0.009)	0.551	0.000	11.162	N/A	N/A	N/A	**11.162**
Large Commercial (RS33)	**150.00**	8.521	(0.009)	N/A	0.000	8.512	N/A	N/A	N/A	**8.512**
Special Contracts:										
Rio Tinto Alcan	**0.00**	3.1079	(0.0090)	N/A	0.0000	3.0989	N/A	N/A	N/A	**3.0989**
BC Hydro	**4,819.47**	3.4077	(0.0090)	N/A	0.0000	3.3987	N/A	N/A	N/A	**3.3987**
Industrial Interruptible	**0.00**	3.4077	(0.0090)	N/A	0.0000	3.3987	N/A	N/A	N/A	**3.3987**

[1] Propane service is only available in Granisle, B.C.

4.3 What is the relationship between the Triton demand charge and (i) the incremental costs of providing service to Triton and (ii) recovery of sunk historic costs (stranded costs) for existing facilities?

Response:

PNG is unclear on the reference to recovery of sunk historic costs (stranded costs) for existing facilities. PNG reiterates that the final demand charge for Triton has not yet been determined, and that PNG will take into consideration the rate setting principles noted in response to Question 4.1 and ensure that the proposed toll provides economic benefits to existing ratepayers.

4.4 What is the interruptible toll to be charged Triton? What is the basis for this calculation?

Response:

The interruptible toll to be charged to Triton for the initial 20 MMcf/d is the same as the contract demand charge at 100 percent load factor. Please also see the responses to Questions 4.1 and 4.2.

5. Reference: Exhibit B-1, page 5 of 8.

"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."

Reference: Exhibit B-5, page 5, para 15.

"Triton itself has been in existence since 2013. Further the Triton Project itself is credible. In this regard, PNG understands that the Triton Project is using existing low cost modular technology, that market reception to the Project has been very positive, and that various project sites on Ridley Island are being evaluated."

5.1 Does PNG agree that the onsite facilities, operational expertise, markets and end-uses for methanol are largely distinct from those for LNG?

Response:

PNG has no opinion about the distinction between the characteristics of an LNG project or a methanol project. PNG's primary interest is the successful delivery of feedstock to the custody meter and in the case of a development project that the proponent has what PNG deems to be a credible project that presents an acceptable risk profile to proceed to commercial terms.

5.2 Has Triton entered into an engineering agreement with an EPC constructor to define the project?

Response:

It is PNG's understanding that Triton LNG is doing the engineering work for the project through a combination of third party and in house engineering. The project contemplates land-based stock design modules and the balance of the project will be constructed through a self-perform approach, making an EPC constructor unnecessary.

5.3 Please confirm that the basis for PNG's understanding that "market reception to the [Triton] Project has been very positive" is based on information provided by Triton. If not confirmed, please explain any independent basis for PNG's understanding that "market reception to the [Triton] Project has been very positive."

Response:

Confirmed.

5.4 Has Triton determined which market (LNG or methanol) it is pursuing? Which market has given the "very positive" reception described above?

Response:

It is PNG's understanding that Triton LNG is pursuing the LNG market and that the LNG market has received the project very positively. PNG also notes that one of the Triton partners, Idemitsu Kosan, has over 100 years of experience in the global energy market and has extensive LNG off-taker relationships in Asia.

5.5 Please confirm that, while "various project sites on Ridley Island are being evaluated," no project site had been finalized (a) at the time the Letter Agreement was executed, and (b) at the time the Application was filed with the BCUC.

Response:

Confirmed. It is PNG's understanding from Triton LNG that given the number of site options available at Ridley Island, the site is not considered a critical path item and thus no project site was finalized when Triton LNG committed to financially backstop the PNG engineering study. Further, AltaGas is currently completing construction of its RIPET Project and is very familiar with the area.

6. Reference: Exhibit B-1, page 8.

"Triton has emphasized the need for a prompt review of this Application as they are endeavouring to obtain commitments from various parties to make their project a success."

Reference: Exhibit B-5, page 5, para 17.

"Triton has emphasized the need for a prompt review of the Application as it is endeavouring to obtain commitments from the various parties to make its project a success."

6.1 Between the filing of Exhibit B-1 on April 9, 2018 and the filing of Exhibit B-5 on June 21, 2018, has PNG obtained from Triton evidence of any progress in obtaining commitments from various parties to make its project a success?

Response:

PNG has had verbal discussions with AltaGas, as a representative of Triton, on the positive progress of the Triton project. Please also see the letters included in response to Question 7.4 which support the positive updates that AltaGas has shared with PNG.

6.2 What parties did PNG take Triton to be referring to when it emphasized the need for a prompt review?

Response:

It is PNG's understanding that Triton was simply expressing its desire for a prompt filing and response from the Commission in order that it could continue to develop the project with a high degree of certainty. It is also PNG's understanding that Triton LNG considers the acquisition of sufficient PNG capacity as a critical path item in the development process.

6.3 What direct communication has PNG had with those parties in connection with the Triton project?

Response:

Please see the response to Question 6.2. PNG does not have direct communication with these parties.

6.4 Which party would be the shipper on the PNG pipeline--Triton or Triton's customers?

Response:

PNG's contractual arrangements are with Triton as shipper on the PNG pipeline.

6.5 Has PNG had any conversations with potential customers of Triton? If so, were these potential customers for methanol or LNG?

Response:

As PNG's contractual arrangements are with Triton as the shipper on the PNG pipeline, PNG's conversations have been with Triton representatives. As noted in response to Question 5.1, PNG's primary interest is the successful delivery of feedstock to its customer's custody meter.

7. Reference: Exhibit B-5, page 7, para 24.

"During a January 25, 2018 meeting with Western at PNG offices, PNG learned that Western had no project site and had not made any contact with the Haisla…"

7.1 Please confirm that during the January 25, 2018 meeting, PNG was advised by Western that Western was meeting with the Haisla on the following day—January 26, 2018—in Kitimat. Please further confirm that, subsequent to January 25, 2018, PNG was advised by Western that this meeting with the Haisla did take place.

Response:

PNG confirms that Western did inform PNG on January 25, 2018 that it was meeting with the Haisla on the following day, and that Western confirmed a meeting took place on January 26, 2018. PNG notes that Western indicated that no specific progress was made towards securing a project site in Kitimat and that no formal process had been initiated to begin the consultation process with First Nations.

PNG notes that it has local knowledge of Kitimat, including its stakeholders, the difficulty of the terrain in the region, and the importance of involving the Haisla First Nations in any projects in the region. PNG had conveyed this information to Western in its early telephone discussions.

7.2 At the time of Triton's "formal approach" to PNG in July 2017, did Triton indicate it had (a) a project site and/or (b) some form of benefit agreement with any First Nation that might be affected by its proposed project? Did Triton provide any evidence it had commenced consultation with any First Nation in that regard?

Response:

Triton did not indicate that it had formally secured a project site or a benefit agreement with any First Nation that may be impacted by the project. PNG understood, however, that Triton was considering a site on Ridley Island and that Triton LNG's partner, AltaGas has existing and established business relationships with Ridley Terminals Inc. and Royal Vopak.

PNG also notes that AltaGas has been an infrastructure developer in British Columbia for over 20 years and had recently successfully undertaken the development of the liquefied propane terminal on Ridley Island, a project that necessarily involved successful consultation and engagement as well as an ongoing relationship with First Nations in the area. It is PNG's understanding that Triton's plan with respect to First Nation engagement has been informed by AltaGas' experience in the area and that there has been ongoing dialogue between AltaGas and First Nations impacted by infrastructure projects at Ridley Island. Please also see the response to Question 5.5.

7.3 At the time PNG entered into the option agreement with Triton on March 29, 2018, did Triton indicate it had (a) a project site and/or (b) some form of benefit agreement with any First Nation that might be affected by its proposed project? Did Triton provide any evidence it had commenced consultation with any First Nation in that regard?

Response:

Please see the responses to Question 5.5 and Question 7.2.

7.4 Since March 29, 2018 has Triton advised PNG that is has (a) acquired a project site, (b) determined the type of project it proposed to undertake, (c) determined the amount of pipeline capacity it will at minimum require and/or (d) concluded some form of benefit agreement with any First Nation that might be affected by its proposed project?

Response:

For parts (a), (b) and (d) please refer to the responses to Question 5.5 and Question 7.2. For Part (c) please refer to the Letter Agreement.

Letters of support for the Triton LNG project were received from the Lax Kw'alaams Band, the Metlakatla First Nation, and the Prince Rupert Port Authority. For reference, these have been reproduced on the pages that follow.

Lax Kw'alaams Band
206 Shashaak Street,
Lax Kw'alaams BC V0V 1H0
Telephone:(250) 625-3293
Fax: (250) 625-3246

Lax Kw'alaams Band
100 1st Ave East
Prince Rupert BC V8J 1A6
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July 19, 2018

Ms. Janet P. Kennedy
Vice-President, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
2550-1066 West Hastings Street
Vancouver, BC V6E 3X2
jkennedy@png.ca

Re: Triton LNG Limited Partnership ("Triton LNG") Project

Dear Ms. Kennedy:

I am writing on behalf of Lax Kw'alaams Band, which holds unextinguished aboriginal rights in the Ridley Island area. Lax Kw'alaams Band has been successfully involved in the development of the Ridley Island Propane Export Terminal, working with the proponent to create an atmosphere of mutual respect and cooperation. While additional engagement about the Triton LNG project will be necessary, Lax Kw'alaams Band is generally supportive of projects like the Triton LNG project that have the potential to generate significant benefits for Lax Kw'alaams Band and its members. Given the relationships fostered through the development of the Ridley Island Export Terminal, the Lax Kw'alaams Band expects that it will be able to productively work with Triton LNG in the development of its project on Ridley Island and looks forward to continued discussions in that regard.

Yours truly,

Mayor John Helin
Lax Kw'alaams Band

Metlakatla First Nation

Ms. Janet P. Kennedy
Vice-President, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
2550-1066 West Hastings Street
Vancouver, BC V6E 3X2
jkennedy@png.ca

Re: Triton LNG Limited Partnership ("Triton LNG") Project

Dear Ms. Kennedy:

I am writing on behalf of Metlakatla First Nation, which holds unextinguished aboriginal rights in the Ridley Island area. Metlakatla First Nation has been successfully involved in the development of the Ridley Island Propane Export Terminal, working with the proponent to create an atmosphere of mutual respect and cooperation. While additional engagement about the Triton LNG project will be necessary, Metlakatla First Nation is generally supportive of projects like the Triton LNG project that have the potential to generate significant benefits for the Metlakatla First Nation. Given the relationships fostered through the development of the Ridley Island Export Terminal, Metlakatla First Nation expects that it will be able to productively work with Triton LNG in the development of its project on Ridley Island and looks forward to continued discussions in that regard.

Yours truly,

Chief Harold Leighton for

PRINCE RUPERT
PORT AUTHORITY
LINKING A WORLD OF OPPORTUNITY

24 July 2018

Ms. Janet P. Kennedy
Vice-President, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
2550-1066 West Hastings Street
Vancouver, BC V6E 3X2
jkennedy@png.ca

Re: Pacific Northern Gas Ltd. ("PNG") – Pacific Northern Gas Ltd. and Triton LNG Limited Partnership ("Triton LNG") Letter Agreement Application- Comments of the Port of Prince Rupert Authority ("PRPA")

Dear Ms. Kennedy:

It is the PRPA's understanding that PNG has applied for approval of a Letter Agreement between itself and Triton LNG that addresses an option for capacity on PNG's system and that this capacity relates to Triton LNG's proposed liquefaction terminal project that is to be located on Ridley Island. PRPA wishes to express its support for initiatives that would see the development of liquefaction terminals in the Prince Rupert area. In particular, PRPA is interested in projects, like the one that Triton LNG proposes, as it brings LNG to the Prince Rupert area and in addition to exports, can provide LNG to support trucking and marine activities, lowering our reliance on diesel fuel and providing GHG reductions to the community. Combined these are significant benefits for Prince Rupert and the province of BC.

The PRPA is responsible for the overall planning, development, marketing and management of the commercial port facilities within Prince Rupert. The PRPA has successfully worked with Ridley Island LPG Export Limited Partnership, a partnership formed between a subsidiary of AltaGas Ltd. and Vopak Development Canada Inc., in the development of the Ridley Island Propane Export Terminal ("RIPET") Project, the first propane export terminal on Canada's west coast. Having secured the necessary regulatory and environmental approvals, as well as the appropriate tenure for the terminal site, the construction of RIPET is expected to be completed in the next year. In PRPA's view, the construction of RIPET demonstrates the opportunities for successful completion of export terminals in the Prince Rupert area. The PRPA looks forward to working with Triton LNG to move its proposed project forward.

Yours truly,

Shaun Stevenson
Vice President, Trade Development and Public Affairs

8. Reference: Exhibit B-5, page 6, para 21.

"… (PNG notes that the first contact by Western was initiated on October 24, 2017) and a non-disclosure agreement (NDA) with Western was not entered into until November 10, 2017.

Reference: Exhibit B-5, pages 6-7, paras 23 and 25.

"PNG made clear to Western that it was not alone in seeking capacity. It also let Western know on several occasions that PNG had to complete its arrangements with the first proponent that was ahead of Western."

"… starting in late October and November 2017 PNG has had a flurry of requests for meetings with various parties seeking potential capacity on PNG's pipeline."

8.1 Does PNG consider that a "formal approach" has been made by Western to PNG for existing or expansion capacity on its system?

Response:

Yes, PNG considers that a "formal approach" has been made by Western for existing or expansion capacity on its system. PNG and Western have been in discussions and negotiating an option agreement.

8.2 If for any reason Triton either does not obtain or decides not to exercise an option to use existing or expansion capacity on the PNG system, does PNG consider that Western currently has first priority access to the existing and initial expansion capacity of the pipeline? Is Western "ahead" of other parties in the manner that PNG views Triton as being "ahead of Western"?

Response:

If Triton either does not obtain or decides not to exercise an option to use existing or expansion capacity on the PNG system and subject to further due diligence, PNG would consider that Western currently has first priority access to the existing capacity of the pipeline subject to continued good faith negotiations and timely execution of agreements with terms and conditions that are acceptable to PNG and subject to Commission approval.

While PNG considers Western to be "ahead" of other parties on existing capacity, PNG notes that since the filing of this Application, PNG has had numerous discussions with other third parties who have expressed an interest in PNG's existing and expansion capacity. Given the increased interest in the expansion capacity on the mainline and PNG's current view of the complexity of the mainline expansion, PNG may need to consider other customer requests for future project expansion, not just the request of Western alone.

Beyond existing capacity in the system, PNG would have to undertake a significant upgrade to the trunk line part of the pipeline from Summit Lake. Consequently, PNG would need to ensure the appropriate system design is planned and completed in a systematic fashion to provide cost-effective and reliable service to its customers. For clarity, the Triton project is largely using existing mainline infrastructure with some system upgrades to the existing system, rather than large looping on the mainline, which is an important distinction from a project development perspective (i.e. system upgrades versus an expansion project).

8.3 Are there any provisions in PNG's tariff which determine the process by which access to the pipeline system is allocated amongst competing potential customers where aggregate requests exceed available capacity? Explain how PNG has, or would, determine which requests for existing unused capacity would be met if aggregate requests exceeded available capacity.

Response:

PNG's Gas Sales Tariff which sets the General Terms and Conditions under which PNG provides service to its customers does not have any provisions to determine a process by which access to the pipeline system is allocated amongst competing potential customers where aggregate requests exceed available capacity. PNG submits that it would not contract for capacity that is not available. However, PNG would work with potential customers to determine if an expansion to its existing facilities is feasible to provide additional capacity to all interested parties at a rate that is just and reasonable and not unduly discriminatory, while applying the Utility System Extension Test Guidelines and adhering to the regulations under the *Utilities Commission Act*.

8.4 Are there tariff provisions, guidelines, practices or procedures that govern how PNG canvasses potential interest in use of its system before allocating existing capacity on a firm contractual basis and/or undertaking expansions? If so, please produce a copy of such written tariff provisions, guidelines, practices or procedures.

Response:

PNG is not aware of such tariff provisions, guidelines, practices or procedures.

8.5 What steps have been taken by PNG to canvass potential interest in use of its system since receiving a "formal approach" from Triton in July 2017?

Response:

PNG continues to discuss its capacity with potential project proponents and has received additional inquiries that PNG considers may result in credible projects. All these inquiries, should they wish to discuss further, would be behind Western subject to how Western wishes to proceed.

8.6 What steps were taken by PNG to canvass potential interest in use of its system prior to entering into the option agreement with Triton on March 29, 2018?

Response:

PNG has never ceased exploring the possibilities for utilizing its available capacity at various points on its system. Please also see response to IR 8.5..

8.7 What are the tariff provisions regarding tolls if there is an expansion or the addition of new firm shippers for existing capacity?

Response:

PNG is not aware of any toll provisions for an expansion or the addition of new firm shippers for existing capacity in its tariff. As a public utility, PNG is subject to legislation under the *Utilities Commission Act*. As such, any expansion capital requirements or new rate schedules for customers are subject to a regulatory review and approval by the Commission.

8.8 What are the tariff provisions regarding tolls for existing firm shippers? Do their tolls vary with volumes? If so, how? If not, why not?

Response:

As a public utility, PNG files annual or bi-annual Revenue Requirements Applications and seeks approval for any proposed rate changes. The proposed rates (tolls) for all customer classes will vary depending on the annual forecast cost of service and forecast deliveries and any rate changes are subject to a regulatory review and approval by the Commission. PNG notes that any revenue deficiencies or sufficiencies are primarily allocated to customer classes using forecast normalized gross margin as the allocator.

The tolls vary depending on the customer rate category and not necessarily by volume. PNG notes that some customer rate categories vary with volumes. For example, commercial customers can either be small commercial (less than 5,500 annual GJ consumption) or large commercial (minimum 5,500 annual GJ consumption).

8.9 What are the tariff provisions for interruptible rates? Do interruptible tolls vary with firm volumes? If so, how? If not, why not?

Response:

As noted in response to Question 8.8, customers with interruptible rates will also be subject to rate changes arising from PNG's annual revenue requirements applications and any revenue deficiencies or sufficiencies will be allocated its pro-rata share using the forecast normalized gross margin as the allocator.

The interruptible tolls do not vary with firm volumes, but PNG notes that there is a relationship between an interruptible rate and a customer class. For example, interruptible rates for industrial customers are lower than interruptible rates for commercial customers.

8.10 What is the disposition of interruptible revenues? Do interruptible revenues benefit firm shippers?

Response:

In its bi-annual revenue requirements applications, PNG incorporates its best forecast of deliveries from all customer classes, including interruptible customers, and incorporates their impact on the calculated revenue deficiency or sufficiency. Therefore, the interruptible revenues that are included in the forecast would "benefit" existing firm shippers as it would impact all existing customer classes.

9. (1) Reference: *Phase I Gas Transportation Tariff of Foothills Pipe Lines Ltd.,* "Capacity Allocation Procedures" (December 1, 2012) at parts 3 and 4
http://www.tccustomerexpress.com/docs/fh_regulatory_tariff/04_capacity_allocation_procedures.pdf

9.1 Having regard to Reference (1) above, please confirm that the terms and conditions that the National Energy Board (NEB) has authorized Foothills Pipe Line Ltd. (Foothills) to offer firm long term service using existing capacity on the Foothills Pipe Line System (Foothills System) include the following provisions:

4.1.1 Posting of Existing Capacity

If Company determines that Existing Capacity is available or will become available in Zone 8 or Zone 9, Company shall provide notice on its website, within a reasonable period of time after such determination, regarding the availability of such Existing Capacity. At least three (3) Banking Days after such notice, Company shall post on its website (or by any other alternative method determined by Company, if Company's website is inoperable) on a Banking Day (excluding statutory holidays in the United States) (the "Existing Capacity Open Season"):

(a) the quantity of Existing Capacity which is available for such Existing Capacity Open Season;

(b) the Service Commencement Date(s) for such Existing Capacity which shall be no later than 12 months from the date such Existing Capacity is posted; and

(c) the Closing Date for such Existing Capacity Open Season.

4.1.4 Awarding of Existing Capacity

Subject to subsections 4.1.3 and 4.1.5, Existing Capacity shall be awarded to the Prospective Shipper whose bids are accepted by Company as follows:

(a) Company shall rank the bids in descending priority based on the following criteria:

(i) firstly, on the Requested Term (where the bid with the longer term shall have the higher priority); and

(ii) second, by the Requested Service Commencement Date (where the bid with the earlier Requested Service Commencement Date shall have the higher priority).

(b) Subject to subsection 4.1.4(d), Company shall award Existing Capacity to the bids in sequential order, based on the priority established pursuant to subsection 4.1.4(a), until all the bids have been processed or until all Existing Capacity has been awarded;

(c) Subject to subsection 4.1.4(d), if two or more bids have the same priority and the Existing Capacity is not sufficient to provide the total Requested Maximum Daily Delivery Quantity, then the Existing Capacity shall be awarded to such bids on a pro rata basis based on the Requested Maximum Daily Delivery Quantity of each bid;

(d) If the Existing Capacity to be awarded to a bid as determined by Company in either subsection 4.1.4(b) or subsection 4.1.4(c) is less than the Requested Minimum Daily Delivery Quantity as set out in such Bid Form, that bid shall be deemed to be rejected by Company and no Existing Capacity shall be awarded to such bid. The remaining Existing Capacity shall continue to be awarded sequentially to the remaining bids based on the priority established pursuant to subsection 4.1.4(a), until all the bids have been processed or until all Existing Capacity has been awarded; and

(e) Company shall be deemed to have accepted the bids of Prospective Shippers when Company awards Existing Capacity to such Prospective Shippers. Company shall notify such Prospective Shippers who have been awarded Existing Capacity within 3 Banking Days from the Closing Date.

4.1.5 Requirements for Existing Capacity

Where Company awards Existing Capacity to a Prospective Shipper pursuant to subsection 4.1.4, such Prospective Shipper shall, at the request of Company:

(a) execute, within the time period specified by Company, a Service Agreement, Firm Transportation Service, including Appendix A to that agreement, for the provision of the transportation service awarded;

(b) provide sufficient financial information to demonstrate its creditworthiness;

(c) provide a Financial Assurance to Company if requested pursuant to subsection 5.8 of the General Terms and Conditions of this Gas Transportation Tariff; and

(d) demonstrate to the satisfaction of Company that it has appropriate upstream and downstream transportation arrangements.

Response:

PNG confirms that the quoted provisions are included as a portion of Foothills Pipe Lines Ltd.'s tariff on file with the NEB.

9.2 Having regard to Reference (1) above, please confirm that the terms and conditions that the NEB has authorized Foothills to offer firm long term service when expansion facilities are required to provide that service on the Foothills System include the following provisions:

3.3 Expansion Capacity

3.3.1 Where Company determines that the Existing Capacity is insufficient to meet the Request for Service from Prospective Shippers in the queue and that the demand for service is sufficient to consider an expansion of existing facilities ("New Facilities"), Company shall advise each Prospective Shipper in the queue of the minimum term required for service through the New Facilities ("Minimum Term") which shall, unless circumstances dictate otherwise, be 10 years. Company may request each Prospective Shipper in the queue to complete and return to Company, within 30 days of the receipt by Prospective Shipper, a Project Status Summary in the form set forth in Appendix A to these Capacity Allocation Procedures. Any Prospective Shipper whose Request for Service does not indicate that such Prospective Shipper requires service for the Minimum Term will be required to confirm in writing to Company, within the time period provided for completing and returning the Project Status Summary, that such Prospective Shipper agrees to take service for a term not less than the Minimum Term. Prospective Shippers who fail within the time period provided to complete and return a Project Status Summary and, if applicable, provide confirmation that such Prospective Shippers agree to take service for a term not less than the Minimum Term will move to the bottom of the queue. In the event that two or more Prospective Shippers fail to complete and return the Project Status Summary and Minimum Term confirmation, if applicable, within the time period provided, such Prospective Shippers shall retain the same priority each had in relation to the other, on the date Company advises Prospective Shippers of the Minimum Term, when such Prospective Shippers are moved to the bottom of the queue.

4.3.1 Posting of Expansion Capacity

If Company determines that demand for service under Rate Schedule FT, Firm Transportation Service may be sufficient to consider expansion of existing facilities on Zone 8 or Zone 9 ("Expansion Capacity"), Company shall provide notice on its website of the open season for such Expansion Capacity. At least three Banking Days after such notice, Company shall post on its website (or by any other alternative method determined by Company, if Company's website is

inoperable) on a Banking Day (excluding statutory holidays in the United States)(the "Expansion Capacity Open Season"):

(a) the date such Expansion Capacity may be available; and

(b) the Closing Date for such Expansion Capacity Open Season.

Response:

PNG confirms that the above referenced provisions are included in Foothills Pipe Lines Ltd.'s tariff on file with the NEB.

(2) Reference: *Maritimes & Northeast Pipeline Limited Partnership NEB Gas Tariff,* "General Terms and Conditions" (December 4, 2009), at part 4, online: https://infopost.spectraenergy.com/infopost/MNCAHome.asp?Pipe=MNCA

9.3 Having regard to Reference (2) above, please confirm that the terms and conditions that the National Energy Board (NEB) has authorized Maritimes and Northeast Pipeline Limited Partnership. (MNPLP) to offer firm long term service using existing capacity on the Maritime and Northeast PipeLine (MNP) include the following provisions:

4.2 Unsubscribed Capacity

(a) Subject to requirements for requests for firm service in the GT&C and project financing requirements, firm capacity that is available but is not currently subscribed will be allocated to that request(s) generating the highest net present value to Pipeline. Net present value will be determined based on the discounted cash flow of revenues to Pipeline produced, lost, or affected by the request(s) for service. In determining the highest net present value, Pipeline will consider objective criteria only. Such criteria may include, without limitation, the maximum contract quantity requested, the term of the service requested, the date on which the requested service would commence, and such other objective criteria available based on the requests for service received by Pipeline. The net present value evaluation shall include only revenues generated by the reservation charge component exclusive of any discounts. The net present value discount factor used by Pipeline will be applied consistently to all requests for capacity being evaluated at a particular point in time.

(b) For request(s) for firm service, provided that capacity is available to satisfy any such request(s), Pipeline shall conduct an open season and shall post the notice of such open season within twenty-four (24) hours of receiving the request(s) for firm service. To the maximum extent possible, Pipeline will attempt to structure any such posting so as not to identify specifically the customer or potential customer submitting the request and/or the specific location of the market(s) to be served. Any open season pursuant to this Section 4.2 will be conducted to determine which Customer or potential customer values any available capacity the most.

(c) For any open season conducted pursuant to this Section 4.2 such open season shall be held for a minimum of: (i) two (2) Business Days for service offerings with a term of less than one (1) year; or (ii) fifteen (15) Business Days for service offerings

with a term of one (1) year or more. In no event shall the open season be for a period greater than one (1) Month. All open seasons shall end at 2:00 p.m. CT not less than two (2) Business Days prior to the date service would be available. Any such posting shall, at a minimum, describe the service available, the date(s) that the service will be available, the duration for which the service will be available, the capacity path, any minimum terms and conditions, any other factors Pipeline shall consider in evaluating requests received during the open season, and any other rules applicable to the open season procedure.

Response:

PNG confirms that the above referenced provisions are included in Maritimes & Northeast Pipeline Limited Partnership's tariff on file with the NEB.

9.4 Having regard to Reference (2) above, please confirm that the terms and conditions that the NEB has authorized MNPLP to offer firm long term service using expansion facilities required for that purpose on the MNP include the following provisions:

4.3 Capacity Created as a Result of Constructing Additional Facilities

(a) All Customers and potential customers are put on notice that Pipeline may, but is not required to, from time to time, in addition to constructing facilities under GT&C Article 17, conduct periodic open seasons for the purpose of evaluating market interest to expand and/or extend Pipeline's transportation system. If Pipeline does conduct an open season, any additional pipeline capacity made available by such expansion and/or extension will be allocated under the terms and conditions of such open season.

(b) If Pipeline conducts an open season for pipeline capacity associated with the facilities of Maritimes & Northeast Pipeline, L.L.C. or any other downstream pipeline, Pipeline shall make reasonable efforts to coordinate such open season with Maritimes & Northeast Pipeline, L.L.C. or other downstream pipeline, respectively.

Response:

PNG confirms that the above referenced provisions are included in Maritimes & Northeast Pipeline Limited Partnership's tariff on file with the NEB.

9.5 Having regard to Reference (2) above, please confirm that the terms and conditions that the NEB has authorized MNPLP to offer firm long term service using expansion facilities required for that purpose on the MNP include the following provisions:

5. Service Nomination Procedure

5.1 Customer shall furnish or cause to be furnished to Pipeline nominations showing the quantity of gas to be received and delivered by Pipeline, by individual Point of Receipt and individual Point of Delivery, for each Day of the Nomination Period as required below:

(a) Such nomination shall reflect Customer's contract number; the beginning and ending dates of the period for which the deliveries are desired, provided the nomination beginning and ending dates are within the term of Customer's contract; the quantity of gas to be received, including Fuel Retainage Quantity and any make-up quantity pursuant to Articles 8 or 11, at each Point of Receipt and the quantity of gas to be delivered at each Point of Delivery on Pipeline. Such nomination shall also specify such information as Pipeline reasonably determines necessary to perform service. To the extent Customer desires to change its nomination for any Nomination Period, Customer must submit a new nomination for such Nomination Period to replace in its entirety the prior nomination. When a nomination for a date range is received, each Day within that range is considered an original nomination. When a subsequent nomination is received for one or more Days within that range, the previous nomination is superseded by the subsequent nomination only to the extent of the Days specified. The Days of the previous nomination outside the range of the subsequent nomination are unaffected. Nominations have a prospective effect only.

5.3 Other Nomination Cycles

(a) <u>Evening Nomination Cycle.</u> Subsequent to the Timely Nomination Cycle, as described in Section 5.2, Customer may alter its nominations provided that the nomination given by Customer to Pipeline for deliveries starting at 9:00 a.m. CT on the following Day shall be submitted to Pipeline no later than the time specified in the nomination timeline below, or such lesser period as is acceptable to Pipeline. Any nomination submitted after the Timely Nomination Cycle shall contain Customer's service requirements for one Day only and shall include the effective date and time. Intraday nominations do not replace the remainder of a standing nomination. The nomination timeline shall be Central Time on the Day prior to gas flow:

6:00 p.m. Nomination leaves control of the nominating party

6:15 p.m. Receipt of nomination by Pipeline through the ECS

6:30 p.m. Quick response by Pipeline regarding validity of data elements of nominations received through the ECS at 6:15 p.m.

9:00 p.m. Receipt of completed confirmations by Pipeline from upstream and downstream connected parties

10:00 p.m. Provide scheduled quantities to Customer, point operator and bumped parties (notice to bumped parties)

Response:

PNG confirms that the above referenced provisions are included in Maritimes & Northeast Pipeline Limited Partnership's tariff on file with the NEB.

(3) Reference: *Gas Transportation Tariff of Nova Gas Transmission Ltd.*, "Appendix 'A' - Terms and Conditions Respecting Access to Transportation Service at Group 1 Delivery Points" (December 1, 2012), online: http://www.tccustomerexpress.com/docs/ab_regulatory_tariff/ngtl-gtt-appendix-a.pdf

9.6 Having regard to Reference (3) above, please confirm that the terms and conditions that the National Energy Board (NEB) has authorized Nova Gas Transmission Ltd. (Nova) to offer firm long term service using existing capacity on the Nova System include the following provisions:

2.1 Posting of Existing Capacity

If Company determines that capacity is available or may become available for Service under Rate Schedule FT-D that does not require new Facilities ("Existing Capacity"), Company shall provide Notice on the Website of the open season for such Existing Capacity (the "Existing Capacity Open Season"). At least 3 Banking Days (excluding statutory holidays in the United States) after such Notice, Company shall post on the Website:

(a) the quantity of Existing Capacity available at the Group 1 Delivery Point;

(b) the date such Existing Capacity will be available; and

(c) the Closing Date for such Existing Capacity Open Season.

2.2 Existing Capacity Bid Process

If Company posts Existing Capacity pursuant to paragraph 2.1, prospective customers may bid for such Existing Capacity, on any Banking Day up to and including the Closing Date, as follows:

(a) Prospective customers shall submit a completed and unedited bid form, in the form set out in article 6.0 (the "Open Season Bid Form");

(b) The requested term of Service, as established by the requested Service Commencement Date and requested Service Termination Date, each set out on the Open Season Bid Form, shall be a minimum term of one year;

(c) All bids shall be irrevocable and must be received by Company by 11:00 hours CCT on the Closing Date;

(d) Within 2 Banking Days of the Closing Date, prospective customers, except those who are also Customers receiving

Service, other than Service under Rate Schedule IT-S or Rate Schedule FT-X, shall provide to Company for each Open Season Bid Form, a deposit equal to the lesser of:

(i) one month demand charges for the Delivery Contract Demand set out on the Open Season Bid Form; or

(ii) $10,000.

The deposit, if provided, shall be refunded to unsuccessful bidders within 5 Banking Days from the date the Service Agreements and Schedules of Service under Rate Schedule FT-D are executed for all Existing Capacity posted in the Existing Capacity Open Season.

If Company awards Existing Capacity to a prospective customer and such customer executes the Service Agreement and Schedule of Service under Rate Schedule FT-D for such Existing Capacity, the deposit, if provided, will be credited to the bill for the first month of Service or returned to the Customer if requested.

If Company awards Existing Capacity to a prospective customer who is also a Customer receiving Service, other than Service under Rate Schedule IT-S or Rate Schedule FT-X, and such prospective customer fails to meet the requirements for Existing Capacity set out in paragraph 2.5, the Existing Capacity awarded to such prospective customer shall be withdrawn and such prospective customer shall pay Company an amount equal to the lesser of:

(i) one month demand charges for the Delivery Contract Demand set out on the Open Season Bid Form; or

(ii) $10,000.

…

2.4 Awarding of Existing Capacity

Subject to paragraphs 2.3 and 2.5, Existing Capacity shall be awarded to the prospective customers whose bids are accepted by Company as follows:

(a) Company shall rank the bids in descending priority based on the following criteria:

(i) first, on the basis of the per unit product of the current FT-D Demand Rate multiplied by the requested term (where the bid with the highest per unit product shall have the higher priority); and

(ii) second, by the Service Commencement Date (where the bid with the earlier Service Commencement Date shall have the higher priority).

…

Response:

PNG confirms that the above referenced provisions are included in NOVA Gas Transmission Ltd.'s tariff on file with the NEB.

9.7 Having regard to the Reference (3) above, please confirm that the terms and conditions that the NEB has authorized Nova to offer firm long term service using expansion facilities required for that purpose on the Nova System include the following provisions:

3.1 Posting of Expansion Capacity

If Company determines that demand for Service under Rate Schedule FT-D may be sufficient to consider expansion of existing Facilities ("Expansion Capacity"), Company shall provide Notice on the Website of the open season for such Expansion Capacity (the "Expansion Capacity Open Season"). At least 3 Banking Days after such Notice (excluding statutory holidays in the United States), Company shall post on the Website:

(a) the date such Expansion Capacity may be available; and

(b) the closing date for such Expansion Capacity Open Season (the "Expansion Closing Date").

3.2 Expansion Capacity Bid Process

If Company posts Expansion Capacity pursuant to Paragraph 3.1, prospective customers may bid for such Expansion Capacity, on any Banking Day up to and including the Expansion Closing Date, as follows:

(a) Prospective customers shall submit a completed and unedited Open Season Bid Form set out in article 6.0;

(b) The requested term of Service, as established by the Service Commencement Date and the requested Service Termination Date, each set out in the Open Season Bid Form, shall be a minimum term of 8 years;

(c) All bids shall be irrevocable and must be received by Company by 11:00 hours CCT on the Expansion Closing Date;

(d) Within 2 Banking Days of the Expansion Closing Date, prospective customers, except those who are also Customers receiving Service, other than Service under Rate Schedule IT-S or Rate Schedule FT-X, shall provide to Company for each Open Season Bid Form, a deposit equal to the lesser of:

(i) one month demand charges for the Delivery Contract Demand set out on the Open Season Bid Form; or

(ii) $10,000.

The deposit, if provided, shall be refunded to unsuccessful bidders within 5 Banking Days from the date the Service Agreements and Schedules of Service under Rate Schedule FT-D are executed for all Expansion Capacity posted in the Expansion Capacity Open Season.

…

3.4 Awarding of Expansion Capacity

Subject to paragraphs 3.3 and 3.5, Expansion Capacity shall be awarded to the prospective customers whose bids are accepted by Company as follows:

(a) Company shall rank the bids in descending priority on the basis of the per unit product of the current FT-D Demand Rate multiplied by the requested term (where the bid with the highest per unit product shall have the higher priority);

…

Response:

PNG confirms that the above referenced provisions are included in NOVA Gas Transmission Ltd.'s tariff on file with the NEB.

(4) Reference: *Canadian Mainline Gas Transportation Tariff*, *General Terms and Conditions* "Transportation Access Procedure" (January 1, 2015) at sections 4 & 5, online: http://www.tccustomerexpress.com/docs/ml_regulatory_tariff/04_Transportation_Access_Procedure.pdf

9.8 Having regard to Reference (4) above, please confirm that the terms and conditions that the National Energy Board (NEB) has authorized TransCanada PipeLines Ltd. (TransCanada) to offer firm long term service using existing capacity on the TransCanada Mainline System include the following provisions:

4.1 Posting of Existing Capacity

If at any time prior to or during an open season TransCanada determines it has Existing Capacity, TransCanada may at any time, notify Service Applicants and prospective Service Applicants by posting a Notice of:

(a) the Existing Capacity for each of the available System Segments;

(b) the Date of Commencement for such Existing Capacity, provided that TransCanada is not obligated to offer a Date of Commencement two (2) or more years from the date of the notice. In the case of MFP, the Date of Commencement shall occur within the MFP Commencement Period;

(c) the type of service available;

(d) in the case of FT-NR the term the service will be available for;

(e) in the case of MFP, the MFP Blocks and System Segments that TransCanada determines may be available, if any; and

(f) the date(s) the ECOS will commence and end.

4.2 The Existing Capacity Open Season

(a) TransCanada shall hold an open season for the Existing Capacity ("ECOS") commencing on or about July 15 in each calendar year (unless it has no Existing Capacity). The ECOS shall be for a period of time determined by TransCanada which shall not be less than two (2) full Banking Days after the commencement of such ECOS. TransCanada may hold an additional ECOS at any time it determines necessary. Service Applicant may during the ECOS submit by fax or mail or by electronic means an ECOS Bid Form for all or a portion of the Existing Capacity for a minimum term of one (1) year consisting of twelve (12) consecutive months. The date of commencement shall, subject to sub-section 3.2 of the MFP Toll Schedule and sub-section 10.3(b)(i) of the FT Toll Schedule, be the first day of the

month provided however, Service Applicant may specify a date of commencement other than the first day of the month, for the same month in which the Service Applicant submits an ECOS Bid Form ("Partial Month"). The service termination date shall, subject to sub-section 4.2(a)(iii), sub-section 3.2 of the MFP Toll Schedule and sub-section 10.3(b)(ii) of the FT Toll Schedule, be the last day of the month.

…

4.4 Allocation of Existing Capacity

(a) At the close of the ECOS, TransCanada shall rank the submitted ECOS Bid Forms and TransCanada shall, subject to sub-Section 4.4(b), allocate the Existing Capacity among Service Applicants in the following priority:

(i) First by the demand toll multiplied by the Contract term for each ECOS Bid Form or combination of ECOS Bid Forms, with the bid(s) yielding the highest overall product having the highest priority;

(I) If an ECOS Bid Form is for FT-SN, MFP or EMB Service, the applicable demand toll for the purpose of determining such product shall be the demand toll for FT Service from the receipt point to the delivery point or area each specified in the ECOS Bid Form;

(II) If an ECOS Bid Form is for service pursuant to the SNB Toll Schedule then the product of demand toll and Contract term will be adjusted by multiplying such product by the requested maximum capacity and dividing such amount by the actual impact on Posted Capacity as determined by TransCanada;

(ii) Then by the requested Date of Commencement, with the earliest requested Date of Commencement having the highest priority, provided that TransCanada will have no obligation to award any Existing Capacity to an ECOS Bid Form with a service to commence two or more years from the close of the ECOS.

Response:

PNG confirms that the above referenced provisions are included in TransCanada PipeLines Limited's tariff on file with the NEB.

9.9 Does PNG agree that under the provisions in the tariffs of each of the listed pipelines, it would have been required to conduct some variant of a non-discriminatory open season before committing capacity to an individual shipper for its current excess capacity and for any expansion capacity it required to serve a request for service?

Response:

PNG agrees that for each of the NEB regulated Group 1 gas transmission pipelines listed in the preceding questions, the pipeline's tariff provides that it conduct an open season and apply the approved tariff provisions prior to committing capacity to an individual shipper for such pipeline's current excess capacity and for any expansion capacity it required to serve a request for service.

PNG does not believe that its particular circumstances have warranted having or applying tariff provisions such as those quoted above. PNG is significantly different from the large NEB regulated Group 1 pipelines (consisting of those pipeline companies with extensive systems and several third-party shippers) that Western LNG has cited:

- PNG is primarily a distribution utility, serving over 42,000 end-use customers with natural gas. The pipelines noted by Western LNG do not have a utility function. On the PNG system the rates payable by certain shippers affect the delivered cost of natural gas to PNG's utility customers.

- PNG's existing uncontracted capacity has been available for almost thirteen years and its existence is well known in the Western Canadian gas market. It is not reasonable to suggest that having open season provisions in PNG's tariff would have changed that outcome. PNG believes that open seasons are intended to work on large pipeline systems which are connected to liquid markets, where multiple shippers can be accommodated, and with shippers who can evaluate their market requirements against market alternatives in a liquid market. PNG's pipeline system does not provide a circumstance where new shippers have the opportunity to connect to an existing market – such a market does not exist and must be developed by the shipper.

Potential projects in PNG's franchise area have consistently required significant capital costs on the part of the prospective shipper. Having an opportunity to reserve uncontracted capacity for a period of time until the project proponent can complete the development phase of its project is viewed to be the best approach to securing additional shippers on the PNG pipeline system for the following reasons:

- Individual negotiations with potential shippers, to verify creditworthiness and to coordinate project development with PNG's preparation of its system to provide transportation service, are more critical than the length of term commitment (which typically guides open season processes), given that uncontracted capacity may be fully taken up by a single shipper.

- The commitment to backstop engineering studies separates contracting parties who are not sufficiently advanced from parties that have sufficient confidence in their project to proceed to further development.

- Engineering studies are owned and conducted by PNG so as to retain control of the intellectual property and for the benefit of future projects if the contracting party does not proceed.

- The requirement for option payments for projects in the development phase guarantee a benefit to PNG's utility customers in the event that a contracting party is unable to successfully complete its project. This has been demonstrated under previous option arrangements for PNG's uncontracted capacity.

- The option payment mechanism sets a reasonable deadline and, in the event a project does not proceed, it ensures the agreement is terminated prior to PNG incurring any additional capital investment. Following termination, the capacity is then available for PNG to contract with other parties.

- The BCUC approval process also assures transparency and oversight to ensure that PNG's utility customers are treated fairly and that all transportation contracts are negotiated at arm's length.

9.10 Does PNG agree that open seasons can provide it with valuable information concerning the extent of demand for capacity on its system and the best means to optimize the pipeline to that demand, including consideration of what additional facilities may be needed to serve demand that exceeds current capacity?

Response:

As described in PNG's response to Question 9.9, PNG believes that its current process is the best means for PNG to optimize pipeline utilization for its customers. For many of the reasons cited in the response to Question 9.9, PNG does not believe that it would obtain binding commitments for firm transportation service from sufficiently creditworthy parties through an open season process.

9.11 Is PNG currently prepared to hold an open season in respect of the currently existing capacity on the pipeline--including the volumes in the Triton Letter Agreement?

Response:

For the reasons outlined in response to Question 9.9, PNG believes that its current process is the best means for PNG to optimize pipeline utilization for its customers.

9.12 If the Commission were to deny this application, would PNG be prepared to commit to holding an open season in connection with its existing and potential expansion capacity?

Response:

If the Commission were to deny this Application, PNG would evaluate its alternatives. For the reasons outlined in response to Question 9.9, PNG believes that its current process is the best means for PNG to optimize pipeline utilization for its existing customers. However, if PNG became aware of potential creditworthy shippers that were prepared to provide binding commitments for firm transportation service at non-discounted rates, an open season process would be considered.

10. Reference: Exhibit B-5, page 11, para 28.4.

"For the potential new customers, either an existing rate on a rate would be proposed, depending on the result of PNG's analyses."

10.1 Please confirm that the facilities to serve Triton's proposed 50 MMcf/day demand at Prince Rupert would not be required to serve up to 70 MMcf/day demand at Kitimat.

Response:

Not confirmed. PNG would require much of the existing pipeline and compression facilities to be recommissioned in either scenario, which would require an investment to refurbish and repair aging facilities. There would also be system integrity work required. PNG does note that the interconnecting pipeline to serve the Triton project and some upgrades downstream of Terrace would not be required. At the same time, another interconnecting pipeline would likely be required to serve up to 70 MMcf/day demand at Kitimat for another project.

10.2 Does PNG expect that the additional facilities needed for a 50 MMcf/day project to Prince Rupert would trigger the need for an environmental assessment?

Response:

PNG would comply with all of the environmental legislation for any pipeline and compression project, which would require environmental permitting. PNG does not expect that it would require an environmental assessment certificate under the BC *Environmental Assessment Act* for the case of 50 MMcf/day.

10.3 Please confirm that (assuming the Triton 50 MMcf/day demand proceeded), if any future shipper were to contract for capacity on the PNG system from Summit Lake to Kitimat in a volume that exceeded the remaining 30 MMcf/day on the mainline, an expansion of the mainline would be required. Would the expansion that would be required to serve such a shipper to fully utilize the 70 MMcf/day of capacity from Terrace to Kitimat require looping of the mainline and added compression between Summit Lake and Terrace to the extent that PNG would be required to file an environmental assessment under BC and/or Federal law? If PNG has done preliminary hydraulic studies to determine a rough scope of such an expansion, please summarize those findings.

Response:

For the scenario whereby PNG provides 50 MMcf/day (Triton) and 70 MMcfd/day (Western) at Kitimat, PNG would require the full reactivation and recommissioning of its existing pipeline system and compressor stations, including rebundling some if its existing compressors. Depending on the pipe size chosen, there would also be looping required downstream of the R1, R2, R3, R4 compressor stations (~160 km), as well as new compression facilities required at R5 (Terrace) and R6 (Salvus). There would also be interconnecting pipelines to each of the Western and Triton sites, which could vary in length.

PNG notes that an Environmental Assessment (EA) is triggered at 50 km of 12 inch pipeline, therefore, PNG would need to assess and determine if the fact that the pipeline looping is not all contiguous factors into the need for an EA. However, PNG believes that it is likely an EA is required for this scenario. PNG would also assess building a larger diameter pipeline to serve numerous customer requirements, as it could be short sighted to build only 12 inch looping, and restrict further growth on the system with small diameter pipeline. PNG also notes that expanding the existing system to accommodate volumes beyond 120 MMcf/d (50 MMcf/d for Triton and 70 MMcf/d for Western LNG) would involve a very difficult segment to bypass the Telkwa pass.

Further, as described in the response to Questions 8.2 and 9.12, PNG's expansion capacity on the mainline portion between Summit Lake and Terrace would need careful consideration from a system design perspective, considering existing and future growth requirements.

(i) In the above scenario, would Triton's rate be adjusted to reflect Triton's share of the mainline expansion, or would the entire cost of the mainline expansion be shouldered by the new customer that sought to utilize the capacity from Summit Lake to Kitimat?

Response:

PNG submits that expanding the PNG system beyond its original design has broad implications to all classes of customers on its system and would need to be fully considered. PNG notes that its proposal to Triton on the total capacity requested would take into consideration the entire cost of the mainline, including expansion costs.

11. Reference: Exhibit B-2, page 6, response to BCUC IR 1.7

"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*." (emphasis added)

11.1 In the referenced response, PNG provides a tabular and graphical representation that shows "Prince Rupert Capacity" for 2017. Please provide similar tabular and graphical representations that shows pipeline capacity, existing firm demand, interruptible demand and available excess capacity on each of the following three segments on an annual basis for each of 2014 to 2017:

(a) Summit Lake to Terrace;

(b) Terrace to Kitimat; and

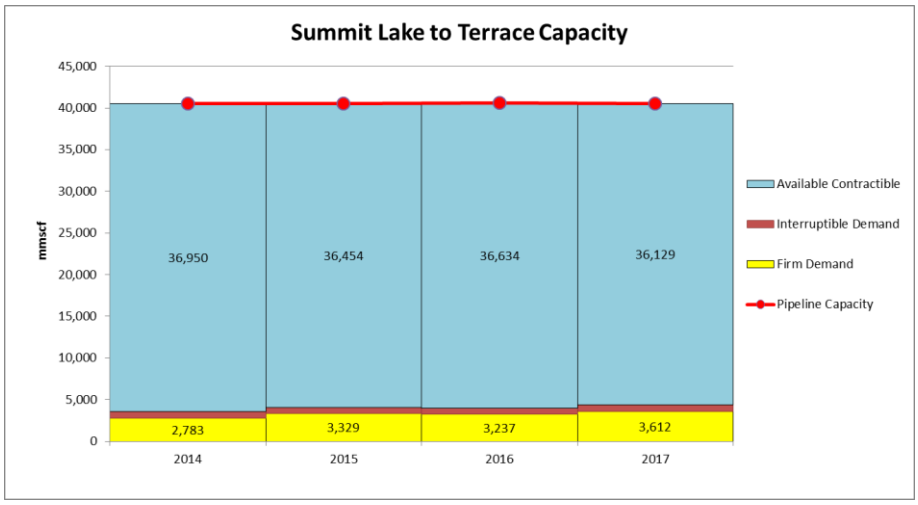
(c) Terrace to Prince Rupert.

Response:

Please see the following tables and charts for capacity on each of the requested segments. PNG has provided the capacity for each segment below based on the assumption that all existing assets are reactivated and recommissioned. As requested, on the pages that follow, PNG has provided the available capacity in aggregate on an annual basis and notes that it is not representative of the daily available capacity.

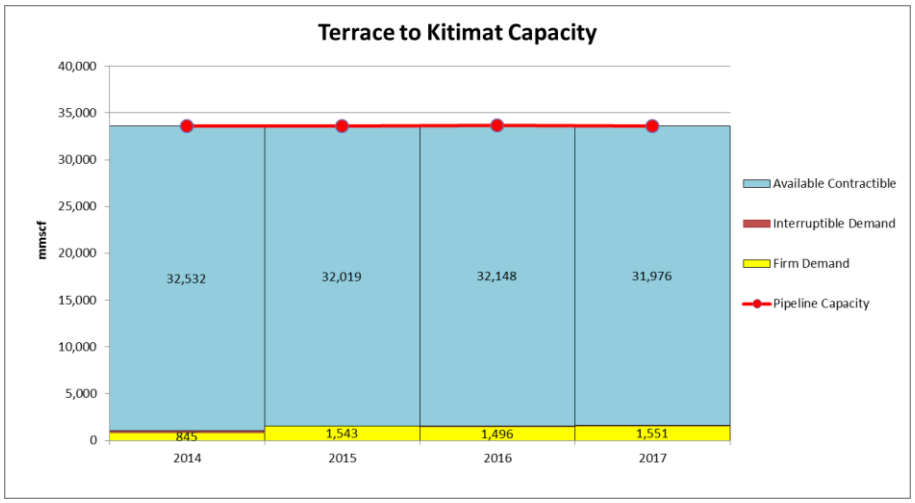
(a) Summit Lake to Terrace:

	mmscf			
	2014	2015	2016	2017
Firm Demand	2,783	3,329	3,237	3,612
Interruptible Demand	782	732	755	774
Available Contractible	36,950	36,454	36,634	36,129
Pipeline Capacity	40,515	40,515	40,626	40,515



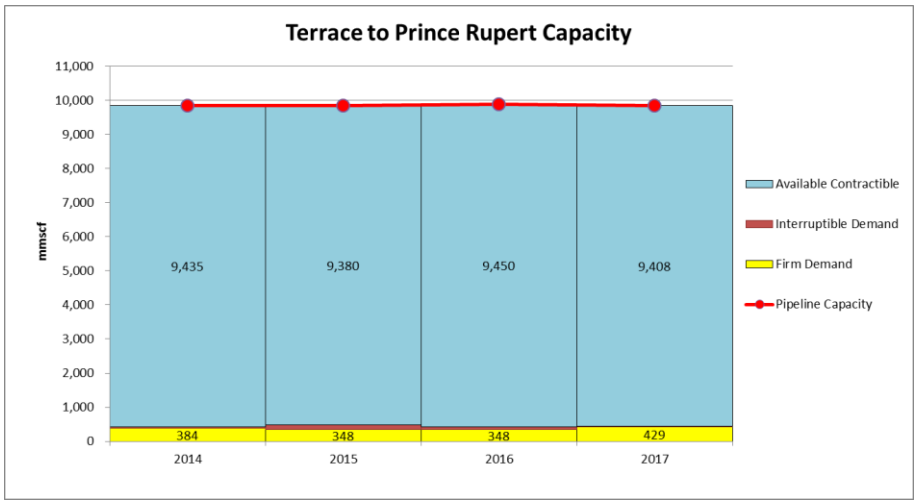
(b) Terrace to Kitimat:

	mmscf			
	2014	2015	2016	2017
Firm Demand	845	1,543	1,496	1,551
Interruptible Demand	203	17	27	53
Available Contractible	32,532	32,019	32,148	31,976
Pipeline Capacity	33,580	33,580	33,672	33,580



(c) Terrace to Prince Rupert:

	mmscf			
	2014	2015	2016	2017
Firm Demand	384	348	348	429
Interruptible Demand	36	127	84	18
Available Contractible	9,435	9,380	9,450	9,408
Pipeline Capacity	9,855	9,855	9,882	9,855



11.2 Please prepare an alternate graphic for each pipeline of these three segments for each of the following scenarios:

(a) Triton exercises the option for 20 MMcf/day;

(b) Triton exercises the option for 50 MMcf/day;

(c) Triton does not exercise either option, but a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat;

(d) Triton exercises only its option for the baseline 20 MMcf/day contemplated under the Letter Agreement and a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat

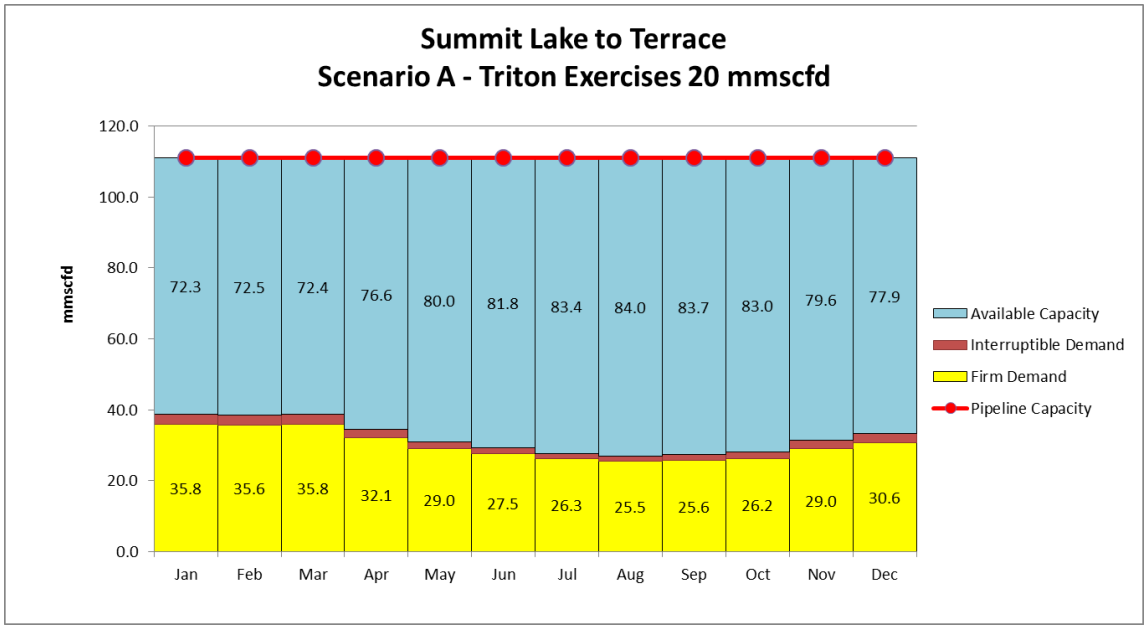
(e) Triton exercises its option for the additional 30 MMcf/day (for a total of 50 MMcf/day) and a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat.

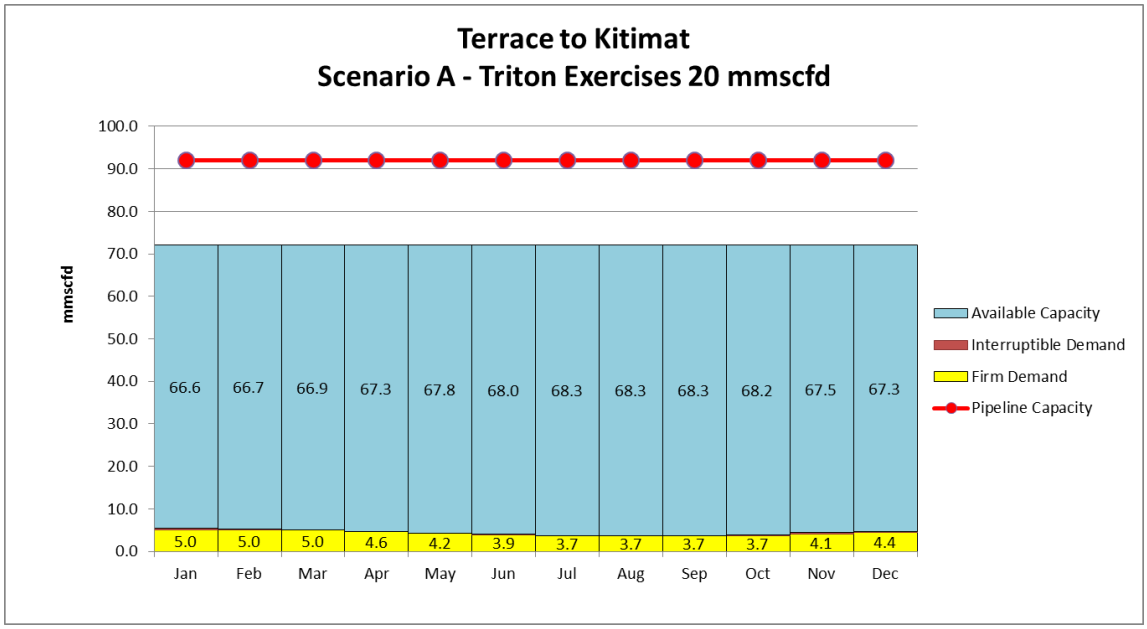
Response:

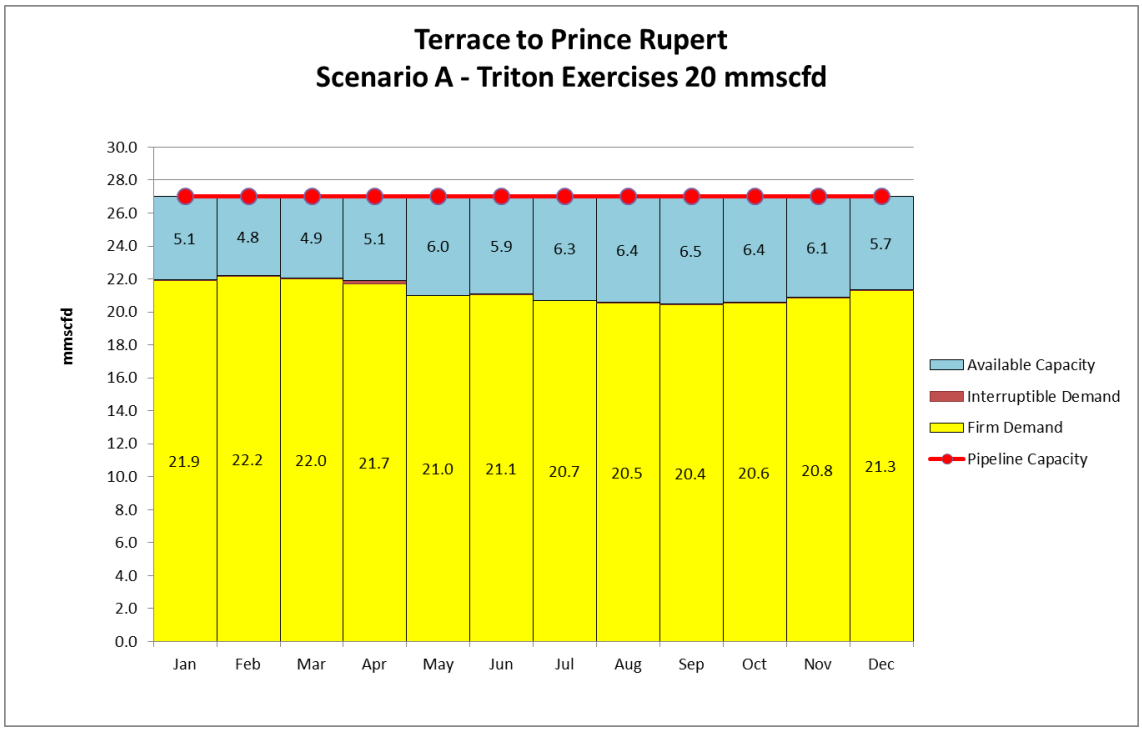
PNG has provided the graphical representations below on each segment based on 2017 actual data and the assumption that all existing assets are reactivated and recommissioned, along with the addition of required new assets (which may require significant capital) to meet the loads under each of the scenarios.

However, PNG notes that the exact design of new assets incorporated into the analysis underlying the graphs is illustrative only and would depend on the overall system design considering PNG's existing and long-term requirements. PNG also notes that there are other system considerations for any detailed design, including system pressure, operational flexibility, compressor fuel and future demand. Finally, PNG notes that its hydraulic model has not been "tuned" for high volumetric flows (as the system has not run at full capacity for many years), and could contain possible forecast inaccuracies (i.e. within 5%).

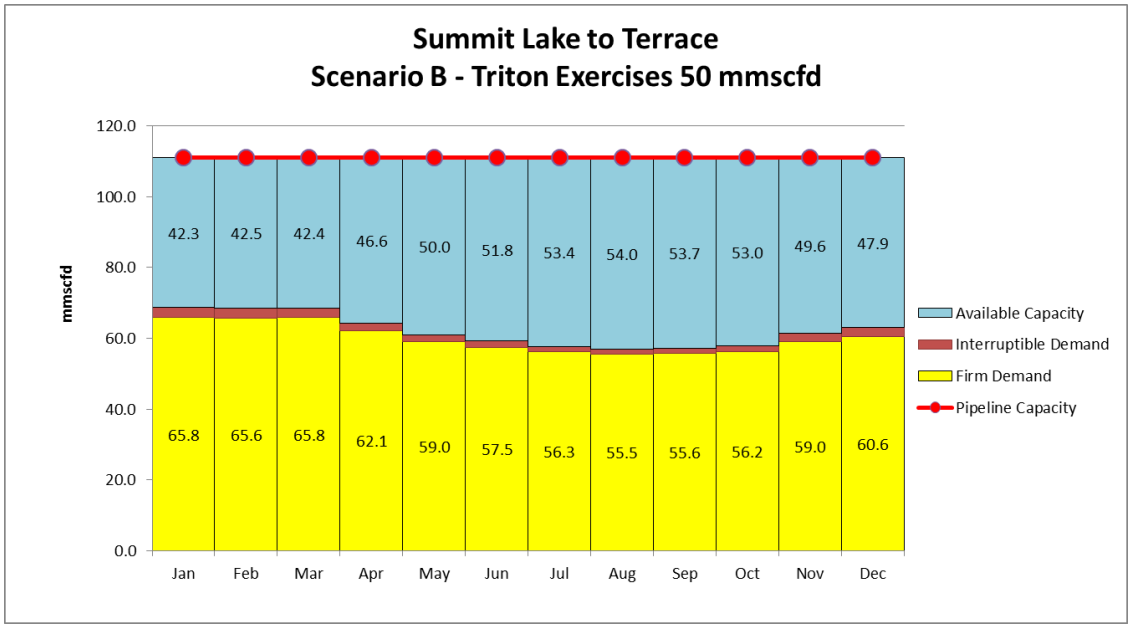
(a) Triton exercises the option for 20 MMcf/day

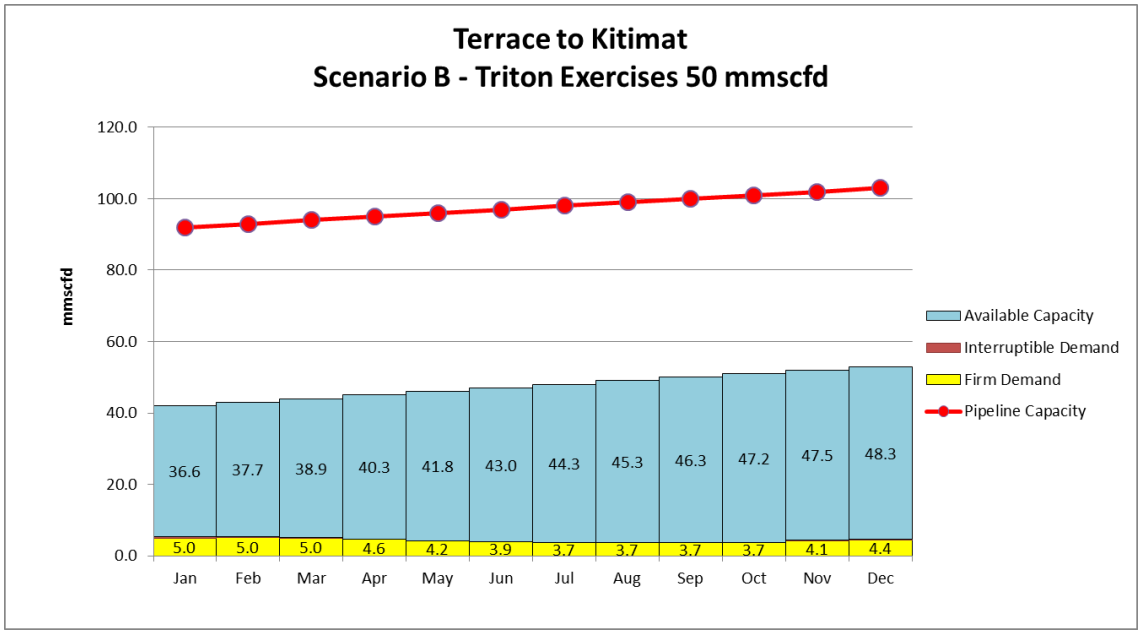


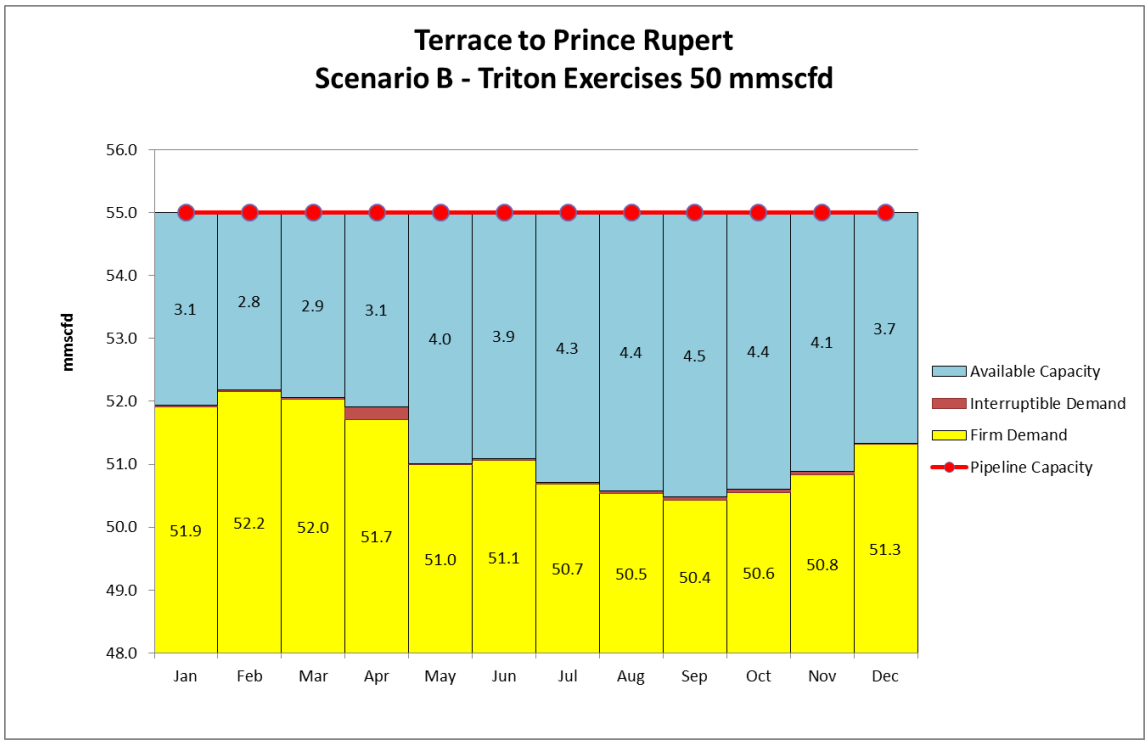



Terrace to Prince Rupert
Scenario A - Triton Exercises 20 mmscfd
mmscfd
30.0
28.0
26.0
24.0
22.0
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
5.1
4.8
4.9
5.1
6.0
5.9
6.3
6.4
6.5
6.4
6.1
5.7
21.9
22.2
22.0
21.7
21.0
21.1
20.7
20.5
20.4
20.6
20.8
21.3
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Available Capacity
Interruptible Demand
Firm Demand
Pipeline Capacity

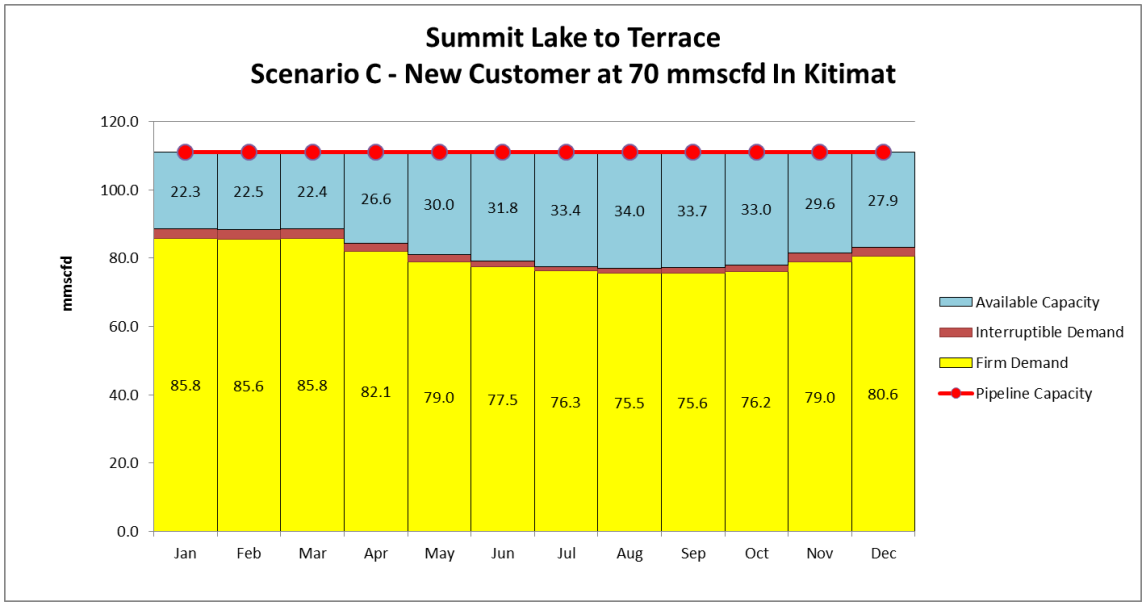
(b) Triton exercises the option for 50 MMcf/ day

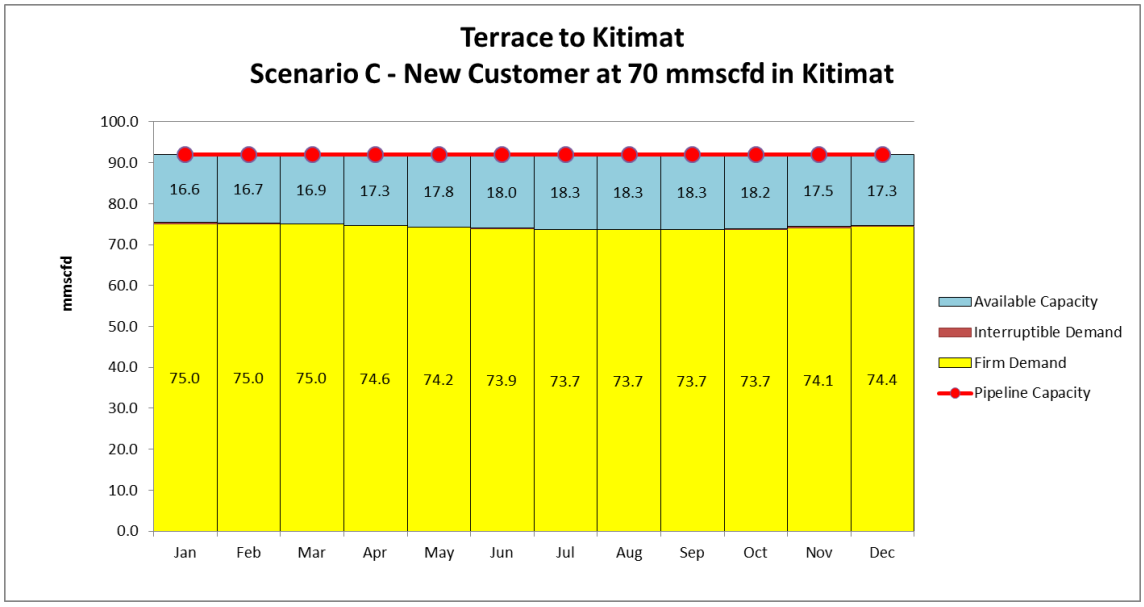


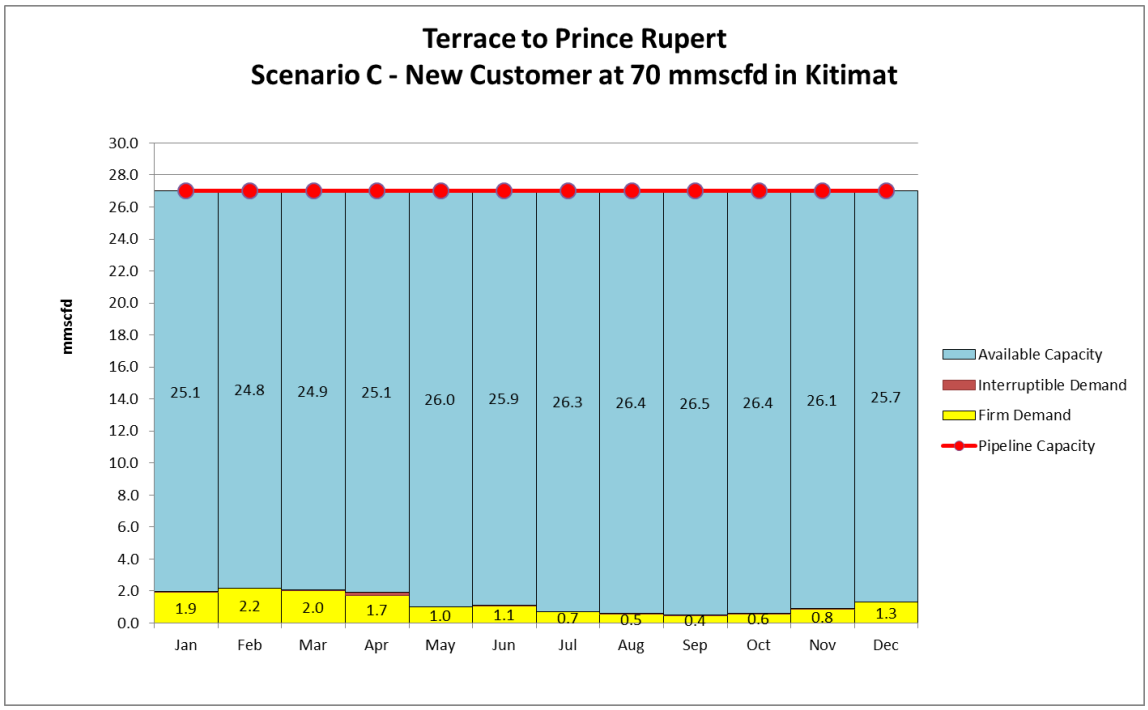



Terrace to Prince Rupert
Scenario B - Triton Exercises 50 mmscfd
mmscfd
56.0
55.0
54.0
53.0
52.0
51.0
50.0
49.0
48.0
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
3.1
2.8
2.9
3.1
4.0
3.9
4.3
4.4
4.5
4.4
4.1
3.7
51.9
52.2
52.0
51.7
51.0
51.1
50.7
50.5
50.4
50.6
50.8
51.3
Available Capacity
Interruptible Demand
Firm Demand
Pipeline Capacity

(c) Triton does not exercise either option, but a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat






Terrace to Prince Rupert
Scenario C - New Customer at 70 mmscfd in Kitimat
mmscfd
30.0
28.0
26.0
24.0
22.0
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
25.1
24.8
24.9
25.1
26.0
25.9
26.3
26.4
26.5
26.4
26.1
25.7
1.9
2.2
2.0
1.7
1.0
1.1
0.7
0.5
0.4
0.6
0.8
1.3
Jan
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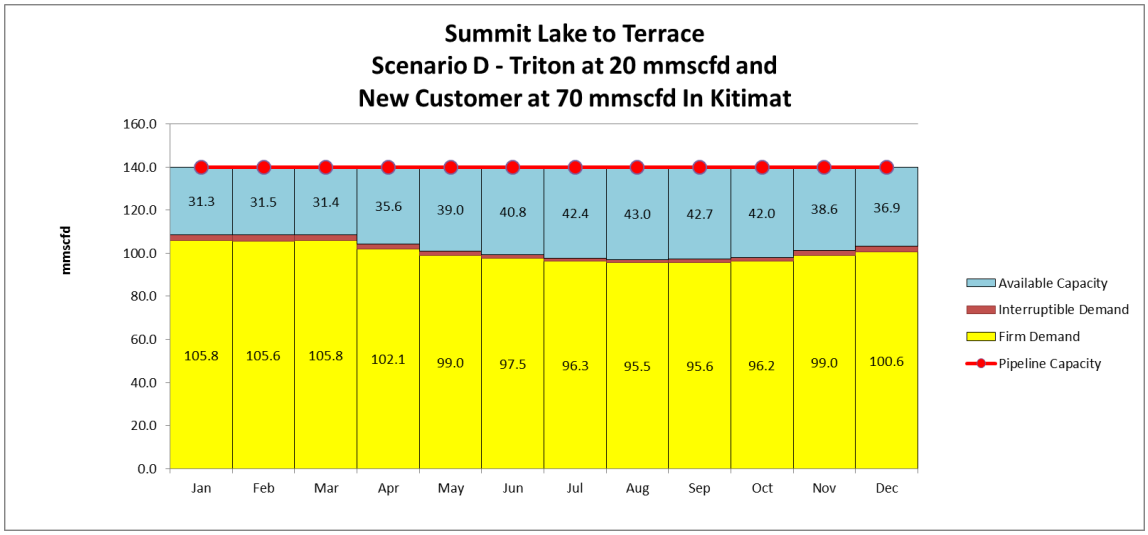
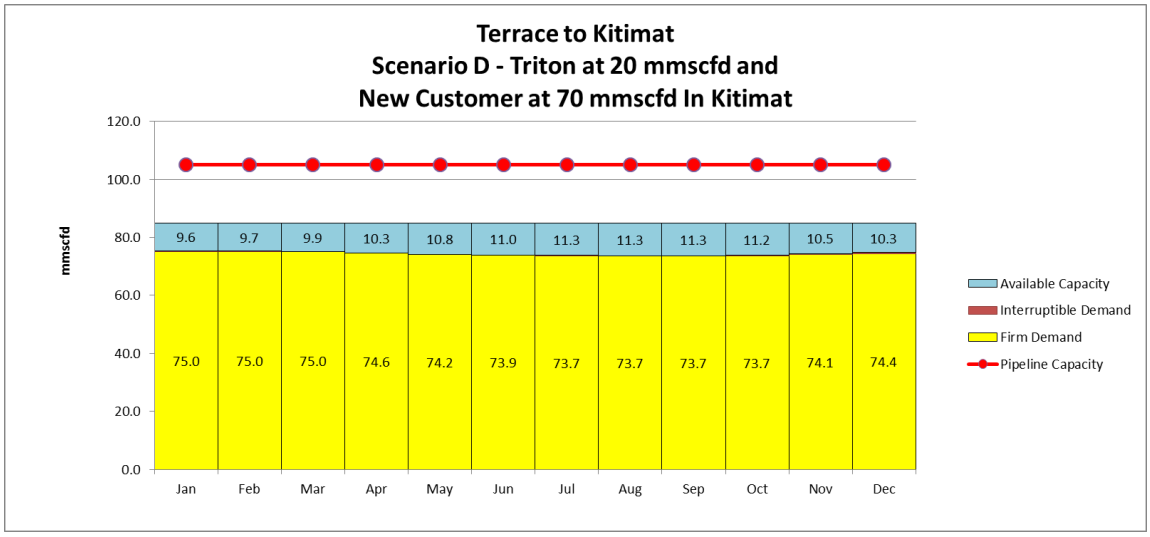
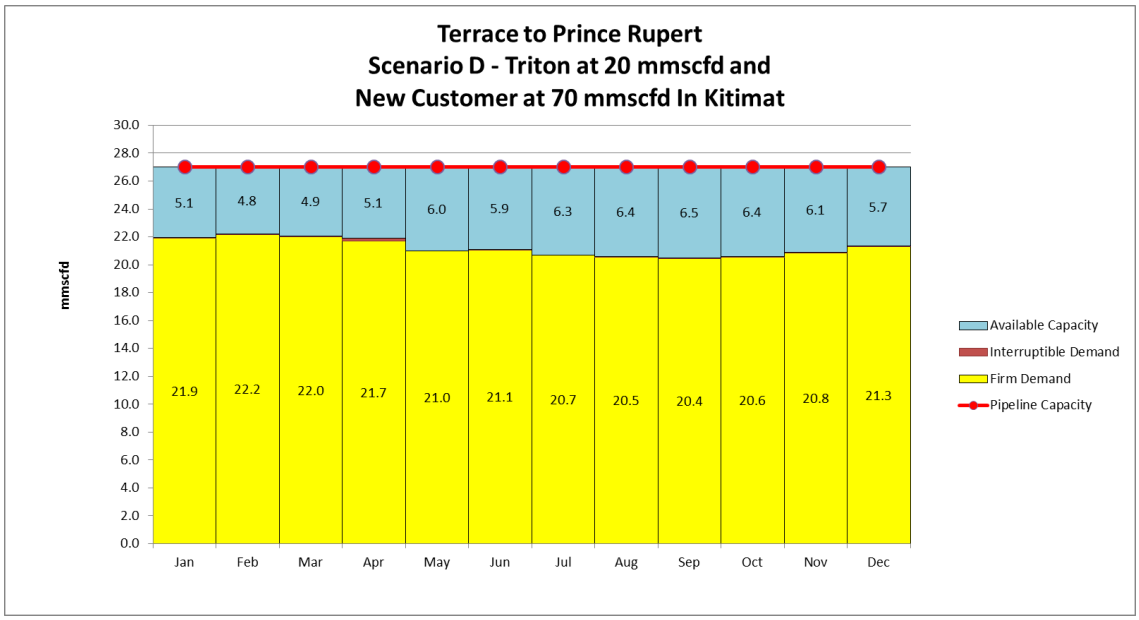
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Available Capacity
Interruptible Demand
Firm Demand
Pipeline Capacity

(d) Triton exercises only its option for the baseline 20 MMcf/day contemplated under the Letter Agreement and a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat






Terrace to Prince Rupert
Scenario D - Triton at 20 mmscfd and
New Customer at 70 mmscfd In Kitimat
mmscfd
30.0
28.0
26.0
24.0
22.0
20.0
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
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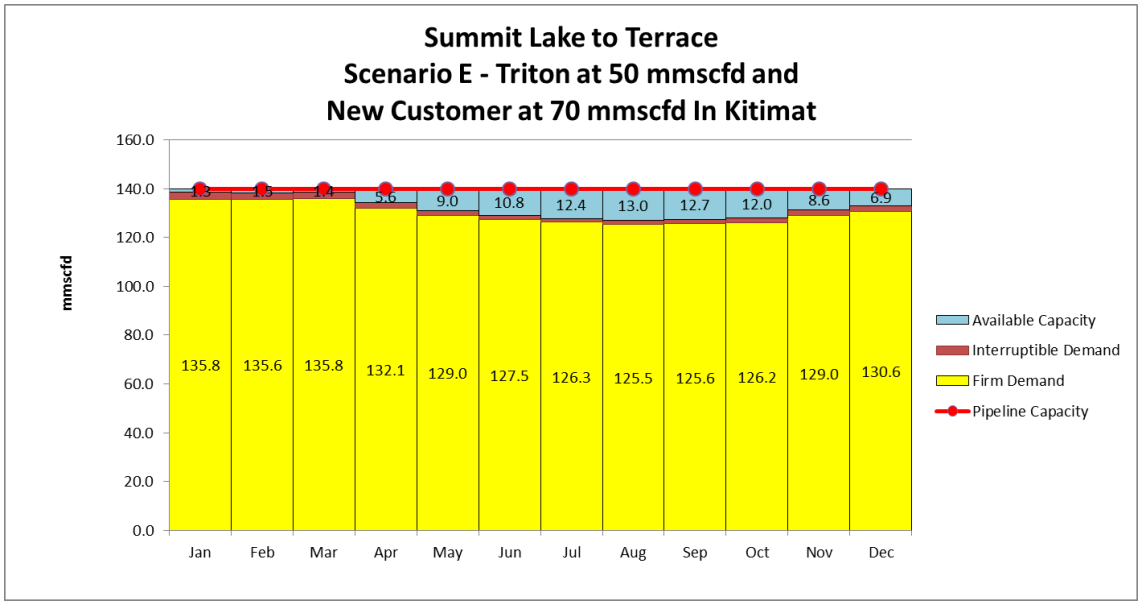
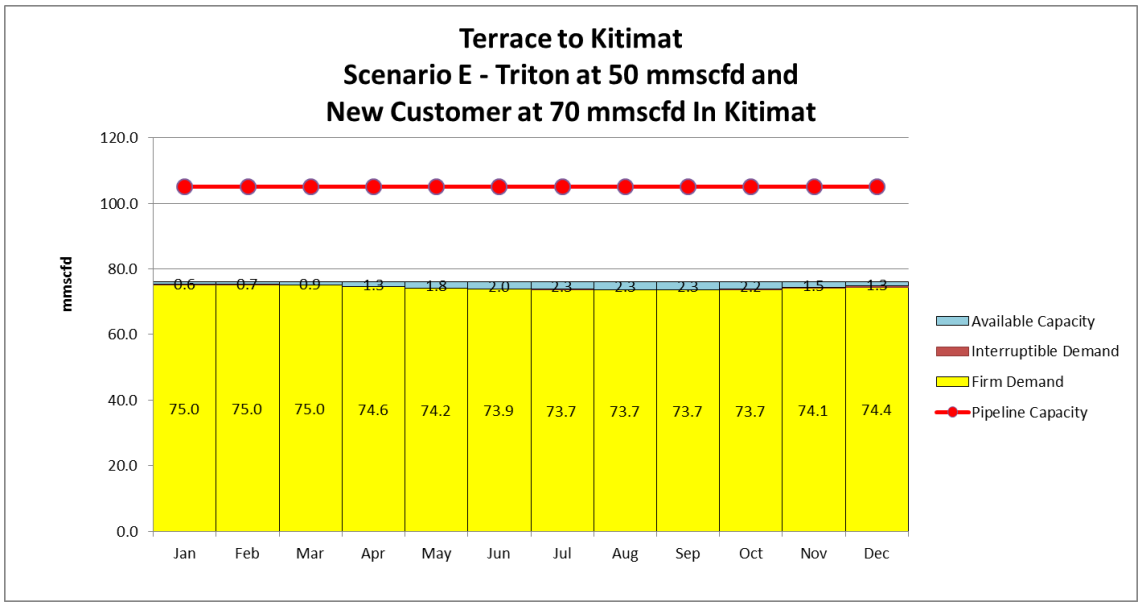
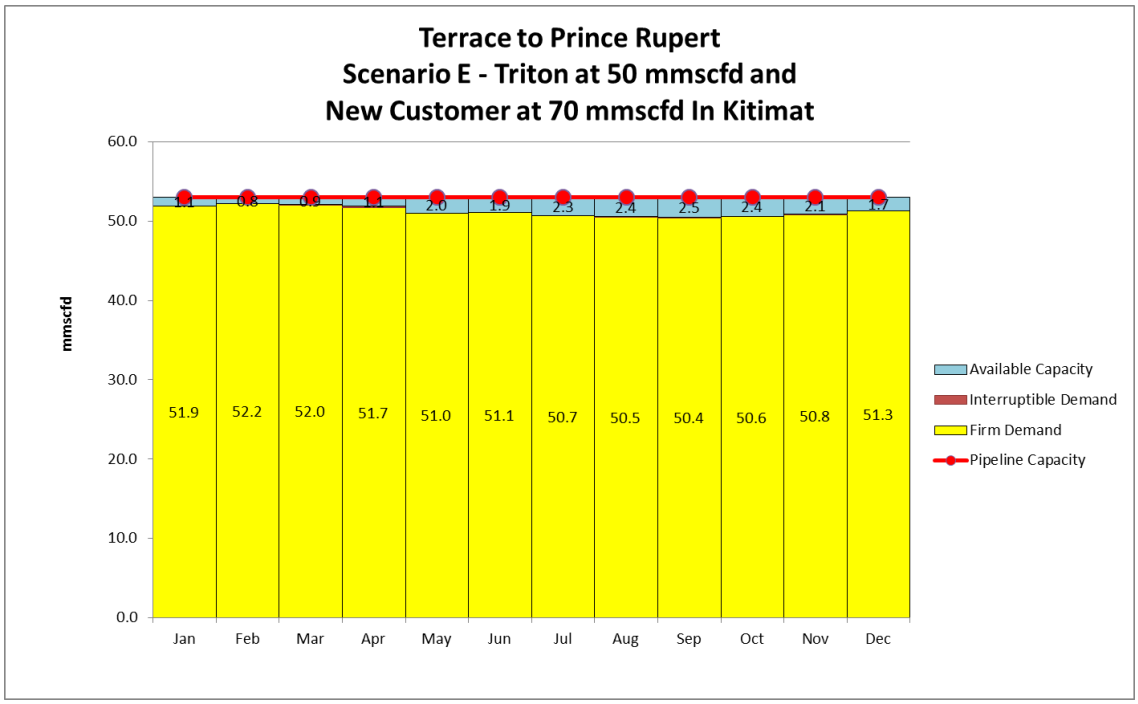
Nov
Dec
5.1
4.8
4.9
5.1
6.0
5.9
6.3
6.4
6.5
6.4
6.1
5.7
21.9
22.2
22.0
21.7
21.0
21.1
20.7
20.5
20.4
20.6
20.8
21.3
Available Capacity
Interruptible Demand
Firm Demand
Pipeline Capacity

(e) Triton exercises its option for the additional 30 MMcf/day (for a total of 50 MMcf/day) and a new customer enters into an agreement for firm service of 70 MMcf/day in Kitimat






Terrace to Prince Rupert
Scenario E - Triton at 50 mmscfd and
New Customer at 70 mmscfd In Kitimat
mmscfd
60.0
50.0
40.0
30.0
20.0
10.0
0.0
1.1
0.8
0.9
1.1
2.0
1.9
2.3
2.4
2.5
2.4
2.1
1.7
51.9
52.2
52.0
51.7
51.0
51.1
50.7
50.5
50.4
50.6
50.8
51.3
Jan
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Nov
Dec
Available Capacity
Interruptible Demand
Firm Demand
Pipeline Capacity

12. Reference: Exhibit B-1, page 3 of 8.

"Triton will have 30 days to either accept or reject PNG's proposal for such Expanded Capacity."

Reference: Appendix A - Letter Agreement between PNG and Triton, Clauses 5(e), (i) and (j), pages 3 and 4.

"Within 5 business days of payment of the Initial Option Fee to PNG[…], Triton shall provide PNG with written notice either accepting or rejecting the Expanded Capacity Notice…"

12.1 Does Triton have 30 days or 5 days to exercise its option for the expanded capacity?

Response:

Triton must provide a written notice accepting or rejecting PNG's Expanded Capacity notice within five business days of payment of the Initial Option Fee. The Escrow Agent will pay the Initial Option Fee to PNG upon the later of: (i) date of Commission approval with no conditions; (ii) fifteen days after the Commission approval date with conditions that are acceptable to the parties; and (iii) date which PNG issues the Expanded Capacity Notice.

12.2 Pursuant to clauses 5(i) and (j), please confirm that Triton has up to two and a half (2.5) years (consisting of the "12 months following the date on which the Initial Option Fee is paid" and "three separate options to extend the Option Period by six months each") to provide PNG written notice of commencement of Service under the Transportation Agreement.

Response:

Confirmed.

12.3 Pursuant to clauses 5(i) and (j), please confirm that, if the above notice is given (up to 2.5 years into the Option Period), it can provide for commencement of service on a date up to three (3) years following the date of such notice.

Response:

Confirmed.

13. Reference: Exhibit B-5, page 11, para. 30

"Triton is not, however, an 'affiliate' of PNG under the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44."

13.1 Please confirm that Pacific Northern Gas Ltd. is a corporation incorporated or established under the laws of British Columbia.

Response:

Confirmed.

13.2 Please confirm that Triton LNG Limited Partnership is a partnership formed under the laws of Alberta and registered to do business in British Columbia.

Response:

Confirmed.

13.3 Please confirm that the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44 (section 2(1) and 2(2)(a) defines "affiliate" as "one body corporate" which "is affiliated with another body corporate."

Response:

Section 2(1) of the *Canada Business Corporations Act* defines "affiliate" as "an affiliated body corporate within the meaning of subsection (2)". Section 2(2) provides: "For the purposes of this Act, (a) one body corporate is affiliated with another body corporate if one of them is the subsidiary of the other or both are subsidiaries of the same body corporate or each of them is controlled by the same person; and (b) if two bodies corporate are affiliated with the same body corporate at the same time, they are deemed to be affiliated with each other."

13.4 Please confirm that Triton LNG Limited Partnership, being a "partnership" is not a "body corporate" under the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44.

Response:

Confirmed.

13.5 Please confirm that AltaGas Ltd. (a partner in Triton) is, when acting on behalf of the partnership, an "associate" of Triton under the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44.

Response:

Not Confirmed. Triton LNG Limited Partnership is a limited partnership between Triton LNG Inc. (General Partner) and AltaGas Idemitsu Joint Venture Limited Partnership (Limited Partner). While AltaGas Ltd. does not have a controlling interest in Triton LNG and would not fall within the strict definition of an "associate" as that term is defined in the *Canada Business Corporations Act*, PNG recognizes that AltaGas Ltd. has a significant indirect interest in Triton LNG.

Recognizing the relationship between PNG and AltaGas Ltd., PNG was careful to deal with Triton LNG in an arm's length manner and to craft an agreement that was, in its view, in the best interests of PNG's underutilized system. Furthermore, both PNG and Triton LNG understood and acknowledged that the Letter Agreement would be subject to Commission scrutiny and approval and therefore were cognizant of the need to ensure the Letter Agreement included appropriate terms that were consistent with previous option agreements approved by the Commission.

13.6 Please confirm that Pacific Northern Gas Ltd. is a subsidiary of AltaGas Ltd.

Response:

Confirmed. Pacific Northern Gas Ltd. is 100% owned by AltaGas Utility Holdings (Pacific) Inc., which in turn is 100% owned by AltaGas Ltd.

13.7 Please confirm that Pacific Northern Gas Ltd. is an "affiliate" of AltaGas Ltd. under the *Canada Business Corporations Act*, R.S.C. 1985, c. C-44 (section 2(2)(a) of which states: "one body corporate is affiliated with another body corporate if one of them is the subsidiary of the other…").

Response:

Confirmed. PNG is an affiliate of AltaGas Ltd. by virtue of being either a subsidiary of AltaGas Ltd. (per response to Question 13.6) or a subsidiary of a subsidiary of AltaGas Utility Holdings (Pacific) Inc. Under s.2(5) of the *Canada Business Corporations Act*: "A body corporate is a subsidiary of another body corporate if (a) it is controlled by (i) that other body corporate... or (b) it is a subsidiary of a body corporate that is a subsidiary of that other body corporate."

13.8 Please confirm that (i) as an Affiliated Provider, AltaGas is subject to the *Code of Conduct Regulation* (Alberta Regulation 58/2015); and (ii) pursuant to section 2(2) of the *Code of Conduct Regulation*, a retailer is an "affiliate" if it:

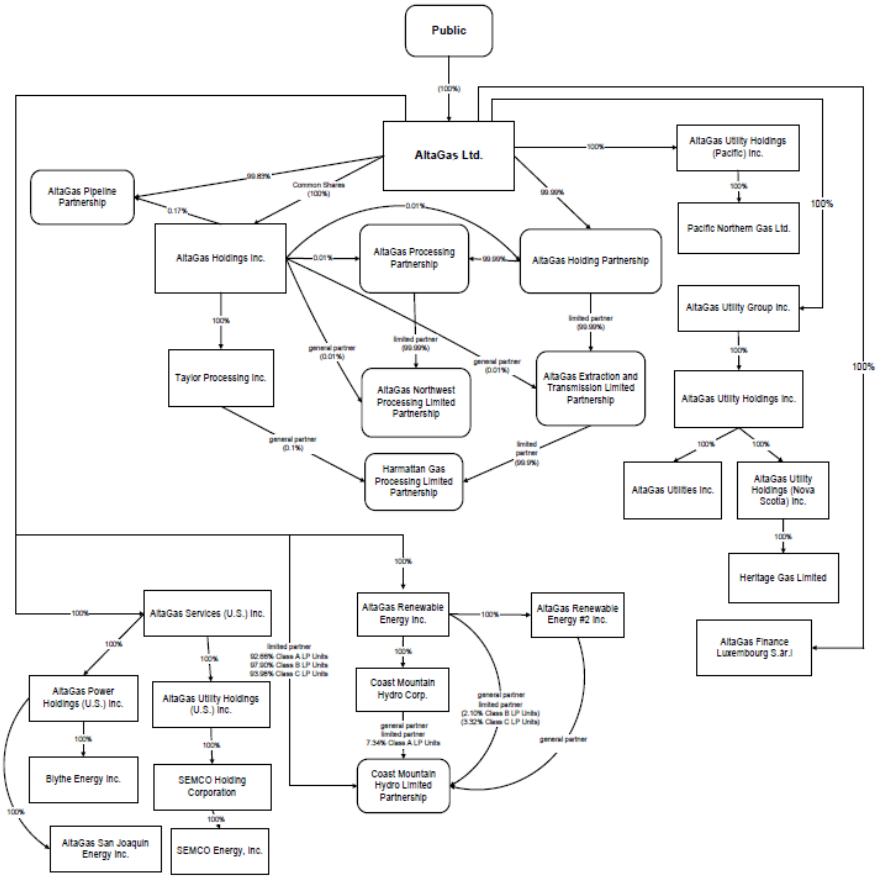
(i) is a corporation of which the owner …legally or beneficially owns or controls, directly or indirectly…at least 10% of the voting shares…

(iii) is in a partnership with the owner … including, without limitation, a general partner of a limited partnership…

Response:

Confirmed. The *Code of Conduct Regulation* Alberta Regulation 58/2015 governs the relationship between a gas distribution utility and an affiliate that provides retail gas services in relation to that gas distributor's system. Given that AltaGas Ltd. is an affiliate gas retailer of AltaGas Utilities Inc. and indirectly owns at least 10% of the voting shares of AltaGas Utilities Inc., it is an "affiliated provider" under the regulation.

13.9 Please confirm the following is a copy of AltaGas Ltd.'s corporate organizational structure as at December 31, 2016.[1] If available, please produce an up to date version of the organizational structure.

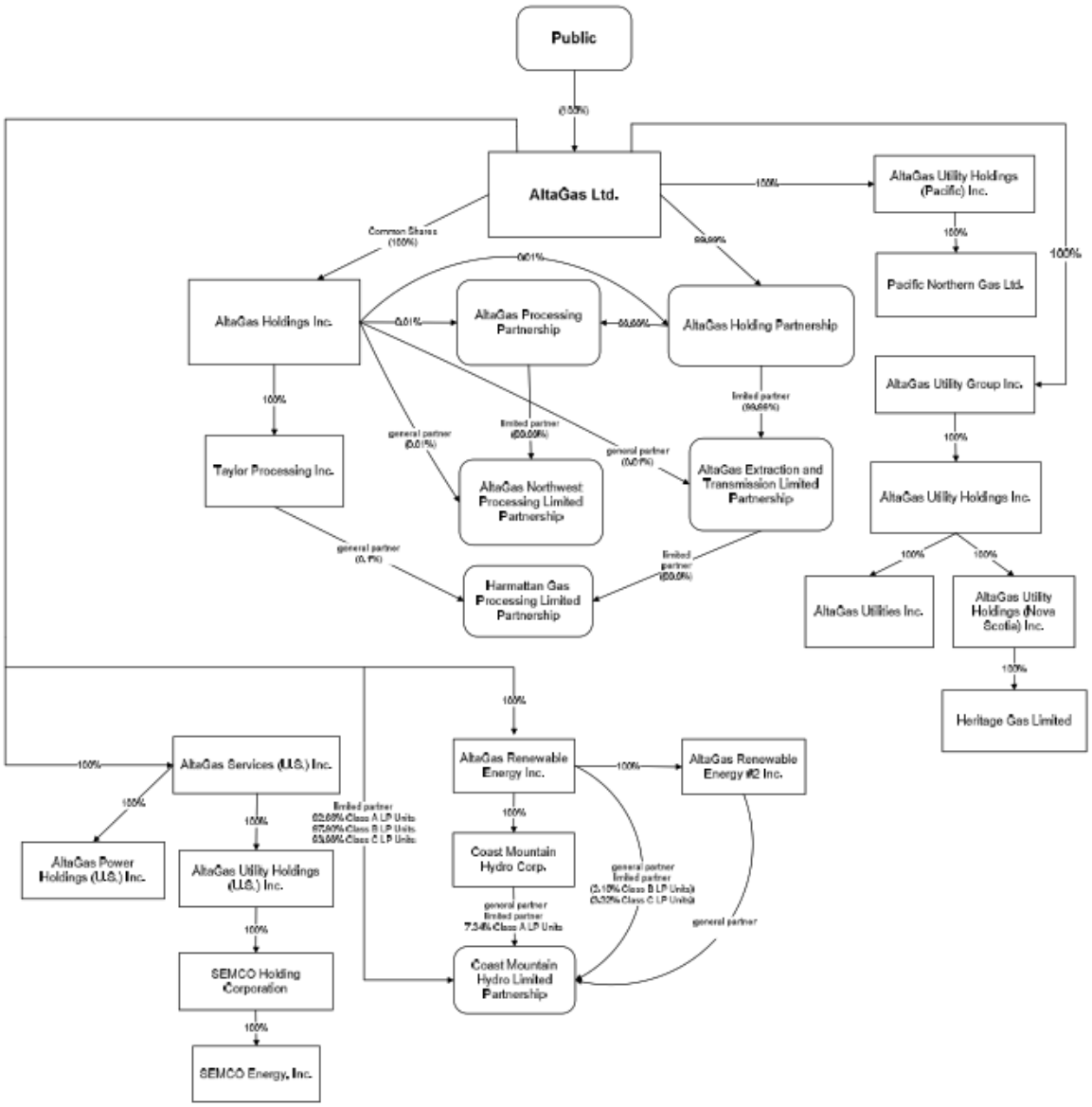


Response:

PNG can confirm that the corporate organizational structure is consistent with the organizational chart included in AltaGas Ltd.'s Annual Information Form for the year ending December 31, 2016.

The organizational structure that was included in the Annual Information Form filed on SEDAR for the year ending December 31, 2017 is reproduced on the page that follows.

[1] AltaGas Utilities Inc., *Inter-Affiliate Code of Conduct 2016 Compliance Report* (April 28, 2017) at page 3, online: <http://www.altagasutilities.com/sites/default/files/2005-01-05-AUI-EUB-Approved-Inter-Affiliate-Code-of-Conduct.pdf >



Note:

(1) Each of AltaGas Ltd., AltaGas Holdings Inc., AltaGas Utility Holdings (Pacific) Inc., AltaGas Utility Group Inc., AltaGas Utility Holdings Inc., AltaGas Utilities Inc., and Heritage Gas Limited is a corporation incorporated or formed by amalgamation or continuance under the CBCA. Each of AltaGas Utility Holdings (Nova Scotia) Inc., Taylor Processing Inc., AltaGas Processing Partnership, AltaGas Northwest Processing Limited Partnership, AltaGas Extraction and Transmission Limited Partnership and Harmattan Gas Processing Limited Partnership is a corporation, partnership or limited partnership (as applicable) incorporated, formed or established under the laws of Alberta. Each of AltaGas Renewable Energy Inc., AltaGas Renewable Energy #2 Inc., Coast Mountain Hydro Corp., Pacific Northern Gas Ltd. and Coast Mountain Hydro Limited Partnership is a corporation or limited partnership (as applicable) incorporated, formed or established under the laws of British Columbia. Each of AltaGas Services (U.S.) Inc., AltaGas Utility Holdings (U.S.) Inc., SEMCO Holding Corporation, and AltaGas Power Holdings (U.S.) Inc. is a corporation formed under the laws of Delaware. AltaGas Holding Partnership is a partnership formed or established under the laws of Ontario and SEMCO Energy, Inc. is a corporation formed under the laws of Michigan.

14. Reference: Exhibit B-5, page 11, para. 32; Code of Conduct

"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."

Page 2 of the Code of Conduct[2]: "This Code of Conduct (COC) governs the provision by Pacific Northern Gas Ltd. (PNG), a utility regulated by the British Columbia Utilities Commission (Commission), of utility resources and services to PNG's non-regulated businesses and affiliates (for ease of reference, jointly referred to herein as NRBs). This COC applies to the conduct of PNG's wholly-owned subsidiary Pacific Northern Gas (N.E.) Ltd. [PNG(N.E.)], also a utility regulated by the Commission."

14.1 What portions of the Code of Conduct, if any, as approved by the Commission in 2012, were intended to govern the relationship between PNG and its corporate parent seeking service on PNG?

Response:

As noted, PNG's most recent Code of Conduct (COC) and Transfer Pricing Policy (TPP), both dated November 2011, were approved by the Commission in 2012. The COC and TPP were prepared in consideration of the Commission's Retail Market Downstream of the Utility Meter (RMDM) Guidelines and primarily to address matters regarding non-regulated business (NRB) activities and govern the provision of utility resources and services to PNG's non-regulated businesses and affiliates (collectively referred to as NRBs in the COC). [Emphasis added]

In the context of the Triton Project, AltaGas, one of the joint venture partners on the project, would be considered an affiliate of PNG. And while the COC and TPP are structured to address NRBs and RMDM matters, as noted in response to BCUC IR 1.2.1.1 (Exhibit B-3), PNG is very cognizant of its relationship with its parent company and the principles and spirit of its COC has guided PNG's conduct as it pertains to the Triton Project. In particular, the following sections of COC are considered to be relevant:

Section 2. Price for Provision of Utility Resources and Services

- PNG has complied with acceptable business practices in its negotiations to provide service to the Triton Project under terms similar to those that would be made available to any party with similar requirements and is seeking Commission approval of the proposed arrangements.

Section 4. Preferential Treatment

- PNG has complied with acceptable business practices in its negotiations to provide service to the Triton Project under terms similar to those that would be made available to any party

[2] PNG - West Division, *2012 Revenue Requirements Application to the B.C. Utilities Commission* (November 30, 2011) at Tab 6, online: <http://www.bcuc.com/Documents/Proceedings/2011/DOC_29265_B-1_PNG-West_2012-Revenue-Requirements-Application.pdf>

with similar requirements and is seeking Commission approval of the proposed arrangements. There has been no favoured treatment extended to the Triton Project.

PNG acknowledges that an update to the COC and TPP are in order, particularly as they pertain to activities and transactions with related corporate entities. PNG observes a plan is in place to carry this out.

14.2 Since PNG began conversations with its corporate parent, AltaGas, in July 2015 regarding use of its excess capacity, what changes, if any, have been made to its Code of Conduct?

Response:

There have been no changes in PNG's Code of Conduct in the referenced period. However, as noted in response to Question 14.1, PNG has a plan in place to review and update its Code of Conduct.