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

Verlon G. Otto
Director, Regulatory Affairs

Via E-File

May 10, 2021

British Columbia Utilities Commission
Suite 410 - 900 Howe Street
Vancouver, BC V6Z 2N3

File No.: 4.2(2021)

Attention: Patrick Wruck
Commission Secretary

Dear Mr. Wruck:

Re: Pacific Northern Gas Ltd.
Application for a Certificate of Public Convenience and Necessity for Construction of Kitimat Regulating Station LDS#1
Response to BCUC Information Request No. 1

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

Please direct any questions regarding the application to my attention.

Sincerely,

Original on file signed by:

Verlon G. Otto

Encl.

Pacific Northern Gas Ltd.
Application for a Certificate of Public Convenience and Necessity for Construction of Kitimat Regulation Station LDS #1

INFORMATION REQUEST NO. 1 TO PACIFIC NORTHERN GAS LTD.

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A. AMENDED APPLICATION

1.0 Reference: AMENDED APPLICATION
Exhibit B-2 (Amended Application), Section 1.3, p. 3; Section 3.2.2, p. 10
Proposed Regulatory Process

On page 3 of Pacific Northern Gas Ltd.'s (PNG) application for a Certificate of Public Convenience and Necessity (CPCN) for construction of Kitimat Regulating Station LDS#1 (Amended Application), PNG states:

> Ultimately, the requirement for the LDS#1 asset to be constructed and in place was only delayed by a period of approximately three months, from June 2021 to a revised fixed in-service date of September 1, 2021. To accommodate this requirement, PNG is seeking an expedited regulatory review process that will allow PNG to meet the LDS#1 project construction and operations schedule as detailed in Section 4.4 and is hopeful that it will have BCUC approval no later than June 30, 2021.

On page 10 of the Amended Application, PNG states: "As noted in Schedule A to the GSA [gas sales agreement], firm daily contract demand at commencement date is nil, increasing to a firm daily contract demand of approximately [blacklined] 10^3m^3/day effective April 1, 2022 and further increasing to a firm daily contract demand of [blacklined] effective November 1, 2022, and for the duration of the primary term."

1.1 Please explain the need for the project in-service date of September 1, 2021 if the firm daily contract demand from September 1, 2021 through April 1, 2022 is nil.

Response:

In further accordance with the PNG/JFJV Interface Agreement, JFJV has requested that the construction work on LDS#1 be complete by September 1, 2021 to ensure that construction and commissioning is complete in order to optimize synergies, and minimize complication associated with, ongoing coactive construction in the immediate proximity to the LDS#1 location for the balance of the construction period for the LNG Canada Project.

JFJV have also requested interruptible capacity of 2.45 10^3m^3/day commencing in September 2021 in order to meet anticipated initial gas supply needs at the commencement of the typical local heating season, ramping up in alignment with ongoing construction progression and building occupancy to 10 10^3m^3/day effective April of 2022, when JFJV has committed to firm service. For the purposes of this Application and the associated Mains Extension Test, PNG has not considered the initial interruptible volumes in its financial analysis. As such, any incremental revenues derived from the interruptible volumes will provide positive benefits to all ratepayers.

A copy of the PNG/JFJV Interface Agreement has been provided for BCUC reference, on a confidential basis, along with PNG's responses to BCUC Confidential IR No. 1.

1.2 Please explain any impacts to the project schedule or the GSA if British Columbia Utilities Commission (BCUC) approval of the CPCN is not granted by June 30, 2021.

Response:

Further to PNG response to Question 1.1, in the event that the requested approval date of June 30, 2021 cannot be met, PNG will be unable to meet the agreed in-service date of September 1, 2021 due to resultant impacts on timing of contracting, procurement, and construction activities presently contingent upon the requested approval date. Anticipated resultant impacts on construction progress and completion will result in an increased risk of cost increases and further project delays due to unfavorable fall and early winter weather.

1.3 Please explain any impacts if the in-service date is delayed.

Response:

Please see the response to Question 1.1 and Question 1.2.

B. PROJECT NEED AND JUSTIFICATION

2.0 Reference: BACKGROUND
Exhibit B-2, Section 3.1, p. 9
Construction Period Service and Post-Construction Service

On page 9 of the Amended Application, PNG explains the requests for service it has received from JFJV for the LNGC [Liquefied Natural Gas Canada] Project site. PNG explains the LDS#2 let-down station, granted by BCUC Order C-3-19. PNG explains its plans to construct the LDS#1 let-down station.

2.1 Please explain why two let-down stations (LDS#2 and LDS#1) are required to serve the LNGC Project site.

Response:

PNG submits that two let-down stations are required to serve the LNGC Project site for a multitude of reasons, specifically those associated with the distance of physical separation and intended purpose of the two stations and their end users. The notion of a single let-down station serving the array of future needs of LNG Canada and its associated construction period and activities was first contemplated by PNG in 2015 during conceptual discussions with LNG Canada regarding gas service and the lowering of the existing Methanex-Alcan NPS 6 crossover high pressure pipeline across Beaver Creek and the associated wetland complex. In addition, the single let-down station would have resulted in significantly greater cost, risk, project complexity, and protracted timelines than the eventual two station solution.

The 2-plus kilometre distance between what is now the LDS#2 and the proposed LDS#1 station and end-user sites would have needed interconnecting piping to traverse the fish bearing waters of the Beaver Creek estuarine wetland complex, the properties and rights of way of CN Rail, BC Hydro, Rio Tinto, and the Kitimat Municipal highway, and triggering more comprehensive consultation and notification associated with the need for PNG to obtain new land rights in both brownfield and greenfield settings. Furthermore, the timing and activity details for the end-use purposes associated with both LDS#1 (LNG Canada facility site) and LDS#2 (Cedar Valley Lodge and temporary construction support facilities) could not be accommodated by the construction and operation of a single station.

Gas service in proximity to the current LDS#2 station site was required in advance of ongoing demolition and construction, and eventual gas service, in proximity to the proposed LDS#1 location in order to support temporary facility needs away from the actual LNG Canada plant site. Station and/or pipeline assets could not be built within the actual LNG Canada property in general proximity to, or in service of, the proposed LDS#1 location until all pre-existing legacy assets from the previous Methanex plant operation were demolished and the site readied for new LNG Canada construction. This was inclusive of physical removal of the pre-existing PNG gas service lines traversing portions of the industrial property.

Lastly, through dialogue with the property owner, Rio Tinto, during the development of the LDS#2 project, and early stage conversations related to LDS#1, it was confirmed that there was no long term

interest in having third-party associated gas service related infrastructure on, or traversing, Rio Tinto property due to evolving de-risking interests. It could not be confirmed that beyond the LNG Canada construction durations (Phase 1 and contemplated Phase 2) that Rio Tinto would renew necessary agreements.

2.2 Please explain whether the need for the LDS#1 could have been eliminated if the LDS#2 had been sized to accommodate the longer-term needs of the customer. Please explain the potential cost implications and whether such a project would have been feasible.

Response:

Please refer to the responses to Question 2.1 and Question 3.2. PNG further notes that the purpose of the LDS#2 station and its associated agreements were exclusive to the JFJV-related construction of the LNG Canada Project (4.5 years), while the intended purpose of the LDS#1 station and associated gas service is to support the operating duration of the LNG Canada facility (20+ years).

3.0 Reference: REQUEST FOR POST-CONSTRUCTION NATURAL GAS SERVICE
Exhibit B-2, Section 3.2, p. 10
Contract term beyond 26 months

On page 10 of the Amended Application, PNG states: "Once construction of the LNGC Project is complete, JFJV [JGC Flour BC LNG Joint Venture] will hand-off the facility to LNGC to operate. At this time, it is anticipated that the GSA will be assigned to LNGC, or that PNG will enter into a new contract with LNGC under terms that are the same or similar to those in the GSA. Service to LNGC is projected to be provided for the 20-year life of the LNGC facility."

3.1 Please discuss any potential risks of the contract not extending beyond the 26-month term of the GSA.

Response:

PNG believes that the sole risk of the contract not extending beyond the 26-month term of the GSA is the extremely remote possibility that construction of the LNG Canada Project, one of the largest energy investments in the history of Canada, is not completed and the facility is not commissioned and made operational.

3.2 Please explain why PNG did not secure a contract for the 20-year expected life of the LNGC facility.

Response:

As described in the Amended Application, PNG observes that the initial 26-month contract is with JFJV, the EPC and prime contractor for construction of the LNG Canada facility and that JFJV has exclusive control of the project site. Once construction is completed, JFJV will turn the facility over to LNG Canada for operation. As EPC and prime contractor, JFJV was not in a position to enter into such a long-term contract on behalf of itself and LNG Canada.

4.0 Reference: REQUEST FOR POST-CONSTRUCTION NATURAL GAS SERVICE
Exhibit B-2, Section 3.2, 3.2.2 & 3.2.3, pp. 10-11
Contract Demand

On page 10 of the Amended Application, PNG states: "JFJV has requested that PNG provide firm distribution pressure natural gas sales service for the LNGC Project non-process related facilities once they have been constructed."

On page 11 of the Amended Application, PNG states: "Article 5.5 of the GSA also includes a provision for PNG to provide natural gas sales service to JFJV for demand that is in excess of the contracted firm demand on an interruptible basis, at PNG's sole discretion, as may be required."

4.1 Please provide the maximum capacity of the proposed LDS#1 (GJ/day).

Response:

As per the PNG/JFJV Interface Agreement, the maximum required flow rate to serve the customer is 0.802 MMSCFD at 415 kPa. LDS#1 has the following flow rate expectations:

LDS#1 (overall)	Flow Rate[1] [Sm^3/h]
Maximum	944 (0.802 MMSCFD)
Minimum	66 (7% of maximum)
Normal Operating	472

The maximum flow rate for LDS#1 is 1001 Sm^3/h. The maximum flow per each component of LDS#1 is provided in the table below, illustration that the LDS#1 flow rate is limited by the meter.

Station Component	Max Flow Rate[1] [Sm^3/h]
Line heater	1650
Regulators (current orifice)	1008
Regulators (max orifice)	1413
Flow Meter	1001
Inlet piping (2" XS)	9085
Outlet piping (3" STD)	2626

[1] Based on:
- Inlet Normal Operating Pressure = 6800 kPa
- Inlet Normal Operating Temp = 5C
- Outlet Normal Operating Pressure = 415 kPa
- Outlet Normal Operating Temp = 5C

In the unlikely even that customer demand is higher, the cost to switch out the meter and regulators would be minor (<$10,000). In the unlikely event that customer demand is higher than the line heater limitation, then the cost would be higher.

A copy of the Interface Agreement has been provided for BCUC reference, on a confidential basis, along with PNG's responses to BCUC Confidential IR No. 1.

4.2 Please confirm, or explain otherwise, that the maximum capacity of the proposed LDS#1 can meet the maximum expected demand from JFJV.

Response:

PNG confirms that the maximum capacity of the proposed LDS#1 station can meet the maximum expected demand from JFJV. Furthermore, due to fixed incremental sizing of piping and associated station facility equipment such as the in-line gas heater, inlet filter, and pressure control and over pressure protection, approximately 174% or 1.4 MMSCFD capacity is expected to be available for any potential, but presently unanticipated, growth in service need. Please also see the response to Question 4.1.

5.0 Reference: PROJECT JUSTIFICATIONS AND FINANCIAL BENEFITS
Exhibit B-2, Section 1.1, p. 1; Section 3.4, p. 12; Section 3.4.2, pp. 16-17, Exhibit 3-3; Section 3.4.2, pp. 18-19, Exhibit 3-4
Contract Risks

On page 1 of the Amended Application, PNG states:

> PNG and JFJV have entered into a GSA for firm natural gas sales service at PNG's Large Commercial Sales Rate (RS3) on a take-or-pay basis. This request anticipates commencement of service in September 2021 for an initial service term of 26 months and, subsequently, service is anticipated to be provided to LNGC on a long-term basis for the 20+ year estimated life of the LNGC Project.

In Exhibit 3-3 of the Amended Application, PNG provides the NPV analysis for the proposed LDS#1 asset over the JFJV primary service term. In Exhibit 3-4 of the Application, PNG provides the NPV analysis over the JFJV primary service term plus ongoing service to LNGC.

5.1 Please identify all risks on the expected revenue over the term of the project as included in the both NPV analyses, including but not limited to bankruptcy of either party, termination of the LNGC Project, etc. Please discuss the likelihood of such risks materializing and the impacts upon ratepayers.

Response:

The revenues pertaining to the primary term of the JFJV GSA modeled in the NPV analysis are based on a "take or pay" obligation within the GSA based on a contract demand, thereby "fixing" the minimum revenues expected through the contract term of 26 months. As per Article 14.16 "Several Liability" of the GSA, the JFJV parties are jointly and severally liable to PNG (the Seller).

PNG has identified the following risks on the expected revenue over the primary term of the GSA and beyond:

1. Bankruptcy of both parties to the GSA concurrently.

2. A breach of contract for non payment.

3. Termination of the LNGC Project.

PNG submits that possibility of any these events taking place is very low, as the JFJV joint venture partners are both subsidiaries of very large international entities who are working to build the LNGC export facility in Kitimat. Further, PNG perceives the risk of the LNGC Project, one of the largest energy investments in the history of Canada, not proceeding as very low.

Further, PNG expects the maximum impact to ratepayers to be minimal as Article 8.2 of the GSA provides for an early termination payment equivalent to the net present value of the firm demand

charge multiplied by the daily contract demand for the remainder of the primary term. In addition, as per Article 14.1 of the GSA, PNG may demand a guarantee from each party within the JFJV if PNG has reasonable grounds for insecurity regarding the payments for gas service.

Lastly, as illustrated in Exhibit 3-3 of the Application, PNG reiterates that the GSA arrangements produce a Profitability Index of 1.10 and incremental margin with a NPV of $176,288 in the primary term of service, demonstrating the low risk of adverse impacts on other ratepayers.

6.0 Reference: PROJECT JUSTIFICATIONS AND FINANCIAL BENEFITS
Exhibit B-2, Section 3.4, p. 13
Plant Usage after Estimated Service Term of 20 Years

On page 13 of the Amended Application, PNG states:

> PNG further notes that the financial evaluation that follows is based upon a 25-year analysis period that includes the primary service term with JFJV, an estimated service term of 20 years with LNGC, and a residual 5-year period over which the remaining undepreciated plant balances are amortized after the expiry of the LNGC service term.

In Exhibit 3-3 and Exhibit 3-4, on the line item titled "Depreciation of utility plant," PNG calculates annual depreciation of $53,200 from year 2022 until 2042. Additionally, PNG shows annual Stranded Assets Amortization of $148,960 in the five-year residual period.

6.1 Please confirm, or explain otherwise, that the analyses in Exhibit 3-3 and Exhibit 3-4 are based on a 27-year period (from 2021 to 2047) rather than a 25-year period as indicated on the page 13 of the Application.

Response:

Confirmed. The analysis period presented in Exhibit 3-3 and Exhibit 3-4 covers a 27-year period.

6.2 Please explain, for each of Exhibit 3-3 and Exhibit 3-4, how PNG determined LDS#1 will have five (5) years of residual period after the year 2043.

Response:

In accordance with its established practice, PNG makes use of a 5-year period to amortize assets that are no longer deemed used or useful. While PNG believes that the LDS#1 asset will continue to be used after the initial forecast 20-year term, PNG has taken the conservative approach in its financial evaluation to amortize all the remaining asset balances at the end of this initial forecast 20-year term over the subsequent 5-year period.

6.3 Please explain the likelihood that the plant will be used after the estimated service term of 20 years. If unlikely, please explain why.

Response:

PNG is unable to speculate on whether the LNG Canada facility will be operational beyond the initial service term estimated at 20 years as there are a multitude of factors that could affect how long the facility operates. However, PNG observes that LNG Canada applied for, and the Canada Energy Regulator (formerly, the National Energy Board) has approved, a 40-year natural gas export licence for the facility.

C. PROJECT ALTERNATIVES

7.0 Reference: PROJECT ALTERNATIVES
Exhibit B-2, Section 3.3, p. 12; Appendix E
Project Alternatives

On page 12 of the Amended Application, PNG states: "It was determined that there were no alternatives to the proposal contained in this Application to construct the new LDS#1 regulating station. While LDS#1 is intended to be built on the site of the legacy Methanex Station, refurbishment of the legacy facilities was not an option due to insufficiency of existing infrastructure from a process-support perspective."

7.1 Please elaborate on the alternatives that were considered for the demolition of the legacy Methanex station.

Response:

Further to the response provided in response to Question 2.1, PNG notes that no other alternatives were considered beyond the existing legacy piping asset alteration options explored through the associated Lauren Services Scope Option Review Memorandum provided as Appendix E to the Application.

As noted in Section 3.3 of the Application, with the exception of the building envelope and foundation, the legacy Methanex station has been previously demolished in its entirety. This was conducted in 2016 in the normal course of business with the asset retired as a result. The remaining building envelope and residual piping assets (inlet filter and 10" risers) have been identified to contain both asbestos and lead and no longer comply with building code or process standards, and as such is not acceptable to the customer.

As such, there are no appreciable or suitable assets remaining to refurbish, though PNG notes it does plan to reduce LDS#1 project costs by repurposing a portion of the existing concrete pad.

7.2 Please explain why the legacy Methanex station was deemed to be insufficient and cannot be refurbished.

Response:

Please see the response to Question 7.1.

7.3 Please explain the scope of work that would be required to refurbish the existing Methanex station.

Response:

Please see the response to Question 7.1.

7.4 Please outline the estimated cost to refurbish the existing Methanex station.

Response:

Please see the response to Question 7.1.

7.5 Please explain any impacts to the project schedule if the existing Methanex station was refurbished.

Response:

Please see the response to Question 7.1.

Section 3 of Appendix E presents an analysis of the alternatives for the piping supply to the LDS#1 station:

- Option A: Reuse of the Existing 10" Piping;
- Option B: Removal of the 10" piping/Hot Tap Installation.

In Appendix E to the Amended Application, PNG submits Table 1 comparing the risks and costs of each option. On pages 2-3 of Appendix E to the Application, PNG states: "Re-use of the existing 10" piping (Option A) involves high safety and construction difficulty risks and will result in non-ideal operations and maintenance conditions for the life of Letdown Station #1…It is difficult to determine the likelihood of identifying defects, but as there has been little to no flow for 14 consecutive years, it should be considered low to medium likelihood."

7.6 Please provide a further explanation of each of the risks and costs identified for Option A and Option B in Table 1 of Appendix E.

Response:

Please see the response to Question 7.1. As noted, the determination was made that there are no appreciable or suitable assets from pre-existing infrastructure remaining to be refurbished or repurposed for LDS#1. As to the risks and costs for Option A and Option B as per Table 1 of Appendix E to the Application, please consider the information in the table that follows.

Risk Element	Option A	Option B
Schedule	To use the piping an Engineering and Integrity Assessment would be required as per CSA Z662-19. The 3+ weeks is based on the chance of delay due to contractor availability and the turnaround time to perform this assessment. This timeline could increase significantly and the cost if any piping fails the assessment.	Lower risk option and nothing further to add to information presented in Appendix E.
Outage & Commercial Impact	Nothing further to add to information presented in Appendix E.	Lower risk option and nothing further to add to information presented in Appendix E.

Risk Element	Option A	Option B
Long Term Integrity Concerns	The following is based on the Engineering and Integrity Assessment passing. If issues are identified then this will result in schedule and cost impacts. Exact impacts cannot be quantified until assessment is completed and extent of required works known.	Lower risk option and nothing further to add to information presented in Appendix E.
Construction Difficulty	Work around the high pressure line add complexity for performing the work safely. The constraints to tie into existing brownfield infrastructure slows physical execution and increases the likelihood of rework.	Lower risk option and nothing further to add to information presented in Appendix E.
Operability and Maintenance	The 10" piping is much larger in size and requires a different footprint. This makes working around and maintenance more difficult. The current piping layout is very close to the heavy haul road, presenting long-term safety concerns.	Lower risk option and nothing further to add to information presented in Appendix E.
Safety	Safety concerns have been identified and elaborated upon in the comments above.	Lower risk option and nothing further to add to information presented in Appendix E.
Cost	There is the potential for Option A to end up being the exact same as Option B if the Engineering and Integrity Assessments deem that the current piping is not adequate.	Lower risk option and nothing further to add to information presented in Appendix E.

7.7 Please explain if and how the potential risks associated with Option A could be mitigated.

Response:

PNG would be unable to mitigate the risks identified for Option A. The risks cited in Appendix E to the Application and in the table provided in response to Question 7.6 are inherent in using existing infrastructure and brownfield construction.

7.7.1 Please explain the estimated cost impact of the potential risk mitigation measures discussed in the previous IR response.

Response:

Due to the inherent risks identified, PNG would be unable to mitigate and therefore no costs can be attributed to risk mitigation. Please also see the response to Question 7.7.

7.8 Please explain any other evaluation criteria PNG considered in selecting Option B over Option A.

Response:

No additional evaluation was performed or considered necessary to PNG's determination and selection of Option B over Option A.

8.0 Reference: PROJECT ALTERNATIVES
Exhibit B-2, Section 3.3, p. 12; Section 4.2, p. 23; Section 5.1.1, p. 25, Exhibit 5-1
Demolition Costs

On page 23 of the Amended Application, PNG states that the primary construction elements for LDS#1 include demolition of existing building and piping, pipe shop fabrication of new station, site civil preparation, hot tap isolation for tie-in and final commissioning.

On page 12 of the Amended Application, PNG states:

> As part of the options analysis, it was determined that there were alternative approaches for piping to supply LDS#1. Lauren Services completed a Scope Option Review Memorandum on 14 this aspect of the project, and this has been included for reference as Appendix E to this 15 Application. PNG notes that both piping alternatives involve demolition of the existing Methanex Station building and partial demolition of the associated concrete slab.

On page 25 of the Amended Application, PNG provides the following table showing the captital cost components of LDS# 1:

Exhibit 5-1 – LDS#1 Capital Cost Components

Capital Component		Cost
Indirect:		
Engineering	$	132,000
Survey, Lands & Regulatory (BC OGC)		40,000
Internal Labour		18,000
		190,000
Direct:		
Construction - Mechanical Contractor		737,000
Materials		156,000
Construction - Hot Tap and Isolation		152,000
Construction - Management		44,000
Non-Destructive Examination		32,000
		1,121,000
Subtotal		1,311,000
Overhead (19%)		308,000
Subtotal including Overhead		1,619,000
Contingency (15%)		243,000
Total Capital Cost	**$**	**1,862,000**

8.1 Please provide the estimated demolition cost for each piping alternative and explain any significant differences.

Response:

The costs associated with Option A and Option B of the Lauren Services Scope Option Review Memorandum were intended for comparison purposes only and were intentionally not inclusive of project costs common to both options, i.e. costs of the demolition of the existing building and partial demolition of the concrete pad were excluded as this was common to both projects.

That said, the following are estimated demolition and disposal costs:

- Option A - $5,000 for demolition and disposal of coalescing filter.
- Option B - $7,500 for demolition and disposal of coalescing filter and 10" piping upstream and downstream of filter.

The difference between Option A and Option B is that Option A does not demolish the existing 10" piping upstream and downstream of the filter that is considered an integrity risk and safety hazard due to heavy haul traffic in very close proximity.

8.2 Please clarify whether the estimated demolition cost for the proposed piping approach is included in the breakdown of the LDS#1 Capital Cost Components shown on page 25 of the Amended Application. If yes, please specify in which line item(s) the estimated costs are included.

Response:

The estimated costs for demolition and disposal are included in the LDS#1 capital cost as part of the Construction – Mechanical Contractor cost of $737,000 as per Exhibit 5-1 of the Application as reproduced in the preamble to this series of questions.

8.3 Please provide an alternative Capital Cost Breakdown for LDS#1 by primary construction elements (i.e. demolition of existing building and piping, pipe shop fabrication of new station, site civil preparation, etc.).

Response:

As per Exhibit 5-1 of the Application as reproduced in the preamble to this series of questions, the primary construction cost elements are:

Capital Component	Cost
Construction – Mechanical Contractor	$737,000
Construction – Hot Tap and Isolation	152,000
Construction – Management	44,000
Construction Total	$933,000

The table that follows provides an alternative capital cost breakdown by primary construction elements.

Construction Element	Cost
Supervision, Support and Indirects	$178,800
Hot Tap and Isolation	151,900
Pipe Shop Fabrication	130,800
Site Mechanical	101,700
Site Civil	73,400
Mobilization and Demobilization	68,900
Demolition and Disposal	61,900
Site Electrical and Instrumentation	55,000
Subsistence	46,000
Inspection	44,000
Construction Total	$912,400

PNG notes that the construction total in the breakdown by capital component of $912,400 is less than the cost components as per Exhibit 5-1 of the Application of $933,000. This decrease can be attributed to an incorrect duplicate entry for fencing costs of $20,000 as both a sub-task of site civil and as a separate line item. With the elimination of this duplication, the overall estimated capital cost of LDS#1 has been amended to $1,833,000 as summarized in the table that follows.

Capital Component		Cost
Indirect:		
Engineering	$	132,000
Survey, Lands & Regulatory (BC OGC)		40,000
Internal Labour		18,000
		190,000
Direct:		
Construction - Mechanical Contractor		717,000
Materials		156,000
Construction - Hot Tap and Isolation		152,000
Construction - Management		44,000
Non-Destructive Examination		32,000
		1,101,000
Subtotal		1,291,000
Overhead (19%)		303,000
Subtotal including Overhead		1,594,000
Contingency (15%)		239,000
Total Capital Cost	**$**	**1,833,000**

9.0 Reference: PROJECT ALTERNATIVES
Exhibit B-2, Section 5.1.1, p. 25, Exhibit 5-1; Appendix E Lauren Services Scope Option Review Memorandum, p. 3
Piping Options

In the following excerpt from Table 1 of Appendix E of the Amended Application, Lauren Services presents the following table showing a breakdown of the costs for executing piping Option B:

Cost	Option B – Removal of 10" Piping / Hot Tap & Isolation
Engineering	$5,000
Materials	$3,000
Construction	$153,400
NDE	Included in construction
Sub-Total	**$161,400***

On page 4 of the Appendix E, Lauren Services states: "It is recommended that Option B is selected."

On page 25 of the Amended Application, PNG provides the following table showing the captital cost components of LDS# 1:

Exhibit 5-1 – LDS#1 Capital Cost Components

Capital Component		Cost
Indirect:		
Engineering	$	132,000
Survey, Lands & Regulatory (BC OGC)		40,000
Internal Labour		18,000
		190,000
Direct:		
Construction - Mechanical Contractor		737,000
Materials		156,000
Construction - Hot Tap and Isolation		152,000
Construction - Management		44,000
Non-Destructive Examination		32,000
		1,121,000
Subtotal		1,311,000
Overhead (19%)		308,000
Subtotal including Overhead		1,619,000
Contingency (15%)		243,000
Total Capital Cost	**$**	**1,862,000**

9.1 Please confirm, or explain otherwise, that the $1,862,000 estimated total capital cost of LDS#1 is based on Lauren Services' recommendation that piping Option B is selected.

Response:

Confirmed.

9.1.1 If confirmed, please explain and provide a supporting schedule showing how the estimated cost of Option B ($161,400 in the Appendix E) reconciles to the breakdown of LDS#1 Capital Cost Components shown in Exhibit 5-1 stating in which line item(s) the costs are included.

Response:

PNG notes that it is not possible to reconcile the figures per the Lauren Services Scope Option Review Memorandum to the final cost estimate, as cost estimates were further refined to a Class 3 total installed cost (TIC) and work breakdown structure (WBS) after the Option A/B assessment was completed.

That said, the estimated engineering costs for Option B would be captured in the Engineering cost line item of Exhibit 5-1, the estimated materials cost for Option B would be captured in the Materials cost line item of Exhibit 5-1, and the estimated construction costs for Option B would be captured in the Construction – Materials Contractor cost line item of Exhibit 5-1.

Please also see the capital cost breakdown by primary construction elements provided in response to Question 8.3.

9.2 Please provide Capital Cost Components (similar to Exhibit 5-1) for the project alternative with piping Option A selected.

Response:

PNG notes that it is not possible to provide this information as cost estimating for Option A was not advanced to the same degree following this option being ruled out as the preferred project option. This is consistent with project practice when leveraging alternatives analysis at a screening level during pre-FEED activities.

That said, the estimated engineering costs for Option A would have been captured in the Engineering cost line item of Exhibit 5-1, the estimated construction costs for Option A would be captured in the Construction – Materials Contractor cost line item of Exhibit 5-1, and the estimated non-destructive examination (NDE) costs for Option A would be captured in the Non-Destruction Examination cost line item of Exhibit 5-1.

9.3 Please explain the definition of Internal Labor and what costs are included.

Response:

Internal labour represents the costs of upfront work and supervision provided by PNG staff. This is a small dollar item as the majority of work is to be performed by contractors. However, PNG crews would still support on certain activities such as blowdowns of current pressurized piping.

D. PROJECT DESCRIPTION

10.0 Reference: PROJECT DESCRIPTION
Exhibit B-2, Section 4.1, p. 22; Appendix G
Project Layout and Location

On page 22 of the Amended Application, PNG states: "The project site is located on private property owned by LNGC. As part of the planning for this project, the existing lands agreement between PNG and LNGC has been replaced by a new statutory right of way."

10.1 Please confirm the costs, whether one-time or annual lease, to PNG to acquire the Right of Way.

Response:

PNG paid one-time consideration of $1 to acquire the right of way.

E. PROJECT COST ESTIMATE

11.0 Reference: COST OF SERVICE FORECAST
Exhibit B-2, Section 3.4.2, pp. 16-17; Exhibit 3-3; Section 3.4.2, pp. 18-19, Exhibit 3-4 Section 5.2, p. 26; Appendix B-1 PNG Response to PNG-West 2020-2021 Revenue Requirement Application (RRA) BCUC Information Request (IR) 52 Series, p. 3
Maintenance Costs

On page 26 of the Amended Application, PNG states:

> As LDS#1 is a newly constructed asset, annual operating costs are expected to be negligible and over the analysis period are anticipated to related primarily to meter reading, billing activities, fuel gas costs and property taxes. Operating costs are estimated to be approximately $2,000 annually.

11.1 Please provide the basis for estimated annual operating costs of $2,000 over the entire NPV analysis period.

Response:

PNG has used $2,000 as a conservative placeholder for annual operating costs in its financial analysis. PNG expects the project asset to incur minimal operating costs over the analysis period.

11.2 Please explain whether PNG considers that annual operating costs may increase, decrease or stay the same over time as LDS#1 ages and how this is taken into consideration in the cost of service forecast.

Response:

Please see the response to Question 11.1. As noted, PNG has included a conservative placeholder for annual operating costs in its financial analysis and expects to incur minimal operating costs over the analysis period.

PNG notes that the estimated operating costs include an upward adjustment to reflect 2% forecast annual inflation. For context, PNG notes that doubling the operating costs every year over the analysis period changes the Profitability Index by only a small amount, reducing it to 6.52 from 6.59. If the annual operating costs are removed from the analysis, the Profitability Index modestly increases to 6.66 from 6.59.

11.3 Please clarify whether maintenance expenses are included in the estimated annual operating costs. If not, please explain why not. If yes, please explain specify where (e.g. which line item) maintenance costs are factored in the NPV calculations in Exhibit 3-3 and Exhibit 3-4.

Response:

PNG has given consideration to future maintenance capital costs for the LDS#1 project and expects the project to incur no additional maintenance capital over the analysis period. Please also see the response to Questions 11.1 and 11.2.

11.3.1 If maintenance costs have not been included, please provide an estimate of the annual maintenance costs over the life of the asset.

Response:

Please see the response to Question 11.3.

12.0 Reference: CAPITAL COST ESTIMATE
Exhibit B-2, Section 5.1, p. 25; Appendix B-1 PNG Response to PNG-West 2020-2021 RRA BCUC IR 52 Series, BCUC IR 52.5
2020 Actual Cost

In Appendix B-1, PNG provides the following response to BCUC IR 52.5 from the PNG-West 2020-2021 RRA proceeding showing the forecast and actual costs for a "LNG Canada Let Down Station #1" project:

	2019		2020	2021	Total Project
	Decision	Actual	Forecast	Forecast	Cost Forecast
LNG Canada Let Down Station #1	-	$48,370	$1,147,825	$217,394	$1,413,590

12.1 Please provide an updated response to BCUC IR 52.5 from the PNG-West 2020-2021 RRA proceeding, including 2020 actual costs and updated forecast cost for 2021 and the Total Project Cost Forecast.

Response:

Please see the table that follows for a breakdown of actual costs in 2019, 2020 and 2021 year-to-date, as well as the total forecast costs for 2021.

	2019	2020	2021		Total
	Actual	Actual	Actual (YTD)	Forecast	Forecast
LNG Canada LDS#1	$ 48,370	$ 143,534	$ 51,240	$ 1,641,096	$ 1,833,000

13.0 Reference: **CAPITAL COST ESTIMATE**
Exhibit B-2, Appendix H Lauren Services Basis of Estimate (Class 3), pp. 3-4, 10-11
PNG Application for a CPCN for the Construction of Kitimat Regulating Station LDS #2 proceeding, Exhibit B-1, p. 21
Overhead, Contingency and Estimate Accuracy

On page 25 of the Amended Application, PNG states it engaged Lauren Services to assist with project planning, including the preparation of a cost estimate to support development of the LDS#1 project. A copy of the Basis of Estimate prepared by Lauren Services is included as Appendix H.

In Table 2 of Appendix H to the Amended Application, Lauren Services presents the following table showing the estimated cost for the project, including contingency, with an assumed estimating accuracy of +30%/-20%:

Table 2: Total Cost Estimate Summary

PNG Overhead + PNG Labour	$308,000.00
Engineering & Permitting, Survey, Lands and Regulatory	$172,000.00

Lands and Land Rights	$0.00
Materials	$156,000.00
Construction	$888,000.00
Construction & NDE Inspection	$76,000.00
Outage & Gas Loss	$0
TOTAL w/o contingency	**$1,619,000.00**
Contingency (15%)	**$243,000.00**
TOTAL w/ Contingency (accuracy +30%/-20%)	**$1,862,000.00**

On page 21 of Exhibit B-1 in the PNG Application for a CPCN for the Construction of Kitimat Regulating Station LDS #2 proceeding, PNG stated a contingency for the project of 20 percent and an expected estimating accuracy of +15%/-10%.

13.1 Please explain why the estimated accuracy is +30%/-20% in LDS#1 whereas the LDS#2 had an estimate accuracy of +15%/-10%.

Response:

Two primary factors contributed to improved accuracy of the LDS#2 cost estimate compared to the LDS#1 estimate:

1) At the time of cost estimate preparation, PNG had received bids from contractors for work on the LDS#2 project; PNG was not that far into the process for LDS#1 when the cost estimate was formed; and

2) For LDS#1 there are differing considerations for site coactivity and the JFJV construction interface, as well as demolition unknowns and the need to address hazardous materials, including the presence of lead-based paint and asbestos, as previously outlined in Section 3.3 of the Application and in the response to Question 7.1.

13.2 Please explain why a contingency of 15 percent is appropriate for the LDS#1. Additionally, please explain the reason for different contingency in this application compared to the LDS#2 application.

Response:

PNG is of the view that a 15% contingency is appropriate with the selected option and the identified risks. LDS#2, while similar, is a project with a different scope and that involved a different set of risks. PNG has applied lessons learned from LDS#2 to LDS#1 where the scope is considered similar. PNG observes that regardless of the provision for contingency, only actual costs incurred are capitalized.

In section 8.4 of Appendix H of the Amended Application, PNG states: "PNG Overhead is included as 19% of the total installed cost, inclusive, as requested by PNG for 2020 projects."

13.3 Please confirm, or explain otherwise, that PNG applies a standard contingency allowance of 19 percent on all capital projects. If not confirmed, please explain why PNG selected a contingency allowance of 19 percent for the LDS#1 project.

Response:

PNG notes that the 19 percent provision applies to Overhead, not Contingency as indicated in the question.

In forecasting capital projects, PNG typically includes an overhead provision to account for PNG's internal costs that are allocated to capital projects as transfers to capital, including costs associated with project management, project engineering, supply chain management, finance, accounting, legal and lands that are normally attributable to capital projects.

PNG's allocation of overhead costs to capital projects is dependent on the annual pool of overhead costs to be allocated, which remains fairly constant on an annual basis but is subject to inflationary and other increases each year, as well as the expected level of annual capital expenditures which attract overheads.

Overhead costs are allocated to a project based on the project's pro rata share of the total cost of capital projects which attract overheads for that year. If the actual capital projects that attract overheads is higher compared to the annual budget, then the amount of overhead applied to a specific project will generally be lower than originally forecast as the total overhead pool to be distributed to projects does not change. The opposite also applies, so if the actual capital projects are lower than budgeted, then the overhead allocated to a specific project will generally be higher than initially forecast.

PNG considers the 19% provision for internal overhead to be conservative and notes that the financial evaluation of the proposed project remains strong despite the conservative amount allowed for in the cost estimate. PNG further notes that regardless of the conservative provision for overhead, only the final overhead allocation will be capitalized.

On page 25 of the Amended Application, PNG provides Exhibit 5-1 showing the capital cost components of LDS#1. PNG noted in Exhibit 5-1 that Internal Labour cost is $18,000 and Constructions costs are $889,000 ($737,000 + $152,000).

13.4 Please explain the following and provide a revised Table 2 for Appendix H or Exhibit 5-1, as needed:

a. Please explain where the internal labour costs of $18,000 are included in Table 2 of Appendix H.

Response:

In Table 2 of Appendix H, internal labour costs were to be included in the first row "PNG Overhead + PNG Labour". PNG notes that the table presented in Appendix H contained an error in that it did not include this amount, and hence the table did not add correctly. PNG apologizes for any inconvenience as a result of this error. A corrected version of Table 2 is produced below.

Table 2: Total Cost Estimate Summary

PNG Overhead + PNG Labour	**$326,000**
Engineering & Permitting, Survey, Lands and Regulatory	$172,000
Lands and Land Rights	nil
Materials	$156,000
Construction	$888,000
Construction & NDE Inspection	$76,000
Outage & Gas Loss	nil
TOTAL w/o contingency	**$1,619,000**
Contingency (15%)	**$243,000**
TOTAL with Contingency (accuracy +30%/-20%)	**$1,862,000**

b. Please reconcile the construction-related costs in Table 2 of Appendix H to the construction-related costs in Exhibit 5-1.

Response:

Table 2 of Appendix H is intended to be a summary table with values rounded to the nearest $1,000. The estimated construction cost is $888,397, which has been rounded to $888,000 for inclusion in Table 2 of Appendix H.

The corresponding line items from Exhibit 5-1 are as follows, where the estimated construction costs of $888,397 have been rounded up to $889,000.

Capital Component	Cost
Construction – Mechanical Contractor	$737,000
Construction – Hot Tap and Isolation	152,000
Construction Total	$889,000

In section 11.0 of Appendix H to the Amended Application, Lauren Services provides a list of exclusions to the capital cost estimate.

13.5 Please provide a brief description and the rationale for each of the four listed exclusions.

Response:

Appendix H, the Lauren Services Basis of Estimate, noted four exclusions:

1) Import duties;
2) Taxes;
3) Escalation; and
4) AFUDC.

Please consider the following discussion of each of these items.

1) Import duties

- An import duty is a tax collected on imports by a country's customs authorities. The amount of the import duty, if any, will depend on the country where PNG purchases material from.
- This is typically excluded from third party cost estimates as it cannot reasonably be determined by the third party.
- PNG does not anticipate purchasing any materials for this project outside of Canada.

2) Taxes

- The BC provincial sales tax (PST) is a retail sales tax that applies when a taxable good or service is purchased, acquired or brought into BC for use in BC, unless a specific exemption applies.

- PNG notes that the LDS#1 project is a necessary component of the LNG Canada project being constructed in Kitimat.
- The British Columbia Ministry of Finance's 'Bulletin PST 212' issued October 2018 outlines the PST exemptions that apply to the LNG Canada project in Kitimat.
- PNG believes that 'Bulletin PST 212' applies to the LDS#1 project and that the project is PST exempt.

3) Escalation

- Escalation refers to the price increase of materials and labour between the time the cost estimate is conducted and the time that the expenditures are made.
- PNG does not believe that it will face a cost escalation in the estimate for LDS#1.

4) AFUDC

- AFUDC is an acronym that stands for "allowance for funds used during construction" and is a component of construction costs representing the net cost of borrowed funds and a reasonable rate on other funds used during the period of construction.
- AFUDC is capitalized until the project is placed in operation by concurrent credits to the income statement and charges to utility plant, based generally on the amount expended to date on the particular project.
- AFUDC is excluded from third-party cost estimates as is cannot be reasonably estimated by the third party.
- Given that only $192,000 in costs were incurred for LDS#1 in 2019 and 2020, AFUDC on the project will be negligible.

PNG observes that the cost estimate for LDS#1 includes a 15% contingency and is of the view that this provision will address any unexpected cost increases that may arise from these four exclusions.

14.0 Reference: BACKSTOP ARRANGEMENTS
Exhibit B-2, Section 5.3, pp. 25-26
PNG-JFJV LDS#1 Engineering Costs Letter Agreement

PNG states on page 26 of the Amended Application:

> …PNG and JFJV have entered into a backstop arrangement to cover costs up to $230,000 for preliminary engineering design, cost estimate, permitting, and planning for LDS#1.

A copy of the above-noted backstop arrangement between PNG and JGC Flour, titled the "Engineering Costs Letter Agreement," is provided by PNG in confidential Appendix I-1.

PNG provides a breakdown of the capital cost components of LDS#1 in Exhibit 5-1 on page 25 of the Amended Application:

Exhibit 5-1 – LDS#1 Capital Cost Components

Capital Component		Cost
Indirect:		
Engineering	$	132,000
Survey, Lands & Regulatory (BC OGC)		40,000
Internal Labour		18,000
		190,000
Direct:		
Construction - Mechanical Contractor		737,000
Materials		156,000
Construction - Hot Tap and Isolation		152,000
Construction - Management		44,000
Non-Destructive Examination		32,000
		1,121,000
Subtotal		1,311,000
Overhead (19%)		308,000
Subtotal including Overhead		1,619,000
Contingency (15%)		243,000
Total Capital Cost	**$**	**1,862,000**

14.1 Please provide a description of the circumstances which could trigger JFJV's backstop obligation as described in the Engineering Costs Letter Agreement.

Response:

The circumstances which would trigger JFJV's backstop obligation within the Engineering Costs Letter Agreement are as per item 1. of the Engineering Costs Letter Agreement, specifically, the earlier of:

- if the Engineering Costs Letter Agreement was terminated by either Party;
- March 31, 2020; or
- the date of entering into a Gas Sales Agreement (GSA).

Based on the foregoing, JFJV's backstop obligation under the Engineering Costs Letter Agreement has been triggered by virtue of the passage of time, and the noted March 31, 2020 date. Further, PNG notes that the GSA was entered into on August 11, 2020.

14.2 Please reconcile the $230,000 which is covered by the Engineering Costs Letter Agreement to the Engineering costs of $132,000 shown in Exhibit 5-1 above. If the engineering costs are $132,000, does this mean that the remaining portion of the backstop arrangement is forfeited? Please explain.

Response:

As stipulated in the Engineering Costs Letter Agreement, the $230,000 was a high-level estimate of costs for "preliminary engineering process required to: design, prepare a cost estimate, permit and plan the installation of a reconfigured or new pressure let down and metering station".

As per Exhibit 5-1, the $132,000 represents the anticipated actual engineering cost. To date, PNG has incurred costs for the full amount of the Engineering Costs Letter Agreement, including engineering costs and additional costs related to permitting and planning. There is no forfeiture of backstopped amounts.

14.3 Please explain whether any of the backstopped costs from the Engineering Costs Letter Agreement have been incurred to date.

Response:

To date, PNG has incurred costs for the full amount backstopped by the Engineering Costs Letter Agreement. Please see also the response to Question 14.2.

14.4 Please explain whether the costs recovered via the Engineering Costs Letter Agreement are netted against the Total Capital Costs of $1,862,000.

Response:

The Engineering Costs Letter Agreement backstops certain engineering and planning costs included within the LDS#1 cost estimate. The Engineering Costs Letter Agreement provides for JFJV funding support for the identified activities in advance of their committing to future obligations for service as per the GSA.

14.5 Please discuss any risks that PNG would be unable to recover the covered costs up to the agreed amount of $230,000 under this backstop agreement.

Response:

With the execution of the GSA, the Engineering Costs Letter Agreement has been terminated (see Section 1 of the Engineering Costs Letter Agreement), and JFJV is now contractually obligated to pay PNG for the requested gas service for the duration of the primary term of the GSA. The GSA takes into consideration the full cost of this project, and therefore includes all costs including those backstopped by the Engineering Costs Letter Agreement.

14.6 Please provide the cost to PNG of entering the Engineering Costs Letter Agreement and explain how these costs are recovered from ratepayers, if at all.

Response:

The cost of PNG's external Legal Counsel involvement in preparation of the Engineering Costs Letter Agreement have been funded as part of the 2019 general corporate legal costs of $57,304 as reflected in the PNG-West 2018-2019 Revenue Requirements Application approved under BCUC Orders G-151-18 and G-221-18.

15.0 Reference: BACKSTOP ARRANGEMENTS
Exhibit B-2, Section 5.3, pp. 25-26
PNG-JFJV LDS#1 Backstop Letter Agreement

PNG states on page 26 of the Amended Application: "PNG and JFJV have also entered into a backstop arrangement to cover costs up to $210,000 for demolition and site preparation, and for procurement of long-lead materials for the service request."

A copy of the above-noted backstop arrangement between PNG and JGC Flour, titled the "Backstop Letter Agreement," is provided by PNG in confidential Appendix I-2.

15.1 Please provide a description of the circumstances which would trigger JFJV's backstop obligation as described in the Backstop Letter Agreement.

Response:

The circumstances which would trigger JFJV's backstop obligation within the Backstop Letter Agreement are as per item 1. of the Backstop Letter Agreement, specifically, the earlier of:

- If the Backstop Letter Agreement is terminated by either party;
- May 31, 2021; or
- Date of BCUC approval of PNG's application for the LDS#1 CPCN.

PNG advises that, in consideration of the regulatory process presently underway to review the Application, PNG and JFJV have agreed to amend the Backstop Letter Agreement, revising the May 31, 2021 date noted, to July 31, 2021.

15.2 Please explain whether any of the backstopped costs from the Backstop Letter Agreement have been incurred to date.

Response:

To date, PNG has incurred and been invoiced the amount of $13,144 for work covered by the Backstop Letter Agreement. PNG further notes that it has open commitments with vendors up to the maximum amount of the backstopped costs under the Backstop Letter Agreement.

15.3 Please discuss any risks that PNG would be unable to recover the covered costs up to the agreed amount of $210,000 under this backstop agreement

Response:

PNG has identified the following risks that PNG would be unable to recover the costs incurred up to the agreed amount of $210,000 under the backstop agreement:

1. Bankruptcy of both parties to the GSA concurrently.
2. A breach of contract for non payment.
3. Termination of the LNGC Project.

PNG submits that the possibility of any of these events taking place is very low, as the JFJV partners are both subsidiaries of very large international entities who are working to build the LNG Canada export facility in Kitimat. Further, PNG perceives the risk of the LNG Canada Project, one of the largest energy investments in the history of Canada, not proceeding as very low.

15.4 Please provide the cost to PNG of entering the Backstop Letter Agreement and explain how these costs are recovered from ratepayers, if at all.

Response:

The cost of PNG's external Legal Counsel involvement in preparing the Backstop Letter Agreement have been funded as part of 2020 forecast Business Development legal costs of $20,000 as reflected in the PNG-West 2020-2021 Revenue Requirements Application approved under BCUC Order G-255-20.

F. CONSULTATION

16.0 Reference: CONSULTATION
Exhibit B-2, Section 6.1, 6.2, p. 27
Public and Indigenous Consultation

On page 27 of the Amended Application, PNG discusses its public and indigenous consultation on the Project to date. PNG states: "On this basis, PNG is of the view that no formal public consultation is required for LDS#1."

16.1 Please provide a summary of any feedback PNG has received on the Project to date.

Response:

Aside from the letter of support from the Municipality of Kitimat included as Appendix J to the Application, no further feedback has been received related to the Project.

As indicated in the Application, LDS#1 will be constructed to replace an existing asset and will be sited on a new statutory right of way on private land owned by LNG Canada, the ultimate customer being served.

16.2 Please explain whether there are any potential impacts specifically resulting from the construction of the Project that would warrant further consultation.

Response:

There are no identifiable potential impacts specifically resulting from the construction of the Project that would warrant further consultation. Please see the response to Question 16.1.