Appendix C

Information Required by 18 C.F.R. § 157.34(c)

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Pursuant to the requirements of 18 C.F.R. §157.34(c), additional information regarding the Alaska Pipeline Project ("APP") Open Season is provided below. Unless otherwise specified, the information provided applies to both the Alaska-Canada Pipeline and the Valdez Pipeline systems.

Item 1 - Pipeline Routes

18 C.F.R. §157.34(c)(1): The general route of the proposed project, including receipt and delivery points, and any alternative routes under consideration; delivery points must include those within the State of Alaska as determined by the In-State Study in (b) above.

General Route

The Alaska Pipeline Project will consist of:

- A FERC jurisdictional gas treatment plant ("GTP") near Prudhoe Bay, Alaska, which will treat North Slope gas for pipeline transportation;
- A FERC jurisdictional gas transmission pipeline from the outlet of the Point Thomson plant in Alaska to the GTP and from there, subject to shipper confirmation during the Open Season process, to either:
    - The Alaska/Canada border for onward delivery to Alberta, Canada (the "Alaska-Canada Pipeline"); or
    - Valdez, Alaska (the "Valdez Pipeline").

With the Alaska-Canada Pipeline, shippers would have the ability to deliver gas to North American markets through the Alberta Hub or other existing off-take capacity at or near the British Columbia/Alberta border. With the Valdez Pipeline, shippers would have the ability to deliver into a liquefied natural gas ("LNG") facility (to be developed by third parties), for onward delivery to global LNG markets. The Alaska-Canada Pipeline and the Valdez Pipeline are alternative proposals. Depending on customer interest as evidenced in the Open Season, APP will proceed with either the Alaska-Canada Pipeline or the Valdez Pipeline, but not both.

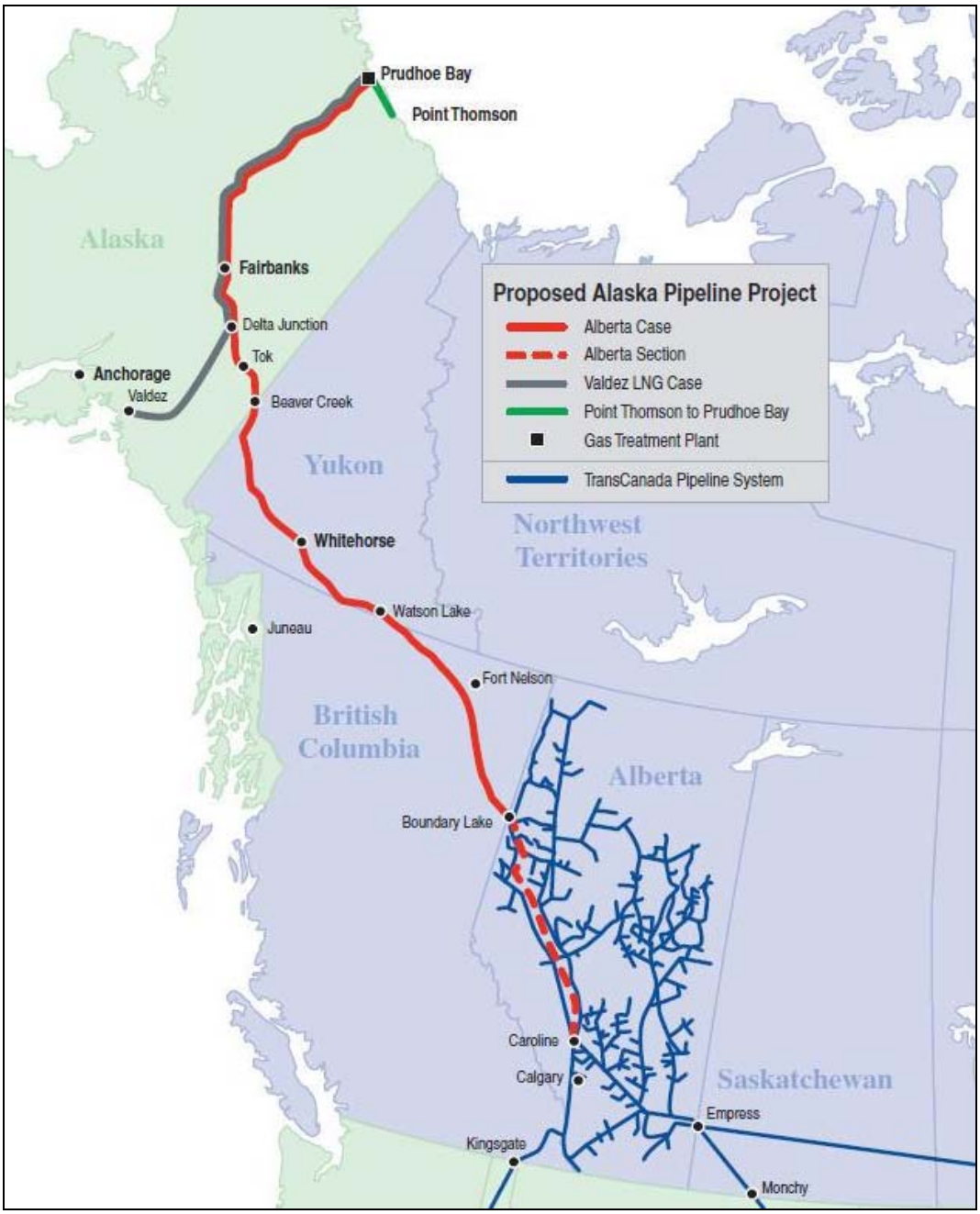
The proposed pipeline segment from the outlet of the Point Thomson plant to the inlet to the GTP will generally run parallel to (offset to the south) the future above-ground Point Thomson to Badami oil pipeline and the existing Badami to Endicott oil pipeline. As the route approaches the West Channel of the Sagavanirktok River and Prudhoe Bay facilities, the pipeline will cross the Endicott pipeline and head directly to the GTP site.

The remainder of the proposed Alaska-Canada Pipeline would extend from the outlet of the GTP past points near Fairbanks, and Delta Junction and then to the Alaska-Canada border where it would interconnect to a new pipeline that APP plans to design, permit and construct ("Canadian Pipeline"). The proposed Canadian Pipeline would head past Whitehorse, and extend to Boundary Lake, Alberta.

The remainder of the proposed Valdez Pipeline would follow a similar route from the outlet of the GTP to Delta Junction before heading to an interconection point with LNG facilities near Valdez.

These proposed general routes are shown in the Figure 1 below. Additional route maps are provided in Exhibits A to E of this Appendix C.

Figure 1: Proposed Pipeline Route



Receipt Points

Receipt points will be provided at the inlet and outlet of the GTP for North Slope Shippers seeking entry into the line. There will also be a receipt point at the inlet of the Point Thomson plant. Other tie-in and receipt points will be provided at various intervals along the pipeline route as determined by the results of the Open Season and as requested by shippers.

Delivery Points

There will be a delivery point at the inlet of the GTP for the Point Thomson pipeline segment and at either the Canadian border or Valdez, depending on which alternative route is selected. In addition, a minimum of five (5) delivery points in the State of Alaska for local demand will be provided on a firm or interruptible basis. For purposes of the Open Season, Exhibit A to the Precedent Agreement specifies the following delivery points, which were identified by the In-State Needs Study as the most likely off-take points based on expected demand.

Table 1: Potential Alaska In-State Delivery Points

Location	Alaska-Canada Pipeline Route	Valdez Pipeline Route
Livengood	√	√
Fairbanks	√	√
Parks Highway spur	√	√
Delta Junction area/Richardson Highway spur	√	√
Tok	√	n/a
Glennallen	n/a	√
Valdez	n/a	√

The final determination of the locations that will be served will depend on which alternative route is selected, the results of the Open Season and input from potential shippers. APP will make provision for delivery along the pipeline at the points finally selected through the installation of tees and blind flanges.

For information, the Northern Pipeline Act ("NPA") also requires a minimum of eight (8) off-takes in Canada in the event the Alaska-Canada Pipeline alternative is selected. In that case, the interconnected Canadian Pipeline will have, in addition to delivery to existing facilities at Boundary Lake in Canada, offtake points near Beaver Creek, Burwash Landing, Destruction Bay, Haines Junction, Whitehorse, Teslin, and Upper Liard/Watson Lake as identified in the NPA.

Item 2 - Project Design And Capacities

18 C.F.R. §157.34(c)(2): Size and design capacity (including proposed certificate capacity at the delivery points named in (1) above to the extent that it differs from design capacity), a description of possible designs for expanded capacity beyond initial capacity, together with any estimated date when such expansions designs may be considered;

Size and Design Capacity

The proposed Project will have the size and design capacities summarized in Table 2 below.

Table 2: Proposed Size and Design Capacities

Section Of The Proposed Project	Design Parameter	Value
Point Thomson Pipeline	Pipeline diameter (inches)	32
	Pipeline grade	X65
	Pipeline length (miles)	58
	Pipeline capacity (base design – Bcf/d)	1.1
	Pipeline capacity (with max compression – Bcf/d)	1.5
	Inlet gas receipt temperature (°F)	30
	Minimum design outlet gas delivery temperature (°F)	2
GTP For The Alaska-Canada Pipeline	Processing capacity – inlet raw gas (Bcf/d)	5.3
	Processing capacity – CO_2 (Bcf/d)	0.6
	Delivery capacity – outlet sales gas to pipeline (Bcf/d)	4.5
	Inlet gas average receipt temperature (°F)	60
	Outlet gas delivery temperature (°F)	< 30
	Outlet CO_2 temperature (°F)	100+

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
GTP For The Valdez Pipeline	Processing capacity – inlet raw gas (Bcf/d)	3.6
	Processing capacity – CO_2 (Bcf/d)	0.44
	Delivery capacity – outlet sales gas to pipeline (Bcf/d)	3.0
	Inlet gas average receipt temperature (°F)	60
	Outlet gas delivery temperature (°F)	< 30
	Outlet CO_2 temperature (°F)	100+
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Pipeline diameter (inches)	48
	Pipeline grade	X80
	Pipeline length – Alaska (miles)	734
	Pipe capacity (base design – Bcf/d)	4.5
	Pipe capacity (with max compression – Bcf/d)	5.9
	Inlet gas receipt temperature (°F)	< 30
	Minimum design outlet gas delivery temperature (°F)	26
	Outlet gas delivery point capacity – Livengood (MMcf/d)	No less than the In-State Needs Study value of 9
	Outlet gas delivery point capacity – Fairbanks (MMcf/d)	No less than the In-State Needs Study value of 55
	Outlet gas delivery point capacity – Parks Highway Spur (MMcf/d)	Included in Fairbanks capacity

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Outlet gas delivery point capacity – Delta Junction/Richardson Highway Spur (MMcf/d)	No less than the In-State Needs Study value of 272
	Outlet gas delivery point capacity – Tok (MMcf/d)	No less than the In-State Needs Study value of 0.4
	Outlet gas delivery point capacity – Alaska-Canada Border (Bcf/d)	4.370 – 4.570 (seasonal capacity)
Pipeline Segment Downstream Of The GTP - Valdez Pipeline	Pipeline diameter (inches)	48
	Pipeline grade	X80
	Pipeline length – Alaska (miles)	803
	Pipe capacity (base design – Bcf/d)	3.0
	Pipe capacity (with max compression – Bcf/d)	As per future requirements
	Inlet gas receipt temperature (°F)	< 30
	Minimum Design outlet gas delivery temperature (°F)	26
	Outlet gas delivery point capacity - Livengood (MMcf/d)	No less than the In-State Needs Study value of 9
	Outlet gas delivery point capacity - Fairbanks (MMcf/d)	No less than the In-State Needs Study value of 55
	Outlet gas delivery point capacity - Delta Junction Area/Richardson Highway Spur (MMcf/d)	No less than the In-State Needs Study value of 1.4

Table 2: Proposed Size and Design Capacities (Continued)

Section Of The Proposed Project	Design Parameter	Value
Pipeline Segment Downstream Of The GTP - Valdez Pipeline	Outlet gas delivery point capacity – Parks Highway Spur (MMcf/d)	Included in Fairbanks capacity
	Outlet gas delivery point capacity - Glennallen (MMcf/d)	No less than the In-State Needs Study value of 270
	Outlet gas delivery point capacity – Valdez (MMcf/d)	No less than the In-State Needs Study value of 7
	Outlet gas delivery point capacity - Valdez LNG Terminal (Bcf/d)	2.775

Designs for Initial and Possible Expanded Capacity

1. The gas transmission pipeline segment between the outlet of the Point Thomson plant and the inlet of the GTP consists of a single 32-inch pipeline traversing a distance of approximately 58 miles with a base case capacity of 1.1 Bcf/d and a maximum operating pressure of 1130 psig. A system capacity of 1.5 Bcf/d could be accommodated by designing to a higher maximum operating pressure. The pipeline system will be designed to maintain flowing gas temperatures below 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. Base case design assumes that gas will be delivered to the GTP at 670 psig.

2. The gas transmission pipeline segment between the outlet of the GTP and Boundary Lake (Alaska-Canada Pipeline and Canadian Pipeline) consists of a single 48-inch pipeline traversing a distance of approximately 1700 miles (734 miles in Alaska and 966 miles in Canada). The base capacity assumes that 4.5 Bcf/d will be received into the pipeline at the outlet of the GTP and that 0.336 Bcf/d of this throughput will be delivered at various locations within the state. For this system, 17 compressor stations will be installed on the pipeline system (6 in Alaska and 11 in Canada). With additional compression, pipeline capacity is expandable to 5.9 Bcf/d. The maximum operating pressure will be 2500 psig. From the outlet of the GTP to a location approximately 867 miles downstream, the pipeline system will be designed to maintain flowing gas temperatures at 32°F or lower. The remainder of the pipeline system to the Alberta border will be designed to generally maintain flowing gas temperatures above 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. The delivery pressure at the Alberta border will be approximately 1225 psig.

3. The gas transmission pipeline segment from the outlet of the GTP to the LNG terminal facilities near Valdez (i.e. the Valdez Pipeline) consists of a single 48-inch pipeline traversing a distance of approximately 803 miles. Base case capacity assumes that 3.0 Bcf/d will be received into the pipeline at the outlet of the GTP and 0.342 Bcf/d will be delivered at various locations within the state. For this case, two compressor stations will be installed. Pipeline capacity is expandable with additional compression. The maximum operating pressure will be 2500 psig. From the outlet of the GTP to a location approximately 730 miles downstream, the pipeline system will be designed to maintain flowing gas temperatures at 32°F or lower. The remainder of the pipeline system to the LNG terminal will be designed to generally maintain flowing gas temperatures above 32°F. Maintaining these gas temperatures recognizes the presence of permafrost soils along the route and will support stable operation from a geotechnical perspective. The delivery pressure at the LNG terminal is designed to be approximately 900 psig.

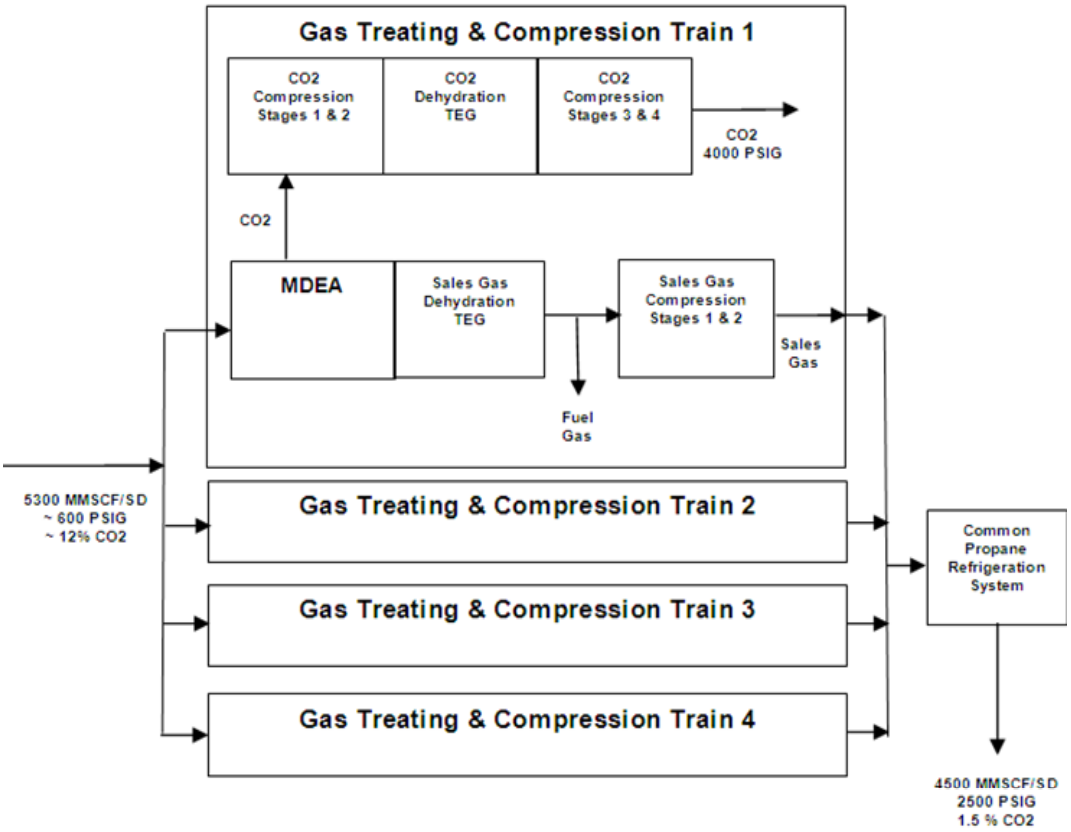
4. The GTP will be designed to handle raw gas with an inlet pressure of about 600 psi, and an average inlet temperature of 60°F, and can be expanded to treat additional gas. It will operate in conjunction with and is necessary to deliver pipeline quality gas into either the Alaska-Canada Pipeline or the Valdez Pipeline. Shippers will be required to meet the gas quality specifications in TC Alaska's FERC Gas Tariff, attached as Exhibit I to Appendix C, but will not be required to have their gas treated at the GTP. The outlet sales gas from the GTP will have a pressure and temperature of approximately 2500 psi and 30°F respectively.

    - The proposed GTP design for the Alaska-Canada Pipeline will treat approximately 5.3 Bcf/d of inlet gas, and deliver approximately 4.5 Bcf/d of pipeline quality gas with a CO_2 content between 1.5% and 2%. The GTP is expected to remove approximately 0.6 Bcf/d of acid gas and consume approximately 0.2 Bcf/d of fuel gas.

    - The GTP design for the Valdez Pipeline will treat approximately 3.6 Bcf/d of inlet gas, and deliver approximately 3.0 Bcf/d of pipeline quality gas with a CO_2 content of ≤50 ppm. The GTP is expected to remove approximately 0.44 Bcf/d of acid gas and consume approximately 0.17 Bcf/d of fuel gas.

    Figure 2 summarizes the GTP design configuration.

Figure 2: Simplified Block Flow Diagram of Gas Treating Trains



5. APP will assess the market demand for additional capacity every two years through public nonbinding solicitations or similar means. Based on the results of the current and future Open Seasons, APP will add capacity to accommodate demonstrated market needs unless such needs cannot be accomodated due to economic, engineering, design, capacity, or operational constraints, or unless the addition of capacity would adversely impact the timely development of the Project.

   APP will first make use of compression to add capacity, consistent with the requirements of the Alaska Gasline Inducement Act ("AGIA"). As the use of additional compression was preplanned in the initial design, such expansions will be relatively inexpensive and will be considered ahead of other options such as looping. To achieve the capacity addition, the use of more compressor stations and line heaters will be needed.

   Without expansion, the initial Alaska-Canada Pipeline and Canadian Pipeline design makes use of up to 17 compressor stations – 7 chilled and 10 unchilled. Of the 7 chilled, 6 are planned for Alaska and 1 in the Yukon, spaced roughly at equal intervals along the pipeline. The design is for Arctic service and suitable for installation on permafrost. The 10 unchilled compressor stations will be all located in Canada and also spaced at roughly equal intervals along the pipeline. One of the 10 will be a double unit station.

The initial pipeline design also includes 3 heater stations, 1 in the Yukon and 2 in British Columbia. A seasonal variation in duty at these heater stations is anticipated and the typical design uses four 20 million Btu/h line heaters.

By adding 16 intermediate compressor stations, the pipeline capability is expandable to approximately 5.9 Bcf/d. Of these 16 intermediate stations, 8 will be chilled stations - 7 in Alaska and 1 in the Yukon. The remaining 8 unchilled stations will be in Canada and 1 of these will be a two unit station.

This expanded design will therefore make use of a total of 33 stations - 15 chilled and 18 unchilled. Of the unchilled, 10 stations will require aerial coolers to control the temperature - 5 of the original stations and 5 of the incremental stations. For the 5.9 Bcf/d volume, two additional line heaters will also be required at an existing British Columbia site. As with the Alaska-Canada pipeline design, the Valdez pipeline may also make use of additional compressors and heaters for future expansion.

The GTP capacity can be expanded by approximately 0.45 Bcf/d by debottlenecking the gas treating trains. Helper motors will be required for both the sales gas and CO_2 compressors as well as for additional plant processing loads. An additional 80,000 BHP is envisioned for this expansion scenario and necessitates the addition of a fifth turbine power generator rated at about 73 MW or 100,000 BHP.

More significant GTP capacity expansion of approximately 1.125 Bcf/d is available through the addition of a gas treatment train, which would be comprised of acid gas removal, dehydration, sales gas compression and CO_2 compression equipment. The utilities and infrastructure (sales gas chilling, heat medium, flares/vents, water treatment, etc.) will also be required to be expanded in order to support the additional train. To supply the additional sales gas chilling refrigeration power load, an additional turbine power generator is anticipated to be required for this alternative also.

Item 3 - Operating Pressures

18 C.F.R. §157.34(c)(3): Maximum allowable operating pressure and expected actual operating pressure;

Maximum allowable operating pressures and actual operating pressures are summarized in Table 3 below.

Table 3: Expected Maximum Allowable And Expected Operating Pressures

Section Of Proposed Project	Location	Maximum Allowable Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Point Thomson Pipeline	Gas inlet	1130	1030
	Gas outlet	1130	670
GTP For The Alaska-Canada Pipeline	Gas inlet	705	600
	Gas outlet (treated gas)	2500	2450
	CO_2 outlet	4380	4000
GTP For The Valdez Pipeline	Gas inlet	705	600
	Gas outlet (treated gas)	2500	2450
	CO_2 outlet	4380	4000
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Gas inlet (from the GTP and Other points as required)	2500	2450
	Outlet gas delivery point – Livengood	2500	2160
	Outlet gas delivery point – Fairbanks	2500	2296
	Outlet gas delivery point – Parks Highway Spur	2500	2296
	Outlet gas delivery point – Delta Junction/Richardson Highway Spur	2500	2397

Table 3: Expected Maximum Allowable And Expected Operating Pressures (Continued)

Section Of Proposed Project	Location	Maximum Allowable Operating Pressure (psig)	Expected Actual Operating Pressure (psig)
Pipeline Segment Downstream Of The GTP - Alaska-Canada Pipeline	Outlet gas delivery point – Tok	2500	2412
	Outlet gas delivery point – Alaska-Canada Border	2500	2053
Pipeline Segment Downstream Of The GTP – Valdez Pipeline	Gas inlet (from the GTP and Other points as required)	2500	2450
	Outlet gas delivery point – Livengood	2500	2131
	Outlet gas delivery point – Fairbanks	2500	1979
	Outlet gas delivery point – Parks Highway Spur	2500	1979
	Outlet gas delivery point – Delta Junction/Richardson Highway Spur	2500	1771
	Outlet gas delivery point – Glennallen	2500	1312
	Outlet gas delivery point – Valdez	2500	950
	Outlet gas delivery point – Valdez LNG Terminal	2500	900

Item 4 - Delivery Pressures

18 C.F.R. §157.34(c)(4): Delivery pressure at all delivery points named in (1) above;

Delivery pressures for all proposed delivery points are summarized in Table 4 below.

Table 4: Proposed Delivery Pressures

Section	Delivery Point	Pressure (pisg)
Point Thomson Pipeline	Gas to GTP inlet	600
GTP – For The Alaska-Canada Pipeline	Outlet Gas (to pipeline)	2450
	CO_2 outlet	4000
GTP – For The Valdez Pipeline	Outlet Gas (to pipeline)	2450
	CO_2 outlet	4000
Pipeline Downstream Of The GTP - Alaska-Canada Pipeline	Livengood	2160
	Fairbanks	2296
	Parks Highway Spur	2296
	Delta Junction/Richardson Highway Spur	2397
	Tok	2412
	Alaska-Canada Border	2053
Pipeline Downstream Of The GTP - Valdez Pipeline	Livengood	2131
	Fairbanks	1979
	Parks Highway Spur	1979
	Delta Junction/Richardson Highway Spur	1771
	Glennallen	1312

Table 4: Proposed Delivery Pressures (Continued)

Section	Delivery Point	Pressure (pisg)
Pipeline Downstream Of The GTP - Valdez Pipeline	Valdez	950
	Valdez LNG Terminal	900

Item 5 - In-Service Date

18 C.F.R. §157.34(c)(5): Projected in-service date;

The estimated in-service date for the Alaska-Canada Pipeline and the Valdez Pipeline is 2020 for initial gas and 2021 for full gas.

Item 6 - Transportation And Treating Rates

18 C.F.R. §157.34(c)(6): An estimated unbundled transportation rate for each delivery point named in (1) above, stated on a volumetric or thermal basis, for each service offered, including reservation rates for pipeline capacity, interruptible transportation rates, usage rates, fuel retention percentages, and other applicable charges, or surcharges, such as ACA; (if rates are estimated on a volumetric basis then the notice must inform bidders that final pro forma service agreements and the sponsor's proposed FERC tariff will have to be submitted with rates based on a thermal basis.)

Rates shown below are for a 25-year recourse rate firm transportation and gas treatment contract. The derivation of the rates is explained in Item 7. Additional information is provided in Exhibits J and K.

Rates are established by Zones as follows:

Zone 1: Comprising Transporter's facilities from the Point Thomson plant outlet to the inlet of the GTP, with a receipt point at Point Thomson and delivery points at or near the inlet of the GTP.

Zone 2: Comprising the GTP, providing firm gas treatment service, with a receipt point at the GTP inlet and a delivery point at the GTP outlet into Zone 3 of Transporter's facilities.

Zone 3 – Alaska-Canada Pipeline Alternative: Comprising the pipeline downstream of the outlet of the GTP and proceeding to the Alaska-Canada border, with a receipt point or points downstream of the GTP and delivery points at points within Alaska (In-State Delivery) and at the Alaska-Canada border (Export Delivery) for further transport on the Canadian Pipeline.

Zone 3 – Valdez Pipeline Alternative: Comprising the pipeline downstream of the outlet of the GTP and proceeding to near Valdez, with a receipt point or points downstream of the GTP and delivery points at points within Alaska (In-State Delivery) and at the LNG liquefaction facility at Valdez (Export Delivery).

ESTIMATE OF RECOURSE RATES

Rate Schedule	Base Tariff Rate Range	
	Alaska-Canada Pipeline	Valdez Pipeline
FT-1		
Zone 1: Point Thomson		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$8.45 - $11.19	$8.43 - $11.07
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$0.28 - $0.37	$0.28 - $0.36
Zone 2: GTP		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$57.62 - $74.72	$73.02 - $93.66
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$1.89 - $2.46	$2.40 - $3.08
Zone 3: In-State Delivery		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$29.28 - $38.72	$55.11 - $72.35
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$0.96 - $1.27	$1.81 - $2.38
Zone 3: Export Delivery		
Monthly Reservation Rate (per MMBtu of contractual entitlements)		
Maximum	$40.91 - $54.10	$63.18 - $82.95
Minimum	$0.00	$0.00
Commodity Rate (per MMBtu)		
Maximum	$0.00	$0.00
Minimum	$0.00	$0.00
AOS Commodity Rate	$1.35 - $1.78	$2.08 - $2.73

ESTIMATE OF RECOURSE RATES

Rate Schedule	Base Tariff Rate Range	
	Alaska-Canada Pipeline	**Valdez Pipeline**
IT-1		
Zone 1: Point Thomson		
Commodity Rate (per MMBtu)		
Maximum	$0.28 - $0.37	$0.28 - $0.36
Minimum	$0.00	$0.00
Zone 2: GTP		
Commodity Rate (per MMBtu)		
Maximum	$1.89 - $2.46	$2.40 - $3.08
Minimum	$0.00	$0.00
Zone 3: In-State Delivery		
Commodity Rate (per MMBtu)		
Maximum	$0.96 - $1.27	$1.81 - $2.38
Minimum	$0.00	$0.00
Zone 3: Export Delivery		
Commodity Rate (per MMBtu)		
Maximum	$1.35 - $1.78	$2.08 - $2.73
Minimum	$0.00	$0.00
PAL		
Daily Maximum Commodity Rate per MMBtu	$1.35 - $1.78	$2.08 - $2.73
Daily Minimum Commodity Rate per MMBtu	$0.00	$0.00

Surcharges Rate per MMBtu	**Alaska-Canada Pipeline**	**Valdez Pipeline**
Annual Charge Adjustment (ACA) Rate	$0.0019	$0.0019
Change in Law/Tax/Regulation Surcharge	$0.0000	$0.0000

Fuel (%)	**Alaska-Canada Pipeline**	**Valdez Pipeline**
Zone 1: Point Thomson	0.25	0.25
Zone 2: GTP	4.50	5.70
Zone 3: In-State Delivery	0.80	0.40
Zone 3: Export Delivery	1.00	0.80

Item 7 - Cost Of Service

18 C.F.R. §157.34(c)(7): The estimated cost of service (i.e., estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses), and estimated cost allocations, rate design volumes and rate design;

The APP estimated cost of facilities, depreciation, rate of return and capitalization, taxes and operational and maintenance expenses are identified in Exhibits J and K. The cost of service underlying the recourse rates for the Alaska-Canada Pipeline and Valdez Pipeline has been derived using a 4% straight line depreciation rate, a return on equity equal to the 10 year U.S. Treasury Note rate plus 965 basis points, adjusted annually (for illustrative rate purposes assumed to be 14%), a capital structure of 70% debt and 30% equity, estimated operating costs and property taxes, a negative salvage allowance, and corporate income tax rates, utilizing principles of tax normalization.

Cost allocation and rate design volumes are reflected in Exhibits J and K. For cost allocation purposes, APP has utilized the costs contained in or associated with each Zone for developing rates applicable to gas transportation in Zones 1 and 3 and gas treatment service in Zone 2. For illustrative rate design purposes only, Exhibits J and K utilize billing determinants of 1.1 Bcf/d for Zone 1, and for Zones 2 and 3 utilize billing determinants of 4.5 Bcf/d for the Alaska-Canada Pipeline and 3.0 Bcf/d for the Valdez Pipeline. Recourse rates will be designed using billing determinants equal to contracted capacities under non-defaulting contracts. Firm transportation and firm gas treatment reservation rates are designed using the straight fixed-variable methodology. AOS, IT, and PAL rates are designed on a 100% load factor basis. The methodology for deriving rates for deliveries within Alaska is described in Item 8.

Item 8 - In-State Transportation Rates

18 C.F.R. §157.34(c)(8): Based on the In-State Study and the delivery points within the State of Alaska identified in (1) above, there must be an estimated transportation rate for such deliveries, based on the amount of in-state needs shown in the study. Such estimated transportation rate must be based on the costs to make such in-state deliveries and shall not include costs to make deliveries outside the State of Alaska;

A single in-state rate will be developed for all in-state delivery points. The estimated rates for the Alaska-Canada Pipeline and the Valdez Pipeline are shown in Exhibits J and K. The volumes from the *In-State Gas Demand Study* on which those estimated rates are based are shown in Table 5 below.

The estimated rate for in-state deliveries has been developed utilizing a weighted average volume-mile cost allocation and rate design methodology as indicated below.

APP computed aggregate in-state volume-miles by adding the products of

1. the estimated MDQ for each delivery point, as derived from the *In-State Gas Demand Study* and,

2. the miles from the outlet of the GTP to each delivery point.

The resulting sum of in-state volume-miles was then divided by the total volume-miles (similarly computed) associated with firm transportation contracts for all deliveries either within the state or to to the Alaska-Canada border or to the Valdez LNG facility. The resulting percentage was then applied to the total cost of service to determine the costs applicable to in-state deliveries.

The costs applicable to in-state deliveries were then used to design in-state rates, by dividing such costs by in-state aggregate MDQs.

Table 5: Estimated In-State Volumes (Based On In-State Needs Study)

Location	**Alaska-Canada Pipeline Route (MMcf/d)**	**Valdez Pipeline Route (MMcf/d)**
Livengood	9	9
Fairbanks	55	55
Parks Highway spur	Alternative to Delta Junction	-
Delta Junction area/Richardson Highway spur	272	1.4

Table 5: Estimated In-State Volumes (Based On In-State Needs Study)(Continued)

Location	Alaska-Canada Pipeline Route (MMcf/d)	Valdez Pipeline Route (MMcf/d)
Tok	0.4	n/a
Glennallen	n/a	270
Valdez	n/a	7

Item 9 - Negotiated And Other Rates

18 C.F.R. §157.34(c)(9): Negotiated rate and other rate options under consideration, including any rate amounts and terms of any precedent agreements with prospective anchor shippers that have been negotiated or agreed to outside of the open season process proscribed herein;

In this Open Season, APP is offering shippers the option of negotiated rates, which shall be paid without regard to any action or determination of the FERC with respect to recourse rates. APP has not entered into any precedent agreements with prospective shippers outside this Open Season.

The negotiated rates being offered will be computed and paid in accordance with the principles and process specified in Exhibit A to the proposed Precedent Agreement (Appendix A to Open Season Notice). Additional information is provided in Exhibits J and K to this Appendix C.

The negotiated rate principles from Exhibit A of the Precedent Agreement are as follows:

Negotiated rates shall be based upon, and the Parties intend that they will recover, Transporter's costs as identified in items 1-12 below. The Parties agree that negotiated rates shall be recalculated annually in order to assure that Transporter's rates recover all costs of providing service. The Parties further agree to utilize the following process to revise negotiated rates. On each November 1st following at least 15 months after the Commencement Date, Transporter shall circulate schedules and work papers to all Shippers electing negotiated rates which identify (i) Transporter's cost of service and normalized billing determinants for the twelve months ending the preceding August 31st determined in accordance with the negotiated rate principles set forth below, and (ii) Transporter's revenues collected during such twelve month period, net of any credits or applicable adjustments during such period. Transporter shall also identify revised negotiated rates to be effective beginning January 1st of the following year which shall be based upon the cost of service and normalized billing determinants identified above, adjusted for any difference (positive or negative) between costs and revenues, net of any credits or applicable adjustments, during the twelve month period identified in (i) above. Adjustments in normalized billing determinants shall be made separately by zone if necessary to recognize different levels of service or service interruption by zone.

Transporter and all Shippers electing negotiated rates shall meet to discuss the cost of service, billing determinants, schedules, work papers and proposed negotiated rates. Transporter will then file at FERC such negotiated rates, or such other rates which Transporter agrees to file, no later than December 31st and request that the negotiated rates be made effective January 1st. In the event Shipper objects to Transporter's filed negotiated rates, the matter shall be subject to the Dispute Resolution provisions of Transporter's Tariff. If the award of the arbitral Tribunal determines that Shipper's negotiated rates should be lower than the rates in effect for any applicable period, Transporter shall refund the difference between such lower rates and the rates charged, including interest at the applicable FERC rate.

Negotiated firm transportation reservation rates will be stated on an MMBtu (thermal) basis to provide for recovery by the Transporter of all fixed costs of providing firm transportation service. Shipper will also pay a commodity or usage charge for MMBtus actually transported, and provide volumes for Fuel. The negotiated firm reservation rate for gas treatment services will be calculated and stated on an MMBtu basis to provide for recovery by Transporter of all fixed

costs of providing firm gas treatment services at Transporter's GTP. Shippers will also pay commodity charges per MMBtu and provide volumes for Fuel, as applicable, for gas treatment services.

The major elements in determining the cost of service and the methodology for the rate design of negotiated rates, are set forth below.

1. Upon the approval of the final costs by FERC, the target capital structure will be 75% debt and 25% equity. The final capital structure used for setting the negotiated rates shall be equal to Transporter's actual capital structure, provided that the capital structure utilized in determining negotiated rates shall include no less than 25% equity and be subject to A.S. 43.90.130(10), as amended from time to time. For expansions and maintenance capital, the capital structure for rate making purposes shall be 70% debt and 30% equity.

2. The actual weighted average cost of Transporter's debt will be calculated using an interest rate equal to the weighted average of the interest rate(s) on such debt. Any payments made to secure or reduce the cost of debt financing will be added to rate base. Changes in the actual weighted average cost of Transporter's debt will be reflected in negotiated rates for the Initial Service Term and any extension of the initial term of the FTSA.

3. Rate of return on equity will be 12% on an after-tax basis.

4. Income taxes will be calculated on a normalized basis, utilizing the federal and state corporate income tax rates for the Initial Service Term and any extension of the initial term of the FTSA. Changes in the federal and state corporate income tax rates will be reflected in the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

5. For the Initial Service Term and any extension of that term, depreciation on the GTP and transmission plant used for purposes of deriving rates will be calculated annually. An FTSA with an Initial Service Term of 20 to 25 years will recover 80% of the Shipper's Proportional Share of capital costs approved by FERC for Recourse Rates, and allowance for funds used during construction ("AFUDC") and property tax paid during construction ("Approved Capital Costs"), during the Initial Service Term, with Shipper's Proportional Share defined as an amount equal to Shipper's MDQ divided by aggregate MDQs, as adjusted to reflect firm shipper defaults and incremental transportation service from initial capacity. Such Shipper's Proportional Share of the remaining 20% of Approved Capital Costs shall be recovered in an additional period of five years following the Initial Service Term, utilizing the assumption that all non-defaulting firm shippers with Initial Service Terms of 20 years or more elect to renew. An FTSA with an Initial Service Term exceeding 25 years shall recover 80% of Shipper's Proportional Share of Approved Capital Costs in the first 25 years of that Term, and such Shipper's Proportional Share of the remaining 20% of Approved Capital Costs shall be recovered over the balance of the Initial Service Term.

6. Rates will include a reasonable estimate of negative salvage costs to fund the net costs of abandoning the APP U.S. Facilities and restoring the affected properties at the end of the system's service life. Changes in the negative salvage costs will be reflected in the

revenue requirement of the negotiated rate for the Initial Service Term and any extension of the initial term of the FTSA.

7. The rate base will include, among other things, (i) debt service reserve, (ii) cost of line pack, inventory, and spare parts, (iii) payments made to secure or reduce the cost of debt financing, (iv) working capital up to one-twelfth of annual operating expenses, (v) prepayments, and (vi) Approved Capital Costs utilizing the weighted average cost of debt in principle No. 2 and the 12% return on equity, and be reduced by the cumulative depreciation and cost reimbursement received pursuant to the Alaska Gasline Inducement Act ("AGIA").

8. The negotiated reservation rates will be calculated based upon billing determinants equal to the sum of all firm contracted capacities under non-defaulting service agreements, normalized for any billing determinants attributable to in-state rates designed on a distance basis and adjusted for any reductions associated with service disruptions or changes in Shippers' MDQ or MTQ, for both the Initial Service Term and any extension of that term.

9. During the Initial Service Term and any extension of that term,

   (a) Shipper shall continue to pay full reservation charges during any period of reduction of firm transportation service or firm gas treatment service, including an Interruption; provided that, reservation charges during a GTP Turnaround or Phase-In Period will be charged with respect to a reduced capacity for firm gas treatment and firm gas transportation services;

   (b) There will be a commodity or usage charge which will recover costs which vary with volumes actually shipped (the commodity charge is estimated to be minimal);

   (c) Fuel will be recovered on the basis of actual quantities of fuel consumed or utilized in operations and fuel lost and unaccounted for;

   (d) Rates will reflect changes in Transporter's taxes (other than income taxes), fees assessed by any governmental entity, and all other operating costs;

   (e) In addition to changes reflected elsewhere in these rate principles, negotiated rates will reflect changes in (i) billing determinants reflecting contracted capacities and (ii) rate base;

   (f) Transporter will credit to Shipper and other shippers that have secured firm transportation service, on a pro rata basis according to firm transportation shippers' MDQ, 75 percent of the revenue received by Transporter for the provision of AOS service, IT service, and PAL service.

10. Negotiated rates shall be adjusted to ensure that they are not inconsistent with A.S. 43.90.130(7)(A)-(D), as amended from time to time.

11. A Foundation Shipper shall be entitled to elect the same negotiated rate principles, in their entirety, as offered prior to the Commencement Date and accepted by any other shipper.

12. Negotiated rate shippers shall pay the recourse rate for AOS and any other non FT-1 service.

Item 10 - Quality Specifications

18 C.F.R. §157.34(c)(10): Quality specifications and any other requirements applicable to gas to be delivered to the project; provided that a prospective applicant shall not require that potential shippers process or treat their gas at any designated plant or facility;

The quality specifications and other requirements applicable to gas to be delivered to the Point Thomson Pipeline segment and GTP, and the downstream segments of the Alaska-Canada Pipeline and Valdez Pipeline are set forth in Section 5 of the General Terms and Conditions of TC Alaska's indicative FERC Gas Tariff, attached as Exhibit I to this Appendix. Potential shippers are not required to process or treat their gas at any designated plant or facility.

Item 11 - Terms And Conditions

18 C.F.R. §157.34(c)(11): Terms and conditions for each service offered;

TC Alaska's indicative FERC Gas Tariff, attached as Exhibit I to this Appendix, sets forth the terms and conditions for each service to be offered.

Item 12 - Creditworthiness Standards

18 C.F.R. §157.34(c)(12): Creditworthiness standards to be applied to, and any collateral requirements for, prospective shippers;

The APP creditworthiness requirements are set forth in Exhibit B to the proposed Precedent Agreement (Appendix A to Open Season Notice) and will be applicable to all shippers.

The creditworthiness standards apply for purposes of the Precedent Agreement, including Section III(c), Section IV(a)(4), and Section V(a) of the Precedent Agreement, and for evaluating requests for provision of service. Due to the requirements to finance a project of this magnitude, these creditworthiness standards shall continue to apply to shippers (or assignees) under the terms of the Firm Transportation Service Agreement ("FTSA") during the Initial Service Term and any extension of that term. TC Alaska shall not be required to continue to perform its obligations under the Precedent Agreement or an FTSA, or to commence or continue service, on behalf of any shipper that fails to establish and maintain creditworthiness. TC Alaska shall determine shipper's creditworthiness, at any time in its sole discretion, in accordance with Exhibit B of the Precedent Agreement.

Item 13 - Precedent Agreement Execution Date

18 C.F.R. §157.34(c)(13): The date, if any, by which potential shippers and the prospective applicant must execute precedent agreements;

Potential shippers must submit an executed Precedent Agreement in the form included in Appendix A of the Notice prior to the close of the Open Season. The final version of the Precedent Agreement shall be executed by successful bidders, TC Alaska and the APP Parties as described in the response to Item 16.

Item 14 - Bid Evaluation

18 C.F.R. §157.34(c)(14): A detailed methodology for determining the value of bids for deliveries within the State of Alaska and for deliveries outside the State of Alaska;

Due to the magnitude of this project and the associated financing requirement, APP will require a long-term firm commitment of 20 years or more from all bidders during this Open Season. Since bidders will be required to make a long-term firm commitment, APP will value all acceptable bids for firm transportation service received in this Open Season, whether for deliveries in the State of Alaska or deliveries outside the State of Alaska, on an equal basis. (See response to 18 C.F.R. §157.34(c)(15) for over-subscription allocation.)

Item 15 - Oversubscription Allocations

18 C.F.R. §157.34(c)(15): The methodology by which capacity will be awarded, in the case of over-subscription, clearly stating all terms that will be considered, except that if any capacity is acquired through pre-subscription agreements as provided in §157.33(b) and the prospective applicant does not redesign the project to accommodate all capacity requests, only that capacity that was acquired through pre-subscription or was bid in the open season on the same rates, terms, and conditions as any one of the pre-subscription agreements shall be allocated on a pro rata basis and no other capacity acquired through the open season shall be allocated;

The APP Parties intend to design the Project, within certain economic and engineering design increments, to accommodate all capacity requests on a not unduly discriminatory basis from conforming bids received during the Open Season.

However, in the event conforming bids received during the Open Season exceed the design capacity determined by APP, APP reserves the right to reduce the bidders' MDQs and MTQs indicated on Exhibit A to the Precedent Agreements pro rata based solely on each bidder's proportion of the total quantity of firm transportation capacity and firm treatment capacity reflected in conforming bids received by APP, without regard to whether a shipper would qualify as a Foundation Shipper, has selected recourse rates or negotiated rates, or has specified in-state or export deliveries.

In the event that a bidder's transportation MDQ in Zone 3 downstream of the GTP is reduced, as stated above, the bidder's Zone 2 MTQ will be reduced by a corresponding amount. In the event that a bidder's Zone 2 MTQ is reduced, as stated above, the bidder's transportation MDQ in Zone 3 downstream of the GTP will be reduced by a corresponding amount.

Bidders will have 30 days to either accept or reject such allocated quantity of capacity. If one or more bidders reject a reduced quantity of capacity, the original capacity requests of the remaining bidders may be restored.

Item 16 - Bid Requirements

18 C.F.R. §157.34(c)(16): Required bid information, whether bids are binding or non-binding, receipt and delivery point requirements, the form of a precedent agreement and time of execution of the precedent agreement, definition and treatment of non-conforming bids;

This Open Season is being held to solicit the submission and execution of binding Precedent Agreements (the form of which is attached as Appendix A to the Open Season Notice) for firm interstate natural gas transportation service and optional firm gas treatment service provided by TC Alaska's Alaska Pipeline Project.

A conforming bid for this Open Season shall consist of the following:

- A Precedent Agreement executed by an authorized representative of the bidding company for either or both of the Alaska-Canada Pipeline or the Valdez Pipeline in the form included in Appendix A to the Open Season Notice.

- A completed Exhibit A, including the following:

    - The Maximum Daily Quantity ("MDQ") and optional Maximum Treatment Quantity ("MTQ"), exclusive of Fuel, by requested primary receipt and delivery point(s)

    - Election of recourse rates or negotiated rates

    - Primary term of 20-25, 30 or 35 years for shippers selecting negotiated rates and 25 years for shippers selecting recourse rates

- Each bidder must return the completed Precedent Agreement before the end of the Open Season to APP at the address specified in the Precedent Agreement Submittal section of the Open Season Notice.

APP reserves the right to reject any bid that does not conform to the requirements stated above. Within five business days after the close of the Open Season, APP will notify each bidder whether they have submitted a conforming bid and will provide a written explanation to those bidders whose bids have been rejected as non-conforming.

APP recognizes that bidders may desire to include certain CPs to their bids and bidders will be allowed to negotiate CPs acceptable to the APP Parties prior to, during and after the close of the Open Season. APP reserves the right to reject, on a not unduly discriminatory basis, a conforming bid that includes CPs or modifications to the Precedent Agreement that are unacceptable to the APP Parties. At that time, APP will notify any bidder whose bid is rejected and provide a written explanation for the rejection.

Shippers who submit conforming bids will be notified by September 1, 2010, of the following:

- Whether APP will proceed to seek to design, permit and construct the Alaska-Canada Pipeline and GTP, or will proceed to seek to design, permit and construct the Valdez Pipeline and GTP and the total aggregated capacity from conforming bids for the selected route. Upon shippers' receipt of such notification, the shipper's service elections on Exhibit

A to the Precedent Agreement with respect to the pipeline alternative that is not selected for development are thereafter without effect and are not enforceable by the shipper or by TC Alaska.

- The APP Parties intend to design the Project within certain economic and engineering design increments, to accommodate all capacity requests on a not unduly discriminatory basis from conforming bids received during the Open Season. However, in the event conforming bids received during the Open Season exceed the design capacity determined by APP, APP reserves the right to reduce the bidders' MDQs and MTQs indicated on Exhibit A to the Precedent Agreements pro rata, based solely on each bidder's proportion of the total quantity of firm transportation capacity and firm treatment capacity reflected in conforming bids received by APP, without regard to whether a shipper would qualify as a Foundation Shipper, has selected recourse rates or negotiated rates, or has specified in-state or export deliveries. In the event that a bidder's transportation MDQ downstream of the GTP is reduced, as stated above, the bidder's MTQ will be reduced by a corresponding amount. In the event that a bidder's MTQ is reduced, as stated above, the bidder's transportation MDQ downstream of the GTP will be reduced by a corresponding amount. Bidders will have 30 days to either accept or reject such allocated quantity of capacity. If one or more bidders reject a reduced quantity of capacity, the original capacity requests of the remaining bidders may be restored.

On or before October 31, 2010, APP will notify conforming bidders of the impact on the Project of the total aggregated capacity from conforming bids for the selected route.

On or before November 30, 2010, APP will provide conforming bidders with the final version of the Precedent Agreement.

Following the final notification and following APP Parties' approval of each successful bidder's written evidence of creditworthiness, as stipulated in Exhibit B to the Precedent Agreement, each bidder shall execute the final version of the binding Precedent Agreement and secure all board approvals and internal authorizations necessary to undertake the obligations required by the Precedent Agreement by no later than December 31, 2010.

Within 30 days of receiving notification of the last of the board approvals and other necessary internal authorizations, and confirmation of execution of the final version of the Precedent Agreement, from all successful bidders, the APP Parties shall secure all board approvals and internal authorizations necessary to undertake the obligations required by the Precedent Agreements and will execute Precedent Agreements. Precedent Agreements shall not become binding until after the bidder, TC Alaska, and the APP Parties have secured all board approvals and internal authorizations necessary to undertake the obligations required by the Precedent Agreement, and the bidder and TC Alaska have executed the Precedent Agreement.

The Precedent Agreement will bind the bidder to execute a firm transportation service agreement ("FTSA") before Project construction commences, and will condition the provision of service on satisfaction or express waiver of the transporter conditions precedent stipulated in the Precedent Agreement.

Item 17 - Project Certificate Application Date

18 C.F.R. §157.34(c)(17): The projected date for filing an application with the Commission;

TC Alaska intends to file its certificate application by October 31, 2012.

Item 18 - Information Disclosures And Data Room Procedures

18 C.F.R. §157.34(c)(18): All information pertaining to the proposed service to be offered, projected pipeline capacity and design, proposed tariff provisions, and cost projections, made available to or in the hands of any potential shipper, including any affiliates of the project sponsor and any shippers with pre-subscribed capacity, prior to the issuance of the public notice of open season;

The Alaska Pipeline Project has established a series of data rooms to hold material supplemental to the information contained in the APP Open Season Notice itself.

The data rooms are available to potential shippers and certain other interested stakeholders as well as interested U.S., Canada, and State of Alaska regulatory agencies.

The data rooms contain the information that the Alaska Pipeline Project has in its possession relating to the proposed service being offered, projected pipeline design and capacity, the proposed tariff provisions, and cost projections. In addition, the data rooms contain the information that APP has made available to, or obtained from, any potential shipper, including affiliates of the APP Parties, prior to the issuance of the Open Season Notice.

Due to the commercially and competitively sensitive nature of the information, all information contained in the data rooms that is not in the public domain shall be treated as confidential information. Any person wishing to access such confidential information will be required to sign a confidentiality undertaking in the form attached hereto as Exhibit G and comply with the data room procedures, attached hereto as Exhibit H.

The data rooms are set up on a hierarchical basis, as follows:

- All data room information in the public domain is accessible through APP's internet website, www.thealaskapipelineproject.com, and available for review by anyone interested in accessing that data.

- Data contained in the physical data rooms are broken into three levels of confidentiality.

    - The first level ("Tier 1") contains confidential project information, not in the public domain, but which is of relatively lower commercial and competitive risk to the Project. All interested stakeholders granted access to the data rooms will have access to Tier 1 data.

    - The second level ("Tier 2") contains high risk, commercially sensitive data, such as project component cost projections, land access cost projections and the like. Such information will be made available only to potential shippers and regulatory agencies with Project oversight responsibilities.

    - In addition, certain information ("Tier 3") contained in the data rooms is subject to third party confidentiality restrictions. Anyone seeking access to Tier 3 data will need to secure a release from such third parties in order to view such Tier 3 data.

The data rooms are located in the following locations:

- Houston, Texas – Main data room containing all required project information in electronic format or hard copy.
- Anchorage, Alaska – Adjunct data room containing all required information available in electronic format.
- Whitehorse, Yukon – Adjunct data room containing all required information available in electronic format.
- Calgary, Alberta – Adjunct data room containing all required information available in electronic format.

Item 19 - Applicant Affiliates

18 C.F.R. §157.34(c)(19): A list of the names and addresses of the prospective applicant's affiliated sales and marketing units and affiliates involved in the production of natural gas in the State of Alaska. Affiliated unit means "Affiliate" as defined in § 358.3(a) of this chapter. Marketing units and or affiliates are those conducting a "marketing function" as defined in section 358.3 (c) of this chapter, except that the exemption in 358.3(c)(2)(iii) shall not apply;

The project applicant is TransCanada Alaska Company, LLC ("TC Alaska"). TC Alaska has no divisions or business operations other than the Alaska Pipeline Project. Neither TC Alaska nor its parent, TransCanada Corporation, has any affiliates involved in the production of natural gas in the State of Alaska. Within TransCanada, the following affiliates conduct a marketing function as defined in §358.3(c) of the Commission's regulations:

TransCanada Energy Ltd.
450 - 1st Street S.W.
Calgary, Alberta
T2P 5H1

TC Gas Services LLC
c/o Corporation Trust Company
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware, 19801

TC Ravenswood, LLC
c/o CT Corporation System
111 Eighth Avenue
New York, NY 10011

TransCanada Gas Storage USA, Inc.
c/o Corporation Trust Company
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware, 19801

TransCanada Power Marketing Ltd.
c/o Corporation Trust Company
Corporation Trust Center
1209 Orange Street
Wilmington, Delaware, 19801

The aforementioned TransCanada affiliates are presently not engaged in the marketing or sales of natural gas from Alaska and do not plan to be submitting bids for capacity or negotiating precedent agreements with APP or any other potential Alaska natural gas transportation project.

As a participant in the Alaska Pipeline Project, ExxonMobil provides below the names and addresses of its affiliated sales and marketing unit and its affiliates involved in the production of natural gas in the State of Alaska:

ExxonMobil Gas and Power Marketing Company ("EMGPM")
a division of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

EMGPM has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the commercialization of natural gas and related products and electric power in all parts of the world. Within EMGPM, the Americas unit has the aforementioned responsibilities for natural gas and related products and conducts a marketing function as defined in §358.3(c)(2) of the Commission's regulations, including the submission of bids for capacity and negotiation of precedent agreements on APP or other potential Alaska gas transportation projects.

ExxonMobil Production Company ("EMPC")
a division of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

EMPC has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the production and processing of petroleum and natural gas in all parts of the world. Within EMPC, the Americas unit has the aforementioned responsibilities in the State of Alaska and is engaged in activities related to the submission of bids for capacity and negotiation of precedent agreements on APP or other potential Alaska natural gas transportation projects.

ExxonMobil Development Company ("EMDC")
a wholly-owned subsidiary of Exxon Mobil Corporation
5 Greenspoint Plaza
17001 Northchase Dr.
Houston, TX 77060

EMDC has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the development of facilities required for the production and processing of petroleum and natural gas in all parts of the world. Within EMDC, the Arctic unit has the aforementioned responsibilities for the development of the Point Thomson field, support activities related to the Prudhoe Bay Unit and for other related upstream production activities in the State of Alaska.

Additionally, listed below are the names and addresses of four ExxonMobil entities that own or control mineral leases providing the rights to produce and process petroleum and natural gas from lands located in the State of Alaska. In each instance, the day to day stewardship of these mineral leases is the responsibility of the EMPC Americas Unit.

Exxon Mobil Corporation
5959 Las Colinas Blvd.
Irving, TX 75039

ExxonMobil Oil Corporation (“EMOC”)
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
5959 Las Colinas Blvd.
Irving, TX 75039

ExxonMobil Alaska Production Inc. (“EMAP”)
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

Mobil Exploration and Producing North America Inc. (“MEPNA”)
an indirect wholly-owned subsidiary of Exxon Mobil Corporation
800 Bell Street
Houston, TX 77002

Item 20 - Organization Charts

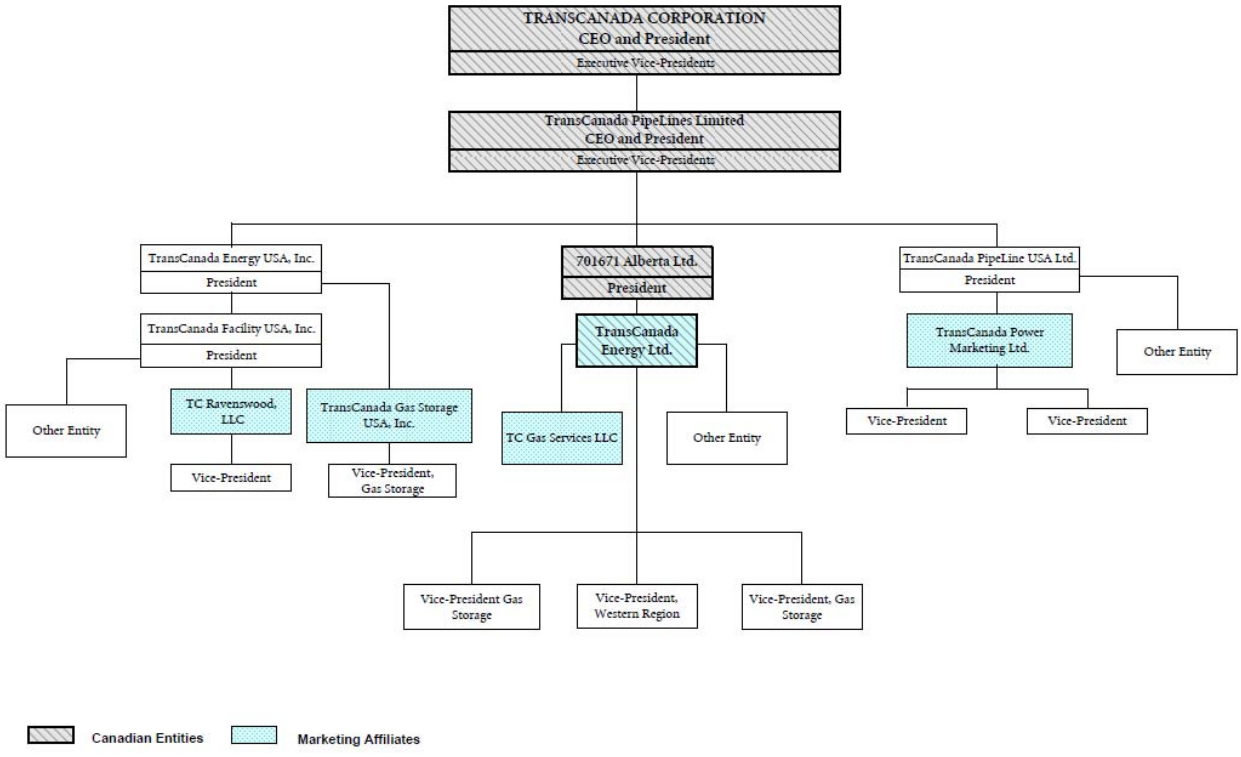
18 C.F.R. §157.34(c)(20): A comprehensive organizational chart showing:

(i) The organizational structure of the prospective applicant's parent corporation(s) with the relative position in the corporate structure of marketing and sales units and any affiliates involved in the production of natural gas in the State of Alaska.

(ii) The job titles and descriptions, and chain of command for all officers and directors of the prospective applicant's marketing and sales units and any affiliates involved in the production of natural gas in the State of Alaska;

As the parent company of the applicant TC Alaska, TransCanada Corporation provides below (see Figure 3a) an organizational chart illustrating the relevant portion of TransCanada's corporate structure and the relative position and reporting relationships (i.e. chain of command) within said structure of the affiliated sales and marketing units that conduct a marketing function as defined in §358.3(c) of the Commission's regulations. There are no affiliates of TransCanada Corporation involved in the production of natural gas in the State of Alaska.

Figure 3a: TransCanada Corporation and Affiliated Companies



The job titles and descriptions for those positions with day-to-day responsibility for the business activities of TransCanada Corporation's affiliated sales and marketing units that conduct a

marketing function as defined in §358.3(c) of the Commission's regulations are listed below. The relative position and reporting relationship for these positions is shown on the aforementioned organizational chart.

1. TransCanada Energy Ltd. ("TCE")

Vice-President, Gas Storage This position is responsible for management of the Alberta based gas storage business line as well as other market based storage activities. This includes oversight of gas storage marketing and trading functions as well as new business development initiatives for TCE.

Vice-President, Gas Storage This position is responsible for all aspects of TCE's trading and marketing for its Alberta based gas storage business.

Vice-President, Western Region This position is responsible for the commercial operations of TCE's Western Power business, including marketing and trading activities, commercial contracts and operations, and regulatory responsibilities.

2. TC Gas Services LLC ("TCGS")

TCGS holds outstanding transportation arrangements with one of TransCanada's transmission providers, but is otherwise an inactive entity. To the extent any services are required under the transportation arrangements these are performed on behalf of TCGS by its parent, TransCanada Energy Ltd.

3. TC Ravenswood, LLC ("Ravenswood")

Vice-President This position is responsible for the day-to-day operations of Ravenswood at the regional level, which include managing staff, setting strategy and operational planning for the business activity of Ravenswood and addressing policy actions Ravenswood may take before industry stakeholders and regulators. The position is also responsible for risk management activities relating to the business activity of Ravenswood (i.e. commodity market trading) and vetting the accuracy of reporting related to the same, along with financial results.

4. TransCanada Gas Storage USA, Inc. ("TC Gas Storage USA")

Vice-President, Gas Storage This position is responsible for management of the gas storage business line as well as other market based storage activities. This includes oversight of gas storage marketing and trading functions as well as new business development initiatives relating to TC Gas Storage USA.

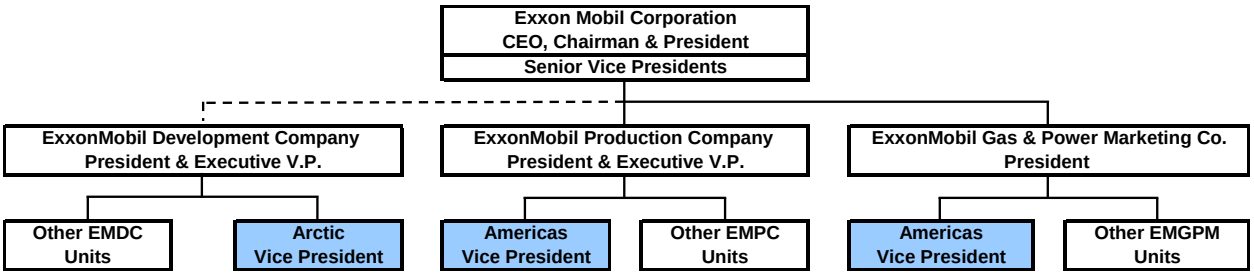
5. TransCanada Power Marketing Ltd. ("TCPM")

Vice-President This position is responsible for managing staff, setting strategy and operational planning for the business activity of TCPM and addressing policy actions TCPM may take before industry stakeholders and regulators. The position is also responsible for risk management activities relating to the business activity of TCPM (i.e. commodity market trading) and vetting the accuracy of reporting related to the same, along with financial results.

Vice-President This position is responsible for TCPM's regional regulatory and legislative affairs, retail marketing, and property taxes.

As the parent company of the ExxonMobil unit participating in the Alaska Pipeline Project, Exxon Mobil Corporation provides below (see Figure 3b) an organizational chart illustrating the relevant portion of ExxonMobil's corporate structure and the relative position and reporting relationships (i.e. chain of command) within said structure of the affiliates involved in the production of natural gas in the State of Alaska and the affiliated sales and marketing unit that conducts a marketing function as defined in §358.3(c)(2) of the Commission's regulations (highlighted in blue).

Figure 3b: Exxon Mobil Corporation and Affiliated Companies



Note: Dashed lines represent Functional guidance / stewardship / service relationships

Exxon Mobil Corporation and its affiliated companies are organized functionally, with day-to-day responsibility for the business activities of the various organizational units exercised one level below the Office of the President of the affiliated companies. This is either a Vice President or Sr. Project Manager who has been appointed as an Officer of the affiliated company.

The job titles and descriptions for those positions with day-to-day responsibility for the business activities of Exxon Mobil Corporation's affiliated unit that is involved in the marketing and sales of natural gas and the affiliates that are involved in the production of natural gas in the State of Alaska are listed below. The relative position and reporting relationship for these positions is shown on the aforementioned organizational chart.

1. ExxonMobil Gas and Power Marketing Company ("EMGPM") - Vice President, Americas

   The EMGPM, Vice President, Americas has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the commercialization of natural gas and related products in the Americas region of the world, which includes conducting a marketing function as defined in §358.3(c)(2) of the Commission's regulations. Among other things, the responsibility of the EMGPM, Vice President, Americas includes the submission of bids for capacity and negotiation of

precedent agreements on APP and other potential Alaska gas pipeline transportation projects.

2. ExxonMobil Production Company (“EMPC”) - Vice President, Americas

   The EMPC, Vice President, Americas has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the production and processing of petroleum and natural gas in the Americas region of the world, which includes the State of Alaska. Among other things, the responsibility of the EMPC, Vice President, Americas includes activities related to the submission of bids for capacity and negotiation of precedent agreements on APP and other potential Alaska natural gas transportation projects.

3. ExxonMobil Development Company (“EMDC”) - Vice President, Arctic

   The EMDC, Vice President, Arctic has responsibility for the business, operations and affairs of Exxon Mobil Corporation involving, relating to or in stewarding the development of facilities required for the production and processing of petroleum and natural gas in the Arctic region of the world, which includes the development of the Point Thomson field, support activities related to the Prudhoe Bay Unit and for any other related upstream production activities in the State of Alaska.

Item 21 - Officer and Director Statement

18 C.F.R. §157.34(c)(21): A statement that any officers and directors of the prospective applicant's affiliated sales and marketing units and affiliates involved in the production of natural gas in the State of Alaska named in paragraph (c)(19) of this section will be prohibited from obtaining information about the conduct of the open season or allocation of capacity that is not posted on the "open season" Internet website or that is not otherwise also available to the general public or other participants in the open season.

TC Alaska has no divisions or business operations other than the Alaska Pipeline Project. Neither TC Alaska nor its parent, TransCanada Corporation, has any affiliates involved in the production of natural gas in the State of Alaska. TransCanada is comprised of many affiliated companies and is subject to inter-affiliate codes of conduct, as well as the Commission's Standards of Conduct set forth in Order No. 717. Such codes/standards of conduct are in place to safeguard against improper sharing of information, personnel, or resources and to ensure the independent functioning of APP.

Officers and directors with day-to-day responsibility for TransCanada's affiliated sales and marketing units, as indentified in Items 19 and 20 above, are and will be prohibited from obtaining information about the conduct of the APP Open Season or APP's allocation of capacity that is not posted on APP's internet website (www.thealaskapipelineproject.com) or that is not otherwise also available to other participants in the Open Season.

As a participant in the Alaska Pipeline Project, ExxonMobil has instituted a comprehensive set of Order No. 2005 Compliance Procedures and Standards of Conduct that ensure the independent functioning of APP from all employees conducting a marketing function as defined in §358.3(c)(2) of the Commission's regulations and all production employees engaged in the production of natural gas in the State of Alaska and/or who are involved in activities related to the submission of bids for capacity and negotiation of precedent agreements on APP and other potential Alaska natural gas transportation projects.

Officers and directors with day-to-day responsibility for ExxonMobil's affiliated sales and marketing unit and affiliates involved in the production of natural gas in the State of Alaska, as identified in Items 19 and 20 above, are and will be prohibited from obtaining information about the conduct of the APP Open Season or APP's allocation of capacity that is not posted on APP's internet website (www.thealaskapipelineproject.com) or that is not otherwise also available to other participants in the Open Season.