Date: **June 8, 2011**

To: **Senator Paskvan**

From: **DNR Division of Oil and Gas**

Re: **North Slope Facilities Expansion**

Enclosed is a document summarizing facilities expansion at Prudhoe Bay and Kuparuk, as requested by e-mail from you to Commissioner Sullivan. We have distilled most of your questions down to three basic issues addressed in this response.

1) Current and historical facilities (gas, water, and liquid handling) capacity
2) Effect upon oil production of increasing gas-oil ratios and water cut, and the impact of gas- and water-handling expansions
3) Are increases in gas- and water-handling limits required to increase North Slope oil recovery?

We are limiting this summary to major larger scale processing projects at the Prudhoe Bay Unit (emphasis upon Sadlerochit Initial Participating Area and Western Satellites) and the Kuparuk River Unit. There are also public documents which provide more thorough descriptions of capacities that may be of use to you.[1,2,3] You also requested information on horsepower and investments. It would take a bit more time to track public information down on these items.

While we do not have sufficient public information to quantify the oil production benefits of future gas and water handling capacity investments, it is our belief that additional gas and water handling capacity investments will be necessary in some cases for continuing operation of maturing fields, development and expansion of satellite reservoirs, and to allow for facilities sharing with other new developments outside of current Units. These investments are unlikely to be as massive as that for such items as the Prudhoe Gas Handling expansions and Seawater Injection and Treatment plants; rather smaller, more localized projects, debottlenecking, and upgrades are anticipated within the nearby infrastructure of the major Units.

We hope this is useful to you. If you have questions or need further information, please let us know.

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[1] State of Alaska, Department of Natural Resources, Division of Oil and Gas and and Petrotechnical Resources of Alaska; *North Slope of Alaska Facility Sharing Study;* May 2004;
December, 2009
(http://www.dog.dnr.alaska.gov/oil/products/publications/otherreports/nsfacility/facility.share.report.pdf)

[2] ConocoPhillips Alaska; Facilities Limits; updated 1/6/2010;
http://www.conocophillipsalaska.com/facilityaccess/FacilityLimits.asp

[3] BP Alaska, Inc; *"BP in Alaska"*; 2009;
(http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_bp_in_alaska_2009.pdf)

North Slope Facilities Capacities and Expansions

The summary below addresses capacity limits for processing units within the Prudhoe Bay Unit and Kuparuk River Unit. Specifically we address the following aspects:

1) Current and historical facilities (gas, water, and liquid handling) capacity
2) Historical production volumes, the effect upon oil production of increasing gas-oil ratios and water cut, and the impact of gas and water handling expansions
3) Additional gas and water handling limits needed to increase North Slope Oil recovery

Figures illustrating historical production are provided in a separate PowerPoint file as an appendix.

Prudhoe Bay Unit

The current oil processing capacity of both the IPA facilities and the LPC is mainly limited by the amount of associated gas that can be processed and injected, however there are some limits on water handling. In other words, some of the processing capacities cannot be used because of the inability to process and inject the increasingly higher quantity of gas that is produced with the oil and water. Although efforts to shut off gas have been effective in some wells, in general higher GOR wells must be shut in with each additional new well addition. So, these new wells will "back-out" oil due to shut-in of other Prudhoe wells. The effects of this back-out vary by major processing facilities as outlined below. The following summarizes facilities capacities for the major facilities at Prudhoe Bay.

Current Prudhoe Bay capacities

The following table summarizes publicly available oil, gas, and water handling capacities for the major facilities at Prudhoe Bay. While the sum of gas production capacity at the flow stations may be as high as 10 BCF/D, the rated compression capacity at the Central Gas Facilities limits overall gas production to 8.7 BCF/D. [1]

Table 1

The capacity of each major facility is shown in the following table. However, in actual operations, the capacity of a single facility for a given component cannot be viewed in isolation and instead must be viewed in the context of the overall PBU system and other factors, such as weather and TAPS pro-rations. As such, rarely, if ever, can the capacity of more than one component (oil, water, or gas) be achieved simultaneously.

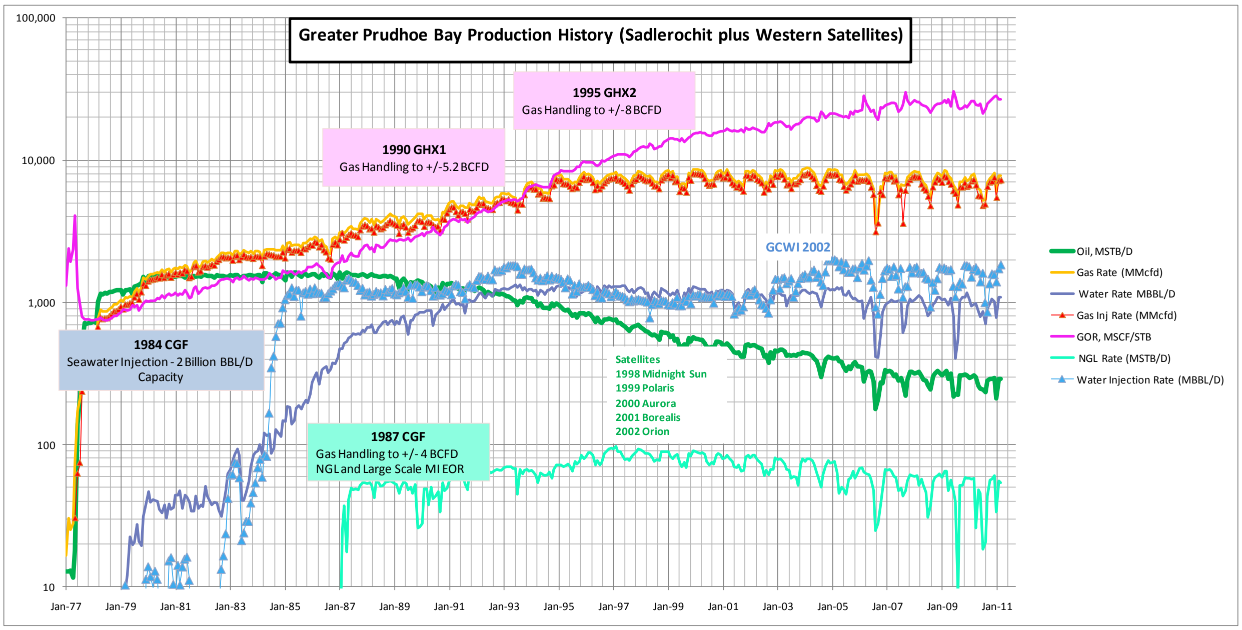
Facility	Oil Capacity MBD	Water Capacity MBD	Gas Capacity MMSCF	Gas Lift Gas Compression Capacity MMSCF
FS-1	360	130	2800	
FS-2	360	650	1150	
FS-3	360	240	1350	460
GC-1	330	150	2600	900
GC-2	250	300 *	1070	
GC-3	**	250	1100	
LPC	205	160	470	
CGF			8700	

* PW Tank currently out of service limits water to ~230 MBWPD
** GC-3 oil processing equipment was taken out of service; must consider GC-3 and FS-3 as single entity for oil processing capacity considerations

[1] ConocoPhillips Alaska Publication; "*Facilities Limits*"; initial publication 2002, updated 1/6/2010; (http://www.conocophillipsalaska.com/facilityaccess/FacilityLimits.asp)

<u>Production and Major Facilities Expansion History</u>

The following summarizes production history and major facilities capacity additions within the Greater Prudhoe Bay area (Sadlerochit plus Western Satellites – excludes Greater Point McIntyre). It should be noted that many smaller facilities and infrastructure expansions have occurred over time to accommodate new wells and drillsites, however major gas handling expansion has not occurred after 1995 with GHX2 addition.

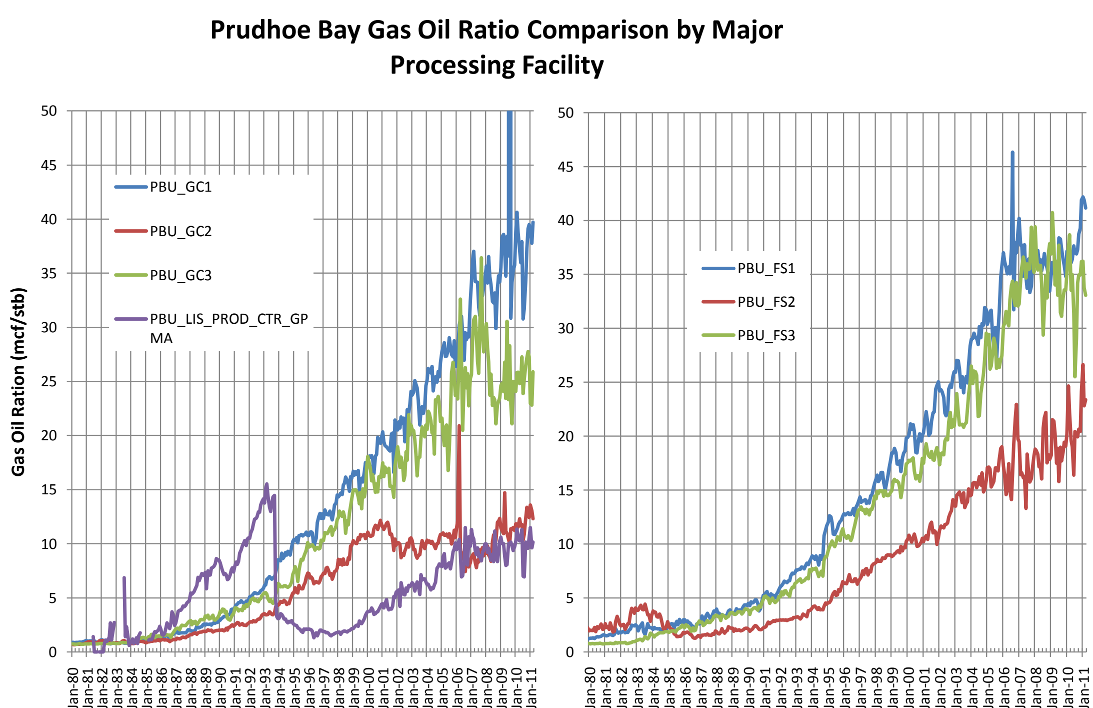


- 1983 - Major Seawater Injection Plant and Seawater Treatment Plant; 2 Billion Barrels per day injection capacity – $2 Billion
- Gas Handling Expansion – Greater Prudhoe Bay
  - CGF 1987 - Gas handling increased from +/- 2.7 BCFD to +/- 4.2 BCFD. NGL processing allows for sales into TAPS and use in miscible gas injection.
  - GHX1 1990 - gas handling increased from +/- 4.2 BCFD to +/- 5.7 BCFD
  - GHX2 1995 – gas handling increased from +/-5.7 BCFD to +/- 8.0 BCFD
- 2002 - Gas Cap Water Injection
  - Seawater is being injected into the Prudhoe Bay Ivishak gas cap to stabilize reservoir pressure.
  - Approximate incremental recovery 150-200 MMSTB (per AOGCC testimony)
- Greater Prudhoe Bay Western Satellites - (Note – Excludes GPMA)
  - Midnight Sun (1997), Polaris (production start date: 1999), Aurora (2000), Borealis (production start date: 2001), Orion (production start date: 2002), Put River (production start date: 2008).

Prudhoe Bay Future Opportunities/Needs

We do not have sufficient publicly available information to quantitatively address the oil production benefits of future gas and water handling capacity investments. However, investments in additional gas and water handling may be necessary to realize efficient and economic oil recovery: 1) for development and expansion of satellite reservoirs, 2) for facilities sharing with other new developments outside of current units, and 3) for acceleration and increased oil rates in the maturing fields. These investments are unlikely to be as massive as that for such items as the Prudhoe Gas Handling expansions and Seawater Injection and Treatment plants; rather smaller more localized projects, debottlenecking, and upgrades are anticipated within the nearby infrastructure of the Prudhoe Bay Unit.

An example of a gas expansion opportunity being considered by the Prudhoe Bay Owners includes a "Gas Partial Processing Plant" which would be placed upstream of Gathering Center 2 at a Z Pad (western portion of the Prudhoe Bay Unit). Currently, the existing GORs are low at GC2 relative to other processing facilities because the facility has not been upgraded with sufficient gas processing capability. As a result, the oil rate benefit from drilling new wells in that part of the field is significantly reduced because even moderate GOR wells have to be shut-in to accommodate the new production. The proposed gas partial processing plant would partially separate gas from incoming production Drill Pads Z, W, L, and V, then dehydrate and compress the gas for use in local gas lift. Such a plant should significantly improve the economics of new western region drilling and is a key component required for a new I Pad viscous oil development. Our very rough calculation suggests that approximately 400 MMSCF/D added gas processing could allow for about 15,000-35,000 STB/D additional oil rate (range depends upon new well and drillsite developments).



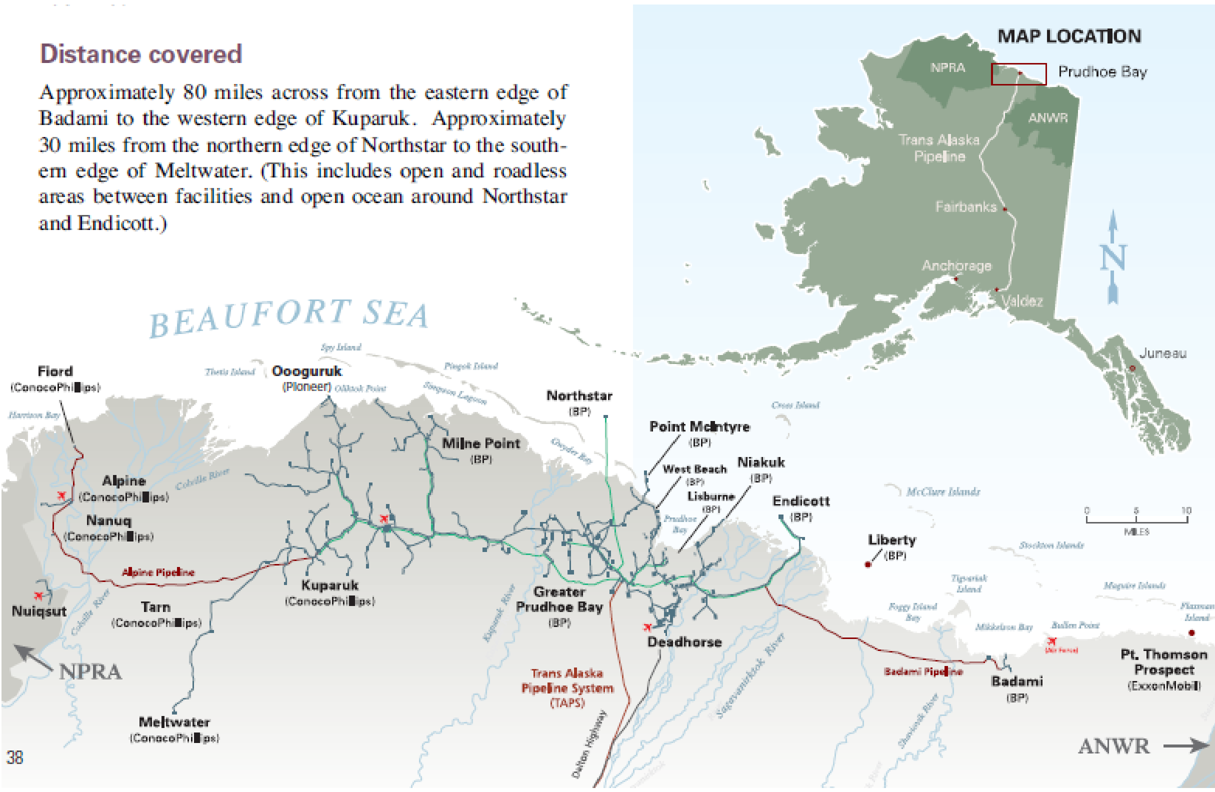
Kuparuk River Unit

Kuparuk River facilities were built and sized for the Kuparuk Participating Area, which is the main PA in the Kuparuk River Unit. Peak liquid throughput was roughly 800,000 barrels of liquid per day. This throughput was achieved both in the late 1990s-early 2000s as well as the 2004-05 period when NGL imports were ended. Peak water production was reached during the 2004-05 liquids peak with 650,000 barrels of water per day. Water injection peaked in the late 1990s, equaling the liquid production rate at the time which was 800,000 barrels per day. Gas production peaked at 400,000 MCF per day in 2002, coinciding with the last gas handling expansion at Kuparuk. These peaks aren't necessarily hard limits, nor can we be 100% certain they can be achieved again in the future. As equipment ages it may lose some capacity so those peaks may no longer be obtainable, but they provide a good guideline for what was possible to achieve with functioning equipment.

As any field matures it is likely to encounter an increased amount of gas and water per barrel of oil. If the current facilities in a field were not designed for the amount of liquid and gas being produced then wells with high GOR and high water cut may need to be shut-in, curtailing production. A facilities expansion would only increase recovery rate if there were shut-in wells to bring online or new wells that could be drilled to produce into the new facilities. In general there will be some tradeoff between how much oil can be gained by increasing facilities and how much those facilities cost. A balance must be achieved in both the initial sizing of facilities as well as any decision to expand facilities later. Kuparuk River facilities were sized in a way where it did not need to expand to deal with increasing GOR and water cut. It is possible to design facilities large enough to not have to be expanded, but that it may not always be optimal.

In some cases new facilities may be necessary to increase North Slope production. There is no question that new oil will need to be processed somewhere, the question is whether that should be somewhere in existing facilities or at a new facility. This comes down to an economic decision of whether it is cheaper to build new or pay to put production through an existing facility. At Kuparuk there is little need to expand facilities for current operations, but if any new satellites were to be brought in, or a new EOR project was undertaken then facilities would likely need to be expanded to accommodate increased volumes. Similarly, the size of a new development will have a lot to do with the decision to rent space or build new. If the development is of a size where it can easily fit into available space, that may be the cheaper option, but if that development is large enough to pay for its own facilities then it is probably optimal to build new and not deal with the expenses and logistical issues of running multiple developments through a single set of facilities.

North Slope Fields Map



See BP Alaska, Inc; *"BP in Alaska"*; 2009; (http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_alaska_bp_in_alaska_2009.pdf)