ALASKA NATURAL GAS
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Prudhoe gas sales in 2020s could be timed well for aging oil field

Sometime in the mid-2020s, the grand strategy for how to produce Alaska's great Prudhoe Bay oil and gas field — send the crude oil and other liquids to market; reinject the natural gas — will be primed to pivot.

That's because gas reinjection, which has proved spectacularly successful in pushing more oil from Prudhoe, will be losing part of its oomph roughly 50 years after that June 1977 day when the first barrel of crude left the field en route to a West Coast refinery.

Gas reinjection applies pressure on the underground oil, moving it toward wells, in much the same way that pumping air into a keg helps the beer flow.

But gas reinjection — called "gas cycling" in the industry — also has been central to a variety of other techniques the Prudhoe Bay operators have deployed to flush more oil from the field. And some of these techniques will be about played out by the mid-2020s. Gas cycling just won't be helping them as much anymore.

The mid-2020s timing dovetails with plans of the Alaska LNG project to start sending maybe a third of Prudhoe's gas production to market around that same period.[1] Those plans are still in the early, formative stage, called pre-front-end engineering and design, with a final investment decision whether to construct the estimated $45 billion to $65 billion project unlikely before 2019.

Prudhoe would be the anchor gas reservoir for Alaska LNG. Other gas would be piped from the Point Thomson field to the east, the North Slope's second largest gas reservoir after Prudhoe.

The start of "major gas sales," as the industry calls them, would mean that Prudhoe, while entering spring as a gas field, officially would be in deep autumn as an oil field.

Prudhoe's oil production would continue for many years, still declining. And natural gas still would be reinjected, just in reduced volumes.

Oil production would slacken somewhat as the reservoir pressure drops with both oil and gas going to market. Some fraction of Prudhoe's remaining oil that could have been produced without gas sales would stay locked underground. But selling that gas would produce tens of billions of dollars in revenue for the producers and the state treasury.

It's hard to overstate how special Prudhoe has been as an oil play. Oil companies have produced more than 12 billion barrels from Prudhoe since its 1977 start-up. It has been the nation's top conventional oil field in daily production since day one. A 37-year run so far. (A few unconventional shale regions produce more oil these days.)

Prudhoe remains No. 1 despite daily production that has plunged from its 1.6 million-barrels-a-day peak in 1987 to today's output of about 250,000 barrels a day, not counting oil from its satellite fields.[2] Prudhoe accounts for about half the total production from all Alaska North Slope oil fields.

By the mid-2020s, Prudhoe will have yielded almost 13 billion barrels of oil and other hydrocarbon liquids, with perhaps another billion to go, especially if decades of gas sales prolong oil production.

Prudhoe's storehouse of natural gas to be sold is colossal in itself. More than 20 trillion cubic feet of gas is available. That's the energy equivalent of roughly 3.5 billion barrels of oil.

By the mid-2020s, with some of the advantages of gas cycling gone, the timing will look better than it has at any time since 1977 to start cashing out Prudhoe's natural gas.

Top U.S. conventional oil fields[1]

Field	Production barrels per day	Location
Prudhoe Bay	262,742	Alaska
Mississippi Canyon (Block 778)	201,918	Gulf of Mexico
Mississippi Canyon (Block 807)	180,822	Gulf of Mexico
Spraberry	108,493	Texas, New Mexico
Green Canyon (Block 743)	104,932	Gulf of Mexico
Kuparuk River	104,110	Alaska
Midway-Sunset	93,425	California
Belridge South	89,315	California
Green Canyon (Block 654)	83,562	Gulf of Mexico
Kern River	78,904	California

[1] 2009 data

Top U.S. tight-oil fields[2]

Field	Production barrels per day	Location
Eagle Ford	1,364,000	Texas
Bakken	1,024,000	North Dakota
Spraberry	466,000	Texas, New Mexico
Bonespring	206,000	Texas, New Mexico
Niobrara-Codell	181,000	Colorado, Wyoming
Granite Wash	161,000	Oklahoma, Texas

[2] Includes shale-oil fields. July 2014 data.

Source: U.S. Energy Information Administration

A TACTICAL STUDY

Gas cycling and the other strategies used to prod oil from Prudhoe are entwined like a quartet's harmony.

Because gas cycling shores up the reservoir pressure, the oil is lighter and more capable of flowing. This means that:

- Extra oil flows as the producers inject water along the edges of Prudhoe to flush oil to wells.
- More production occurs as the producers alternate those waterfloods with injection of a cocktail of gases — called "miscible injectant" — that cause hard-to-flow oil to break its grip on the sandstone holding the riches in place.
- More oil and other hydrocarbon liquids that had been left behind now get picked up — or vaporized — when the injected gas flows over them during cycling. These vaporized liquids then can be produced and sent to market, or made into more miscible injectant.

Gas cycling has been a key tool used to help pressurize Prudhoe, but it isn't the only one. The waterflooding along the oil rim, the miscible injectant and separate water injection above the oil also add pressure. All of these production methods are interlocked.

"Prudhoe Bay has evolved through time to an extensive facility infrastructure fully integrated with the reservoir processes to optimize recovery," two Prudhoe engineers wrote in a 1993 paper, "Prudhoe Bay: Development History and Future Potential," presented at a Society of Petroleum Engineers conference. "Many of the projects implemented in Prudhoe Bay represent the largest of their kind in the world. Integration between projects ... adds another dimension to the complexity of developing incremental opportunities."

The interaction of these strategies, with aggressive well work-overs and ongoing field development, has turned Prudhoe into an overachiever.

SURPRISE DISCOVERY

Prudhoe Bay's story is a tale of the sometimes capricious chemistry of geology, engineering and money.

From the first, a dark day-after-Christmas 1967, when natural gas blew from a wildcat well at a lonesome drill site near a frozen Arctic inlet called Prudhoe Bay, the industry knew it found something special.

When the crew ignited it, the gas jet flared 50 feet despite a 30-mile-an-hour wind, according to one account.[3]

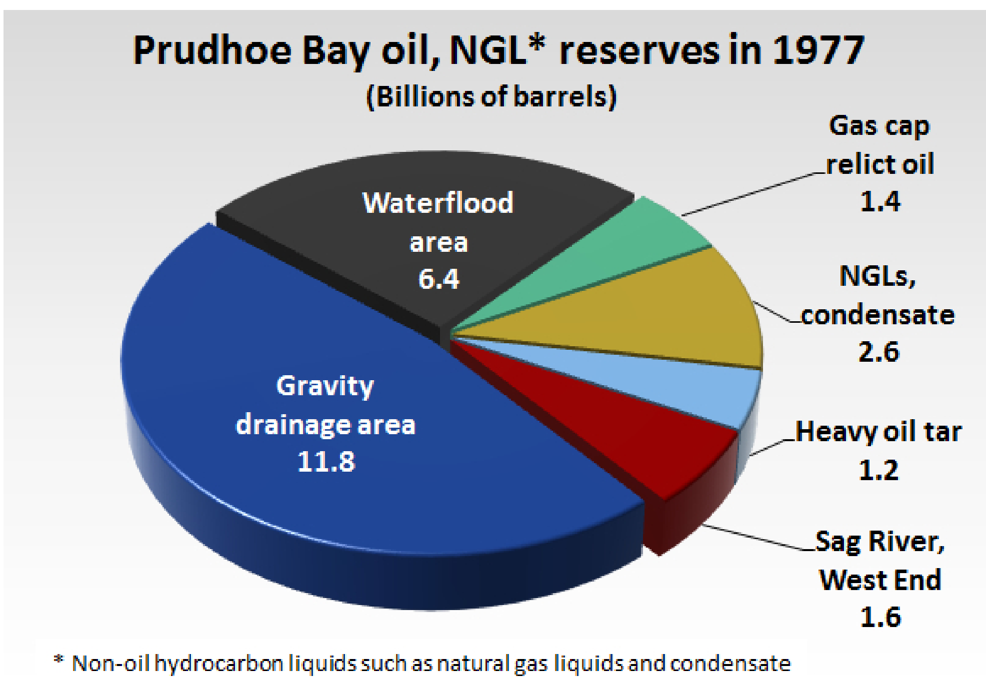
The well had punctured Prudhoe's gas cap. This was a surprise. The well was targeting the Lisburne formation roughly 1,000 feet deeper than Prudhoe, though a secondary target was Prudhoe's Ivishak sandstone. (The Lisburne field officially was discovered in 1969 and started production in 1982.[4])

A confirmation well prompted the Prudhoe discovery announcement in March 1968, and soon came an estimate of what that reservoir a mile-and-a-half underground could yield: a phenomenal 9.6 billion barrels of oil and 26 trillion cubic feet of gas.

Even before production began in June 1977, teams of oil company engineers, geologists, geophysicists and others were analyzing the reservoir with the focus of a grandmaster studying a chessboard. The reservoir held 25 billion barrels, but no oil field surrenders every drop. The 1977 estimate of 9.6 billion barrels produced would be an outstanding result. Coaxing any extra beyond that total would be a sweet bonus.

Today, the Prudhoe Bay producers — mainly ConocoPhillips, ExxonMobil and BP — think they'll ultimately get around 14 billion barrels of oil and other hydrocarbon liquids from the field. They've produced more than 12 billion barrels so far.

Besides gas cycling, pumping water into the field and using miscible injectant, they credit the extra oil to more wells spaced closer together, horizontal drilling and other drilling advances, among other factors. Gas cycling makes them all more robust.



Source: "Prudhoe Bay: Development History and Future Potential," 1993 paper for Society of Petroleum Engineers

The path has involved a series of pivots in how the companies manage Prudhoe. Circumstances changed, so plans changed, too.

In particular, after a few years of oil production, the plan for what to do with Prudhoe's natural gas took a radical turn. And the companies holding oil and gas leases did a radical rethinking of how best to manage Prudhoe.

TOO MUCH GAS

In the first years of oil production, almost everything that rose up the wells was black crude. The little bit of gas mixed in could be reinjected or used to fuel field operations (about 5 percent of the produced gas gets burned as fuel today).

Over time, everyone knew, this would change because more gas would come up the wells. Find a new use for the gas or a way to handle it, or oil production would hit a limit.

The first formal plan for the excess gas emerged during Prudhoe's development as an oil field, as crews drilled the initial wells, laid the 800-mile trans-Alaska oil pipeline and built an oil-tanker port in Valdez during the mid-1970s.

The plan was almost as grandiose as the oil development then underway. A multibillion-dollar project to build a separate gas pipeline system to the Lower 48 states. About 2 billion cubic feet a day of Prudhoe's gas would be sold, starting in the early 1980s, about five years after oil production began.

The timing would solve the problem of more gas coming up with the oil. Gas not piped south or used to run Prudhoe would be reinjected.

To offset the pressure loss from oil and gas both going to market, the companies running Prudhoe would inject water.

In fact, water injection — in massive amounts — began in 1984 after several years of building the plant, pipes, wells and other injection machinery. Injections didn't stop the loss of underground pressure the Prudhoe reservoir was experiencing every year. But water injection slowed it.

Prudhoe Bay timeline

1968	Discovery of major oil and gas field announced.
1977	Oil production begins.
1982	Test of miscible injectant program to enhance oil production.
1984	Waterflooding of oil rim begins, producing more oil, bolstering pressure.
1986	Major expansion of program to handle gas production, separate natural gas liquids, reinject lean gas into reservoir.
1987	Large-scale miscible injectant program begins, working with waterflooding to enhance oil production.
1987	Oil production peaks at 1.6 million barrels a day on average.
1990	Prudhoe's gas handling system is expanded.
1994	Third expansion of gas handling system, allows miscible injectant program to expand, too.
1997	Natural gas liquids production for oil pipeline peaks at 86,522 barrels a day on average.
1999	Major expansion of miscible injectant facilities.
2002	Gas cap water injections begin to stabilize reservoir pressure.

Source: Office of the Federal Coordinator research

Meanwhile, the gas pipeline project died. The market would not support its multibillion-dollar cost.

Something had to be done with Prudhoe's growing gas production. Soon Prudhoe's gas-handling equipment would be overwhelmed.

In addition to the gas pipeline idea, the North Slope companies explored many other concepts for turning Prudhoe's gas into money.

These included gas liquefaction at Prudhoe and LNG shipments on ice-breaking tankers, submarines or airplanes, or turning the gas into electricity transmitted to the Lower 48 states, a senior executive with Sohio (now BP) told a U.S. Senate committee in 1983.[5]

More ideas included chemical conversion of the gas to methanol, building petrochemical facilities at a southern Alaska coastal site or liquefaction in southern Alaska for LNG shipments to U.S. or foreign markets, an Exxon executive told a state legislative committee in 1989.[6]

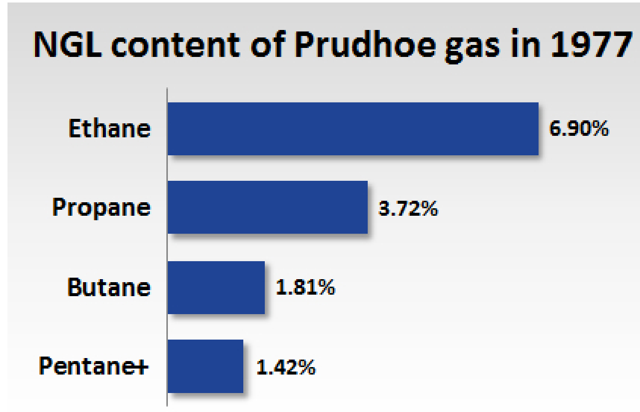
But in the 1970s the gas pipeline to the Lower 48 looked best. In fact it looked so promising that, to raise cash to develop the oil field, Sohio even pre-sold its gas production to a pipeline company that would be on the receiving end of the long Alaska gas pipeline.[7]

By the early 1980s, with no Alaska gas pipeline, the other commercialization ideas still looked unattractive and Prudhoe operators still faced the question: What are we going to do with natural gas getting produced every day if we have no way to send it to market?

They could handle a little over 2 bcf a day with Prudhoe's original machinery. But the volume would be 3 bcf by the mid-1980s, and 6 bcf to 7 bcf by the mid-1990s as more gas and less oil came up the wells. That quantity of gas is massive. It's about half the volume burned in U.S. homes on an average day.[8]

The new plan they devised involved executing some strategies right out of the oil-field management playbook, but deploying them on an enormous scale.

They would muscle up the gas-cycling program, injecting most of the produced gas back into the reservoir. This would give the producers a two-fer: Not only would it pressure more oil to wells as expected, but it would vaporize oil that otherwise wouldn't flow and bring that oil to the surface, too.



Source: Federal Power Commission

In addition, the giant facilities they would build would strip out natural gas liquids from the methane stream. Back then almost 14 percent of the gas was NGLs, such as ethane, propane, butane and pentane.

Once extracted from the stream, these liquids could be put to two purposes.

Some — tens of thousands of barrels a day of butane, pentane, hexane, etc. — could be routed to the oil pipeline and sent to market (they can be used to make gasoline, for example); this would be like producing a whole new oil field.

Some — tens of thousands of barrels a day of propane and ethane — could get brewed with other ingredients into a chemical cocktail called miscible injectant that would help produce more oil; this cocktail would be formulated to loosen the grip of passed-over oil in the reservoir that is stuck stubbornly to rock surfaces.

These plants would be the largest of their kind in the world. They would cost billions of dollars.

The companies executed this plan. As a result, natural gas did, in fact, become a powerful money-maker ... by proxy. It helped Prudhoe cough up billions of additional barrels of oil and other hydrocarbon liquids.

WHY PRESSURE MATTERS

It's wrong to picture oil in a reservoir as a vast underground lake waiting to be siphoned dry.

Rather, oil and gas lie in tiny pores of certain kinds of porous rock, such as sandstone and conglomerate at Prudhoe. And they move to wells via minute connected pathways in the rock, resembling something like a map of the human nervous system.

Simply put, oil pushes through those pathways and rises to the surface because the pressure inside the wellbore is less that the reservoir pressure.

As oil leaves the reservoir, the remaining reservoir contents become less compact; what's left sort of relaxes. If the pressure falls too much, oil production stops.

The reservoir will offset some of this pressure decline automatically, the text "Fundamentals of Petroleum" notes.

For example, the rock itself will expand — ever so slightly.

Water and oil still in the reservoir will expand a bit more than the rock.

Some gas dissolved in the oil — called "solution gas" — will bubble out of the oil as the pressure falls, just as carbon dioxide bubbles free when a soda bottle is first opened and the pressure is reduced.

Finally, expanding the most is a layer of mostly natural gas that lies above the oil — a layer called the gas cap.

Of Prudhoe Bay's original 26 trillion cubic feet of gas, 18 trillion was in the gas cap. The other 8 trillion was in solution. The gas cap also held some oil, as we will see.

But these natural changes in pressure have their limits and do not offset all of the pressure loss that occurs as oil leaves the reservoir.

Prudhoe Bay's original reservoir pressure was 4,335 psi (pounds per square inch). Today it's about 3,300 to 3,400.

Less pressure means less oil production. This is true for several reasons:

- As pressure drops, more of the hydrocarbons dissolved in the oil will fizz out and become vaporous rather than the liquids they were under higher pressure. The industry term is "oil shrinkage." That's just the nature of their chemistry — a change in temperature or pressure can transform a hydrocarbon from a liquid to vapor, or vice versa.
- As pressure drops the oil becomes thicker, or more viscous, without those lighter hydrocarbons that have fizzed out. The more viscous the crude, the less of it that flows to wells.
- Without the lighter hydrocarbons, less NGLs are produced for the oil pipeline. Also, less are produced to make miscible injectant, so less of that cocktail is available to produce stubborn, clinging oil from the reservoir.

Pressure is to Prudhoe what gravity is to rainfall. It is a dynamic behind most strategies that produce Prudhoe's oil.

FALLING PRESSURE

Prudhoe Bay's reservoir pressure has stabilized at around 3,300 to 3,400 psi since about 2002. It has even risen a little bit.

This has occurred even as billions of barrels of liquids have been extracted and sent to market.

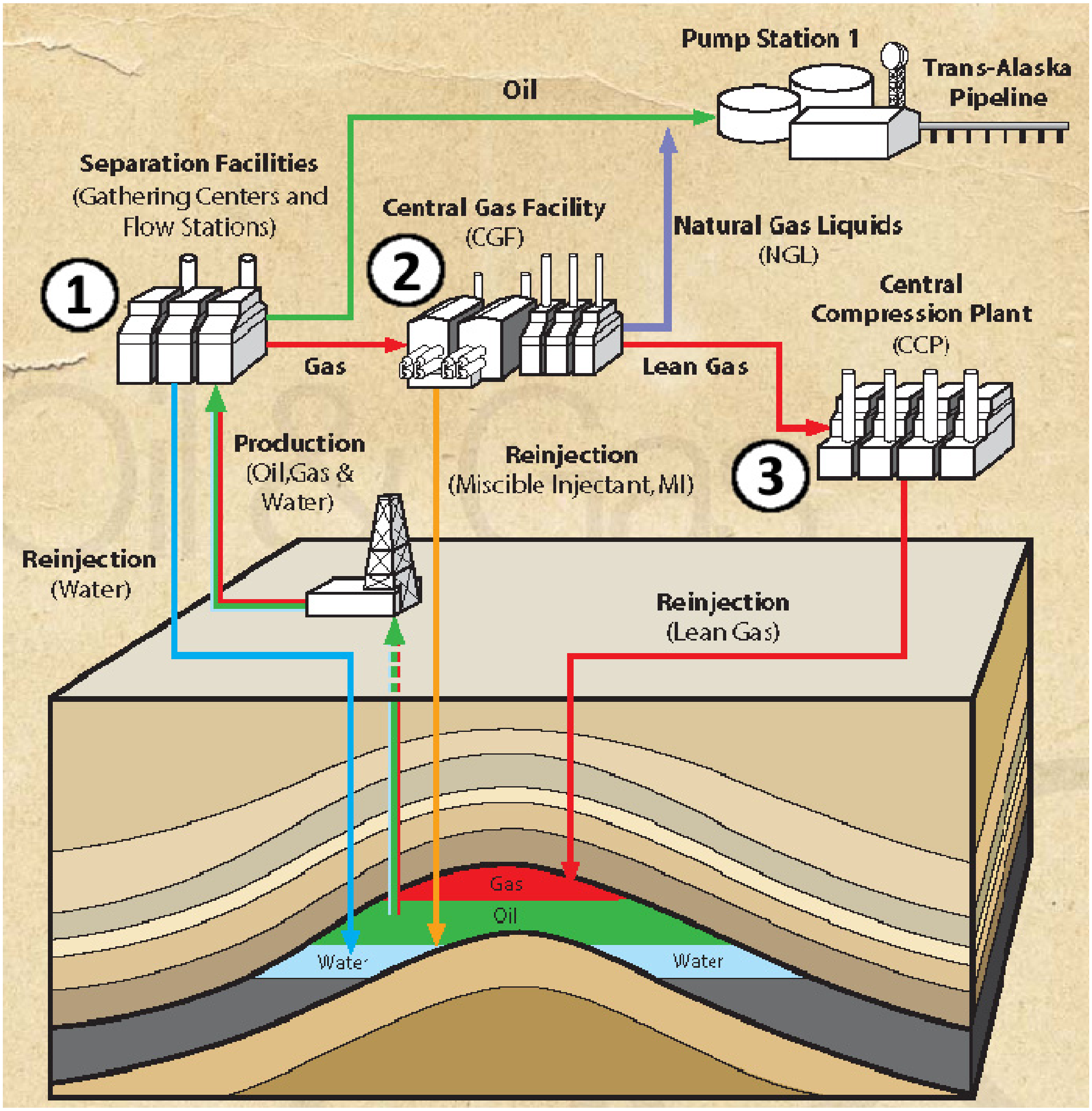
The reason is due to ingenuity and engineering muscle, as well as billions of dollars, the Prudhoe producers have invested over the decades to manipulate what happens in Prudhoe's nearly 600-foot-thick oil-and-gas zone.

As was said, Prudhoe Bay's original reservoir pressure was 4,335 psi, about 30 percent higher than today's pressure.

When oil production began in 1977, the pressure started falling about 70 psi a year.

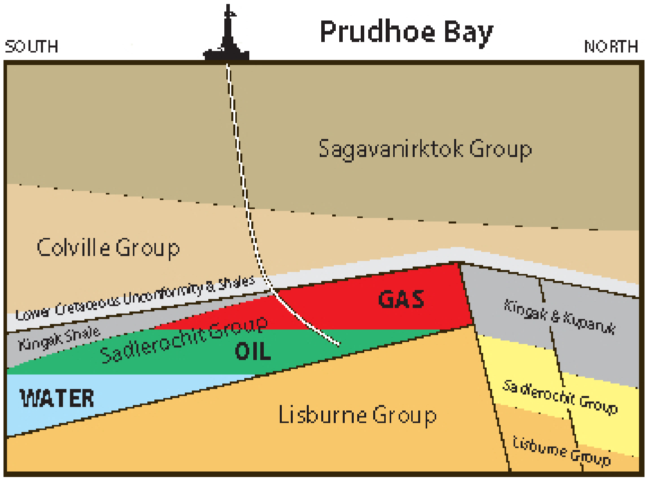
After massive water and gas injection began in the mid-1980s, the pressure decline slowed, falling about 25 to 35 psi a year.

How the Prudhoe Bay field works



Source: Alaska Oil and Gas Conservation Commission

The Prudhoe Bay leaseholders deploy a variety of strategies to maximize production. 1) Oil, gas and water that rise up the wells get separated. Water is reinjected to sweep more oil to wells, produced oil is sent to the trans-Alaska pipeline and gas goes to a plant for further treatment. 2) The Central Gas Facility separates the gas into three streams. Some natural gas liquids are routed to the oil pipeline, some gas is made into miscible injectant to work with reinjected water to produce more oil, and most of the gas, which is now very dry, or lean, is sent to the nearby Central Compression Plant. 3) The lean gas is injected under high pressure into the gas cap to help pressurize the reservoir and vaporize oil that has been left behind.



Source: Alaska Oil and Gas Conservation Commission

The Prudhoe reservoir — in 3-D — looks sort of like a messy sandwich made by a 2-year-old, with the top and bottom bread slices only partly covering the filling. Prudhoe's gas cap overlies only the northeast part of the oil column. The water underlies much of the rest of the oil column.

Between them, the injected water and gas act like a pincer, squeezing the oil column from above (gas) and below (water). The miscible injectant works with the water: The water flushes oil (and helps pressure the field), then miscible injectant loosens the remaining oil, and finally more water flushes the now loosened oil.

The miscible and gas injections were enlarged after a series of major plant expansions in the 1990s. But although they dealt with growing gas production and produced more oil, Prudhoe's pressure continued to drop 25 to 35 psi a year, as expected.

Officials with the Alaska Oil and Gas Conservation Commission were concerned about the falling pressure.[9] They are charged with regulating Prudhoe and other fields to ensure as much oil and gas as possible are produced.

In 1992, the commissioners instructed the Prudhoe producers to investigate options to slow the pressure drop further and report annually.

The producers already had formed teams to take on the problem.

OLD IDEA, NEW LIFE

The companies studied a variety of options to "mitigate pressure decline," according to 2001 testimony to the AOGCC from Perry Richmond, a BP waterflood manager:

- Obtaining natural gas from another field, such as from Point Thomson, for injection at Prudhoe.
- Injecting a natural gas substitute, such as nitrogen.
- Burning something other than natural gas to fuel the oil field so that more gas would be available for reinjection.
- Ramping up water injection.

Imposing any new program is a tricky business when melding it with a whole program of expensive strategies that already work at Prudhoe.

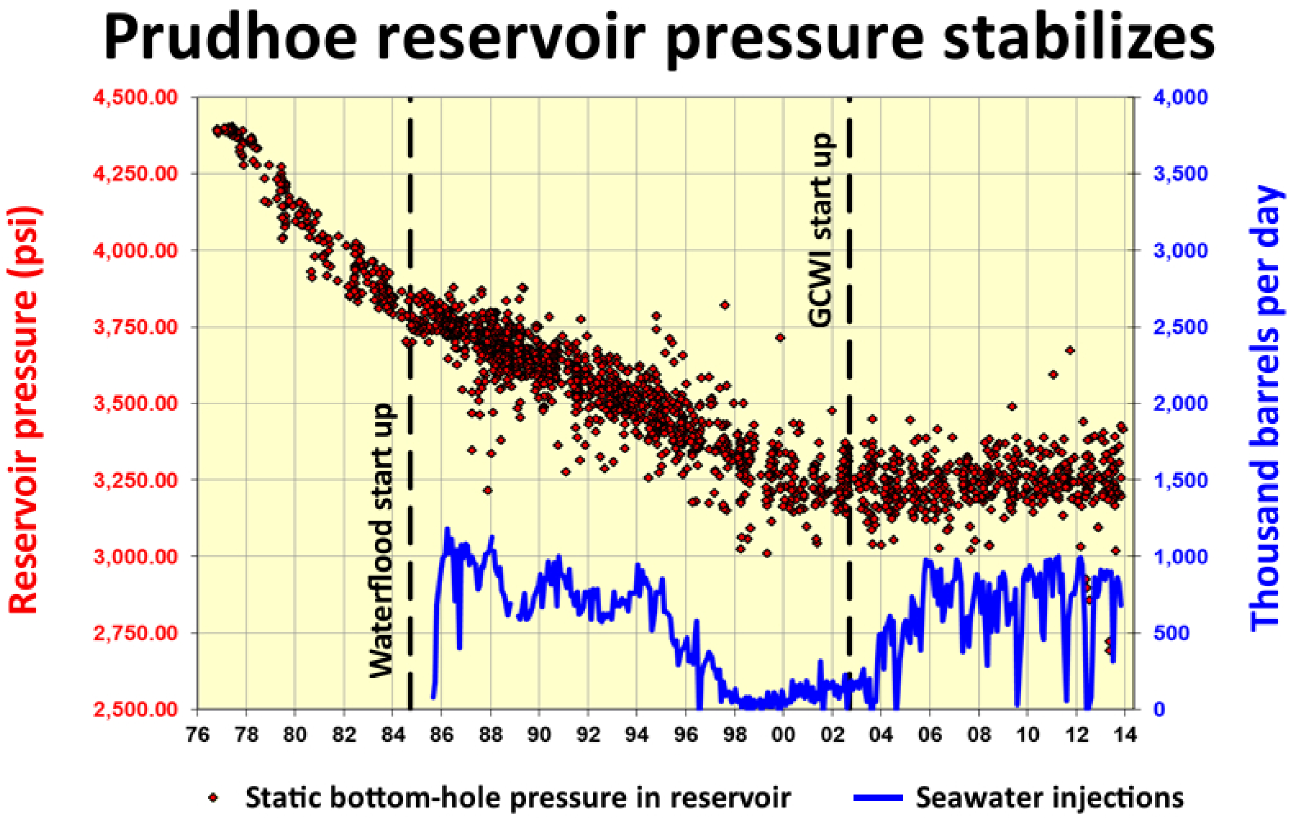
As two ARCO engineers wrote in a paper, "Reservoir Management of the Prudhoe Bay Field," presented at a 1997 Society of Petroleum Engineers technical conference (ARCO Alaska helped develop Prudhoe and is a predecessor company of ConocoPhillips):

"Progressive development of a fine-tuned, highly integrated facility reservoir system steadily increased the complexity of evaluating new projects that would potentially disturb an existing balance."

By 2001, the Prudhoe producers had their solution to the reservoir's falling pressure.

They would inject massive amounts of water — not into the reservoir periphery where water injections already occurred, but into the top ... into the gas cap.

The idea — called simply "gas cap water injection" — wasn't new within the industry. In the early 1970s, when the companies were mulling how to develop Prudhoe, it was even plugged into a reservoir simulator model for the field, an ExxonMobil engineer, Lynn Schnell, told the AOGCC in 2001.



Source: BP

Pressure drives oil to the wells. Oil production causes reservoir pressure to fall. The Prudhoe Bay reservoir pressure has declined from about 4,335 pounds per square inch when oil production began in 1977 to just under 3,400 psi today. The start of waterflooding along the reservoir's oil rim in 1984 helped slow the pressure loss. The start of seawater injections into the gas cap in 2002 stabilized the pressure loss.

The injection began in 2002. The producers pump about 520,000 barrels a day of seawater into the eastern part of the gas cap. They inject that water as far away as possible — more than two miles — from the nearest oil wells and natural gas injection wells. The injected water front is slowly pushing westward toward these wells.

Sometime in the mid-2020s, the injection will end. The water front basically will stop migrating, according to a 2001 AOGCC conservation order about the program.[10]

The front will have reached the northern oil-producing wells in what is known as Prudhoe's "gravity drainage area" — think of that area as the mother lode. The gas-cap's methane will be compressed into a tighter, mostly water-free space over the gravity drainage area. The field will be primed to start drawing off some of the gas.

The 2002 gas cap water injection program did more than "mitigate pressure decline." It stopped the decline.

Prudhoe's pressure has stabilized at not quite 3,400 psi. In fact, Prudhoe is now gaining 1 to 2 psi of pressure a year.

The program's other goal is to produce more oil.

The seawater injection is on target to produce an extra 170 million to 200 million barrels of hydrocarbon liquids from Prudhoe, the industry says.

"The increased pressure resulting from GCWI [gas cap water injection] improves every (oil) recovery mechanism operating in the field," Bharat Jhaveri, a reservoir engineer with BP, told the AOGCC in 2001.

TARGET: RELICT OIL

Gas cap water injection won't be the only program about played out in the mid-2020s.

The gas-cycling "vaporization" of hydrocarbon liquids won't have much life left either. Most of the vaporization possible will have occurred in the preceding 50 years.

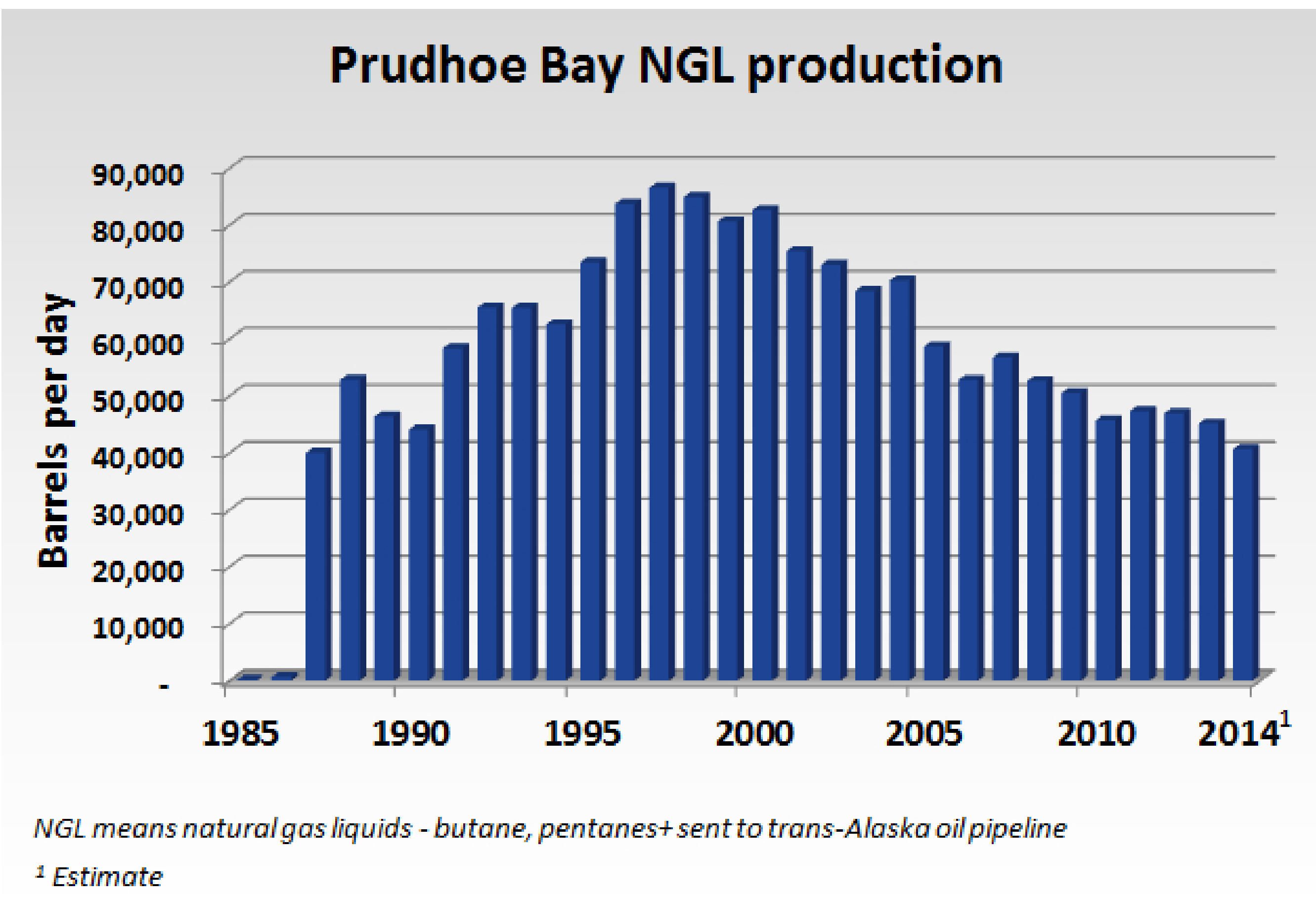
Vaporization has targeted two kinds of hydrocarbons in particular.

One is called "relict oil." This is the oil in the gas cap that never drained down into the oil column when oil and gas were separating over millions of years. BP, which runs the Prudhoe field, likens relict oil to "the final amount of ketchup in an upturned bottle" that no longer flows.[11]

Prudhoe's gas cap originally had a lot of relict oil, about 1 billion barrels.

The other key vaporization target has been about 3 billion barrels of residual oil, condensate and other hydrocarbon liquids left behind as oil is produced, the oil column shrinks and the gas cap expands. Some of these are hydrocarbons that fizzed out of oil as the reservoir pressure fell.

Unlike the gas coming up the wells with oil, the reinjected gas going back into the reservoir has been stripped of its hydrocarbon liquids. That is done by chilling the produced gas in a giant plant. Remember, temperature changes will cause some vapors to become liquid, and these natural gas liquids that drop out of the produced methane are



Source: Alaska Oil and Gas Conservation Commission sent to market via the trans-Alaska oil pipeline or made into miscible injectant. What's left, the bulk of the gas stream, is what the industry calls "dry" or "lean" gas, mostly methane — the same gas that burns in home furnaces.

This injected lean gas now has capacity to absorb more hydrocarbon liquids as it passes over them in the reservoir. Rinse and repeat.

The same principle is at work when a damp towel hung on a Phoenix clothesline at 100 degrees dries faster than at the same temperature in humid Houston — the dry desert air has more capacity to absorb the towel's moisture.

Prudhoe's gas cap has been expanding — and the oil column shrinking — since 1977. By the mid-2020s, the gas cycling will have touched most of the relict and residual oil. In fact, most already has been produced. This can be seen in Prudhoe's NGL production. Although the flow of natural gas up wells has been relatively steady since NGL production peaked in 1997, the volume of NGLs extracted from that gas stream and sent to the oil pipeline has fallen about 50 percent since then because there are less and less NGLs to capture.

THE COST OF GAS SALES

If the Alaska LNG project starts up in the mid-2020s, some of Prudhoe's daily gas production would be sent to market, perhaps one-third. The project sponsors have yet to specify how much gas would come from Prudhoe and how much from the Point Thomson field.

Gas not piped south to the LNG plant would be handled as it is today: some would power the fields, some gas liquids would go to market or be made into miscible injectant, most of the produced gas would be reinjected for gas cycling.

Pressure in the Prudhoe reservoir would start falling.

That would mean some hydrocarbon liquids would get left behind because of oil shrinkage, more viscosity, less miscible production and less vaporization.

How much less is unclear from the public record.

What is clear is that had major gas sales begun earlier, Prudhoe would have produced much less oil.

Cathy Foerster, a petroleum engineer and current state oil and gas commissioner, has said that if the gas pipeline proposed for the early 1980s had started, it's possible that Alaska's North Slope would be finished today as an oil realm, instead of having perhaps decades of production left.

In 1991, Lod Cook, then chief executive of ARCO, told the U.S. secretary of energy in a letter that, "If major gas sales of two billion cubic feet per day were to begin late in this decade, the loss of recoverable crude oil would be about one billion barrels. If such sales were delayed until 2005, the loss still would be about one-half billion barrels. In short, early sale of gas from the North Slope will substantially reduce the amount of available domestic oil from the Prudhoe Bay Field."

In 2009, a National Energy Technology Laboratory report considered oil loss due to a contemplated 3.44 bcf-a-day gas pipeline starting in 2018.[12] The study predicted 234 million barrels lost from Prudhoe over time, offset by 400 million barrels of new oil and condensate production from the Point Thomson field, which would be developed to tap its gas for a gas pipeline.

The trade-off of some lost oil production due to significant gas sales will be studied in coming years by the Prudhoe producers and Alaska Oil and Gas Conservation Commission regulators.

Ultimately, the commissioners, charged with maximizing the recovery of Alaska's resources, will decide whether the approach to managing Prudhoe is ready to pivot, whether it's time for major gas sales.

Certain to be part of their calculation will be the fading effectiveness of some long-used strategies for producing the famous field's oil.

Notes

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