Liquefaction plant single largest cost for Alaska LNG project

The biggest building on Earth is Boeing's wide-body assembly plant in Everett, Wash. It covers an area as large as 18 Manhattan city blocks, stands 11 stories tall, and encloses almost 500 million cubic feet of space.

Imagine you have six of those buildings, all filled with natural gas from Alaska's North Slope. Your assignment: Figure out how to shrink the gas enough so that all of the methane in those six buildings can be loaded onto a single, 900-foot-long tanker and shipped to market.

The solution: Supercool the gas to 260 degrees below zero, so that it turns into a liquid.

Now the molecules will be packed so tight that the gas — which once reached all the way to the 114-foot ceiling — will be a puddle just over two inches deep on the floor. At that shrunken volume, liquefied natural gas can be loaded aboard insulated tankers — sort of like floating Thermos bottles — for shipment around the world.

That process is at the heart of the latest proposal for getting the North Slope's vast natural gas reserves into the hands of buyers.

A smaller-size tank in Greece was estimated at $150 million last year, and a larger version in Singapore was estimated at $500 million.

But transformation comes at a high price. A liquefied natural gas plant able to operate on the scale sketched above, which is now being considered for Alaska by ExxonMobil, BP and ConocoPhillips, could cost $20 billion or more to construct, based on the price tag of similar projects around the world in recent years.

And that's only one item on the invoice. Throw in a short pipeline to bring gas from a newly developed North Slope field to Prudhoe Bay, plus what would be one of the world's largest gas treatment plants at Prudhoe to purify the methane stream, plus an 800-mile pipeline to get the gas from the North Slope to the LNG plant at tidewater in Southcentral Alaska, plus up to eight compressor stations along the way to keep the gas moving.

Then add in massive storage tanks at tidewater to hold the LNG while waiting for four or five tankers to arrive each week, the docking jetty, berths and loading equipment, and you begin to see the reality behind the producers' estimate of $45 billion to $65 billion for the total cost of the project they call Alaska South Central LNG.

LIQUEFACTION PLANT COSTS

The producers haven't broken out details of their cost estimates, such as specifics for the tidewater LNG plant. But it's possible to sift the $20 billion ballpark estimate from public data assembled by international energy consulting firm Wood Mackenzie, and by oil and gas producer Apache Corp., which itself wants to build an LNG export operation with partner Chevron at Kitimat, B.C.

Wood Mackenzie examined the subject in a 2011 report for the Alaska Gasline Port Authority, vocal proponents of an LNG terminal at Valdez. Wood Mackenzie estimated building an Alaska LNG plant would cost $1.2 billion per million metric tons of capacity. (Liquefied natural gas generally is measured in tons, as opposed to its vaporous cousin, which is measured in the cubic feet of space it fills up. A ton of plant capacity is the ability to produce one ton of liquefied gas per year.)

Apache, meantime, early this year assembled capital costs for 10 foreign LNG plants that started construction in the past three years; the average came to around $1.26 billion per million tons of annual capacity.

The Alaska project, as proposed by the three producers and TransCanada, their pipeline-building partner, would have an output capacity of 15 million to 18 million tons a year. Assume an Alaska project costs the same to build as those in Papua New Guinea, Australia, Angola, Indonesia and other places considered in the two studies cited above, and you get a cost range of $18 billion to $23 billion.

Of course, if you allow for higher construction costs in Alaska and inflation — the Wood Mackenzie estimate was in 2011 dollars and Apache's summary includes projects started since 2010 — the Alaska LNG plant could cost more than $20 billion.

However, James Jensen, a Massachusetts-based consultant in natural gas economics, notes that the Apache figures rely to a considerable extent on a special case: Australia, home to seven of the 10 plants in the Apache roundup. "The Australians," Jensen said, "have basically lost control of their costs. They're going crazy."

One example: An Australian project called Gorgon LNG. It was originally projected to cost $37 billion; the latest estimate is $52 billion, though the foreign exchange rate for Australian dollars is part of the cause.

The Australian example, Jensen believes, may be prompting project sponsors elsewhere to allow plenty of wiggle room in their own estimates.

"I'm sure everybody in Alaska is putting in a lot of contingency to avoid getting clobbered like with the Australian projects," he said.

What accounts for the soaring costs of Gorgon and the other Australian projects? Essentially, it's critical

Major components of a large-volume Alaska LNG project

Point Thomson gas pipeline

- 58-mile, 30-inch-diameter pipeline to move natural gas from the Point Thomson field to Prudhoe Bay.
- Estimated at as much as $800 million by North Slope producers in 2010.

North Slope gas treatment plant

- Among the largest in the world, the plant would remove carbon dioxide and other impurities from the gas stream.
- A larger version of the plant was estimated at $9 billion to $13 billion by North Slope producers in 2010.

North Slope pipeline to tidewater

- 800 miles of 42-inch-diameter pipeline from Prudhoe Bay to a liquefaction plant site on Prince William Sound or Cook Inlet.
- A slightly larger pipeline was estimated at $11 billion to $14 billion by TransCanada/ ExxonMobil in 2010.

Natural gas liquefaction plant

- One of the world's largest liquefaction plants to produce LNG.
- Capacity to produce as much as 900 billion cubic feet of gas a year as LNG (averaging 2.4 bcf a day).
- Possibly $18 billion to $23 billion, based on construction costs of LNG plants worldwide the past three years.

LNG storage tanks

- Two storage tanks, each capable of holding enough LNG to fill a standard-size tanker.
- A smaller-size tank in Greece was estimated at $150 million last year, and a larger version in Singapore was estimated at $500 million.

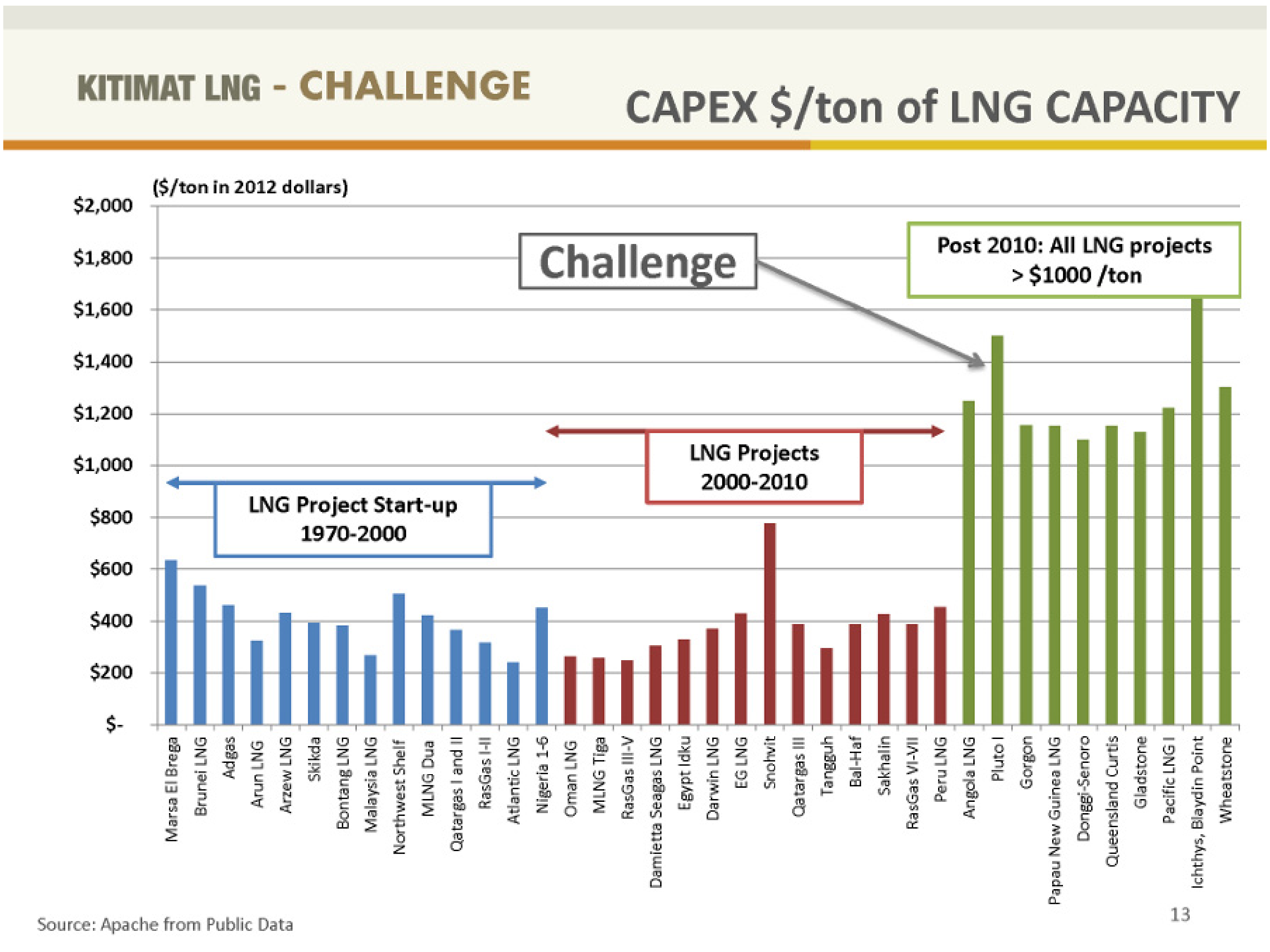
shortages of labor and expertise. Experts watching the Australian situation, Jensen said, attribute it to "too many projects moving too fast based on too small a workforce and too few contractors in too small a country."

He cites the contractor crunch in particular. "There is a limited number of companies who can do these projects on time and on budget, and these guys don't even answer their telephones anymore."

Still, even Jensen doesn't think an Alaska project could come cheap. His own computer model for a "standard" LNG plant puts the cost of the producers' South Central LNG plant with a capacity of 18 million metric tons — including an allowance for the higher cost of doing business here — at a little over $14 billion.

Meanwhile, Resources Energy Inc., a group of Japanese companies looking to get into the game on the Alaska liquefaction plant project, in May unveiled its own estimate of $23.7 billion for an LNG plant at Valdez capable of 20 million tons a year, or almost $1,200 per ton.

Whatever the best guess, why so much? What makes the massive supercooling plants so expensive?



Source: Apache Corp.

Apache Corp. earlier this year assembled a chart of capital costs for LNG export plants going back to the 1970s, showing the dramatic increase in construction costs in recent years. The Apache official who presented the chart at an industry conference said the challenge is to control costs in LNG project development. (Costs are listed as per ton of annual LNG output capacity.)

ECONOMIES OF SCALE

When it comes to LNG plants, the decision usually boils down to two choices: big, or even bigger.

That's because the bigger the plant, the lower the cost of each ton of LNG it can produce.

"It's not as if you can build a 4 million-tons-per-year plant and it'll be half the cost of an 8 million-tons-per -year plant," said Nelly Mikhaiel, a gas and LNG consultant with FACTS Global Energy. "It doesn't work that way. You try to make it as big as possible to achieve economies of scale."

Mikhaiel ticked off a list of what has to go into an LNG export project, depending on location: liquefaction trains; storage tanks; docks and jetties for loading the LNG onto tankers; utilities such as power, water and sewer; control rooms; shops; warehouses; perhaps even permanent housing for staff.

"It's hard to wrap your head around just how big they are," Mikhaiel said.

Indeed, she noted, building what's needed just to get started on an LNG plant can be a substantial construction project in itself: roads, airstrips, construction docks for material and equipment delivery, utilities, and housing for construction workers.

The need to build a small town before construction can even commence," she said, "is an indicator of the size, complexity and, therefore, cost of the undertaking."

The three-train South Central liquefaction facility will be big a pretty big and complicated one if it's ever built. The project sponsors estimate it could cover up to 600 acres, equal to over 100 Manhattan city blocks. It would be almost a city unto itself, complete with its own utilities and, at its peak, a workforce that could reach 5,000 people.

(An LNG train, or module, is one complete stand-alone processing unit, capable of carrying out all of the steps in the complex process of turning natural gas, from its vapor form, into liquid methane. Thus, an LNG plant with two trains can produce twice as much as a single-train plant, and so on.)

Other, more transient cost factors are also at play today, Mikhaiel said. Like Jensen, she pointed to the demand for contractors and workers with expertise in LNG plants. In addition, she noted that these same workers and contractors are in demand by other booming industries that need similar expertise, such as oil, petrochemicals and mining. Consequently, contractors and laborers alike can charge premium rates.

Moreover, she said, prices for the raw materials needed for an LNG plant — steel, for example — have been on the upswing recently, further increasing costs.

In Alaska's case, location is an additional cost factor. Doing anything costs more where the weather is harsh; workers have to be paid more to entice them to work in such weather in remote locations.

Source: Chevron

The first phase of the workforce accommodations are complete at Chevron's Wheatstone LNG project in Western Australia. When completed, the construction community will house 5,000 workers.

"It really is a perfect storm in many respects when looking at the capital expenditure costs for LNG projects," Mikhaiel said.

Source: SCLNG

A coastal Alaska LNG-export plant could look something like this illustration, provided by the South Central LNG project sponsors.

OTHER PIECES OF THE PIE

While the LNG facility at tidewater may wind up as the most expensive component of the Alaska project, there are also other costly construction tasks, each possibly approaching a billion dollars — or multiples thereof.

There is the short pipeline from the Point Thomson field (with 8 trillion feet of gas, almost one-quarter of the North Slope's proved reserves), the gas treatment plant at Prudhoe, the pipeline to Southcentral Alaska and its compressor stations, and LNG storage tanks at the end of the pipe.

The Office of the Federal Coordinator prepared the following ranges — using cost estimates from previous efforts by TransCanada and by the producers to develop North Slope gas — merely as examples to show what such components can cost.

Differences between projects, such as the size of the pipe, steel specifications, capacity of the gas treatment plant, construction plans and other variables all mean these numbers are, at best, within a ballpark range — think large outfield, not the tighter confines of the infield — for the South Central Alaska LNG project. For example, the output of the South Central LNG plant would be less than either of the two proposed producer-led projects in recent years, no doubt affecting the numbers.

Put the numbers for all the components into the Osterizer, add some more numbers for the LNG loading facilities, tanker berths, utilities, support buildings and other pieces of the project, hit the mix button and you get a rough estimate of the cost range for a South Central-scale project in $40s billion to $50s billion range — pretty close to the numbers released by the South Central project sponsors.

Point Thomson pipeline

The 58-mile line would carry natural gas to Prudhoe from Point Thomson, a long-known North Slope natural gas and condensate field under construction and scheduled to start liquids production in the winter of 2015–2016 — with gas production to follow just as soon as there is a pipeline to market. ExxonMobil is the field operator. The gas line would be included in the South Central LNG development; it is not part of Exxon's Point Thomson project, which includes its own, separate oil line.

The short gas line was estimated in recent years to cost as much as $800 million.

That comes from two earlier proposed North Slope natural gas projects that submitted filings with the Federal Energy Regulatory Commission in recent years — the BP/ConocoPhillips project known as Denali, which closed down in 2011, and the ExxonMobil/TransCanada proposal known as the Alaska Pipeline Project.

Under the earlier ExxonMobil-TransCanada proposal, presented in 2010, the Point Thomson line would be sized to move 1.1 billion cubic feet of gas a day westward to the operations at Prudhoe Bay. That project proposed feeding as much as 5.3 billion cubic feet of gas a day from Prudhoe Bay and Point Thomson into the gas treatment plant, sending 4.5 bcf a day of cleaned gas down the line to Alberta to connect with North American markets.

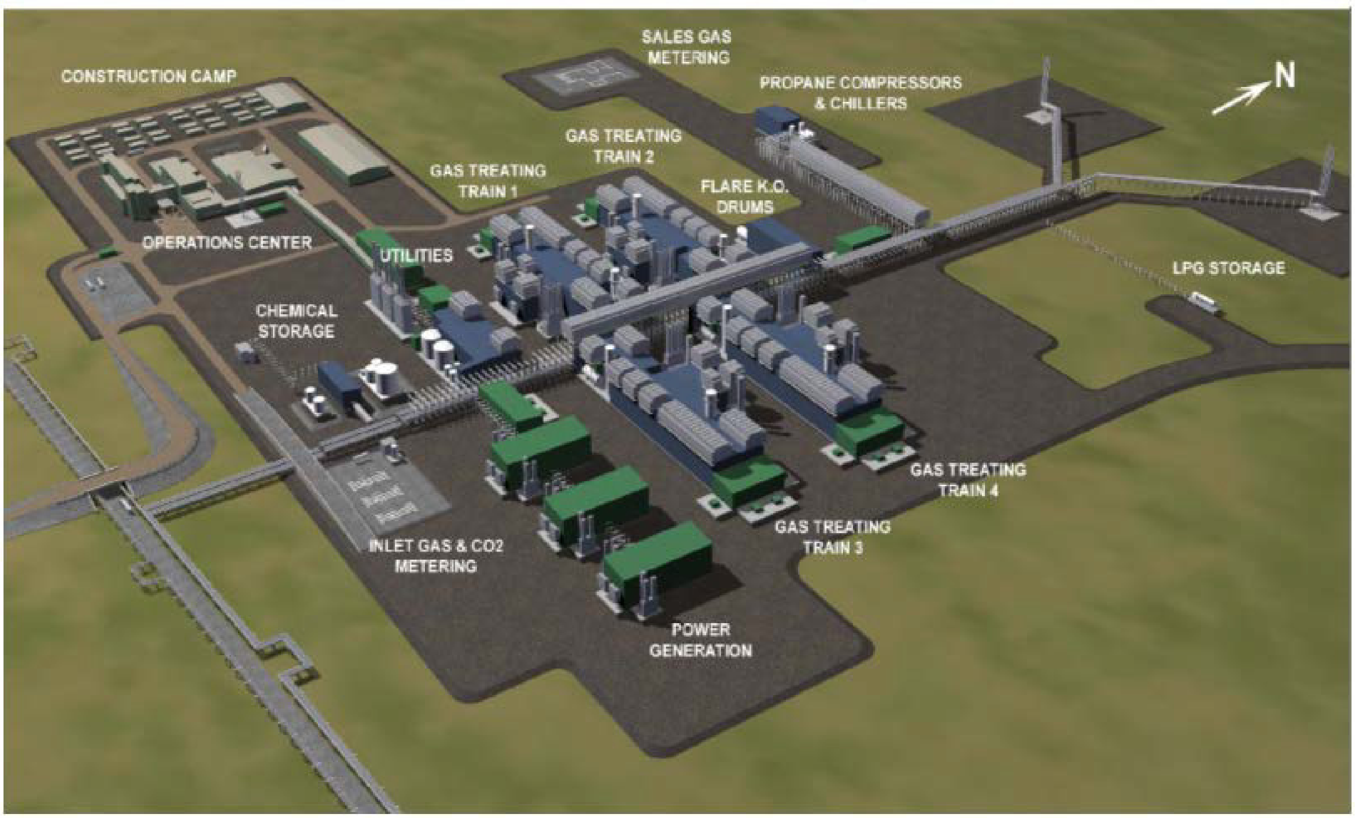
The current venture of TransCanada and the producers told the Alaska Legislature in February it anticipated the mainline moving 3 bcf to 3.5 bcf per day from the North Slope. After subtracting the gas consumed along the way at pipeline compressor stations, gas withdrawn along the way for Alaska's needs, and gas burned up at the liquefaction plant to power the process, the companies figure they would have 2 bcf to 2.4 bcf a day of natural gas ready to ship out as LNG.

The venture also told lawmakers in February that 2 bcf to 2.5 bcf of gas a day would come from Prudhoe Bay, and 1 bcf a day from Point Thomson, depending on seasonal fluctuations. Under the current producer -TransCanada venture, the Point Thomson line would be 30 inches in diameter.

Gas treatment plant

Just a few years ago, this was estimated at $9 billion to $13 billion, though for a larger project at the high end of that range. This massive North Slope facility would purify, chill and compress gas from Point Thomson, Prudhoe and possibly other fields to prepare it for shipment to market. It's worth noting that any project to move gas off the Slope would require a facility to remove impurities, especially carbon dioxide.

Treatment is required because North Slope gas in its natural state, like most gas deposits, is unsuited for market or transmission by pipeline. Cleaning out corrosives such as hydrogen sulfide from the gas stream before sending the gas to the mainline is essential.



Source: SCLNG

The South Central LNG project team provided this illustration of a possible layout for the North Slope gas treatment plant.

The Prudhoe Bay gas stream coming into the plant would run about 12 percent CO2, which would be removed and pumped back down into the reservoir to help pressurize North Slope fields and aid in oil recovery. The Point Thomson gas flow is about 4 percent CO2.

The four-train plant would be among the largest in the world, according to the South Central LNG team. Its footprint could measure as much as 250 acres (about 50 Manhattan city blocks) and it would require up to 300,000 tons of steel for construction. That's as much steel as four, maybe five of the largest nuclear-powered aircraft carriers in the U.S. fleet.

While that's about as much as been revealed on the gas treatment plant for the current proposal, Denali's preliminary design for its four-train treatment plant went into more detail, envisioning 95 modules totaling 270,000 tons in weight. These included 18 CO2-removal modules, eight compression modules, three chilling modules, a power plant, utilities and other buildings. Moving all that equipment to the North Slope would require logistical skills — and spending — reminiscent of the trans-Alaska oil pipeline construction almost 40 years ago.

The gas treatment plant cost numbers used in this report come from filings with FERC by Denali and the earlier ExxonMobil/TransCanada projects, which were both larger in capacity than the plant proposed for the current LNG project.

Pipeline to Prince William Sound or Cook Inlet

The South Central LNG team says the line would be 42 inches in diameter and, like the trans-Alaska oil pipeline, about 800 miles long. The pipe would be buried along most of the route, with trenching and pipe-laying work limited to winter when the frozen ground can support heavy equipment.

For much of the route, depending whether it ends at Prince William Sound or Cook Inlet, the gas pipeline would roughly parallel the oil line. The project team's last public statement on the liquefaction terminal site was that they had narrowed the list to four possible sites; no locations were provided.

The pipeline would be designed to move as much as 3.5 bcf of gas a day, making it the largest gas pipeline in North America. The line would require up to 1.2 million tons of steel. The gas would be pressurized for the ride to tidewater at more than 2,000 pounds per square inch, requiring thick-wall pipe.

The earlier TransCanada/Exxon proposal for a similar pipeline to Valdez estimated the cost at $11 billion to $14 billion.

LNG storage tanks

The project team says two storage tanks would be built at the liquefaction terminal, each capable of holding about 3.5 billion cubic feet of gas in the form of LNG, maybe a day and a half's production from the liquefaction plant and enough to fill a good-sized tanker.

The companies have not provided any costs estimates for the tanks — and no LNG tanks were proposed for the earlier Denali or TransCanada/ExxonMobil projects to move gas to North America by pipeline — but recent LNG storage projects in Singapore and Greece provide a range for possible costs.

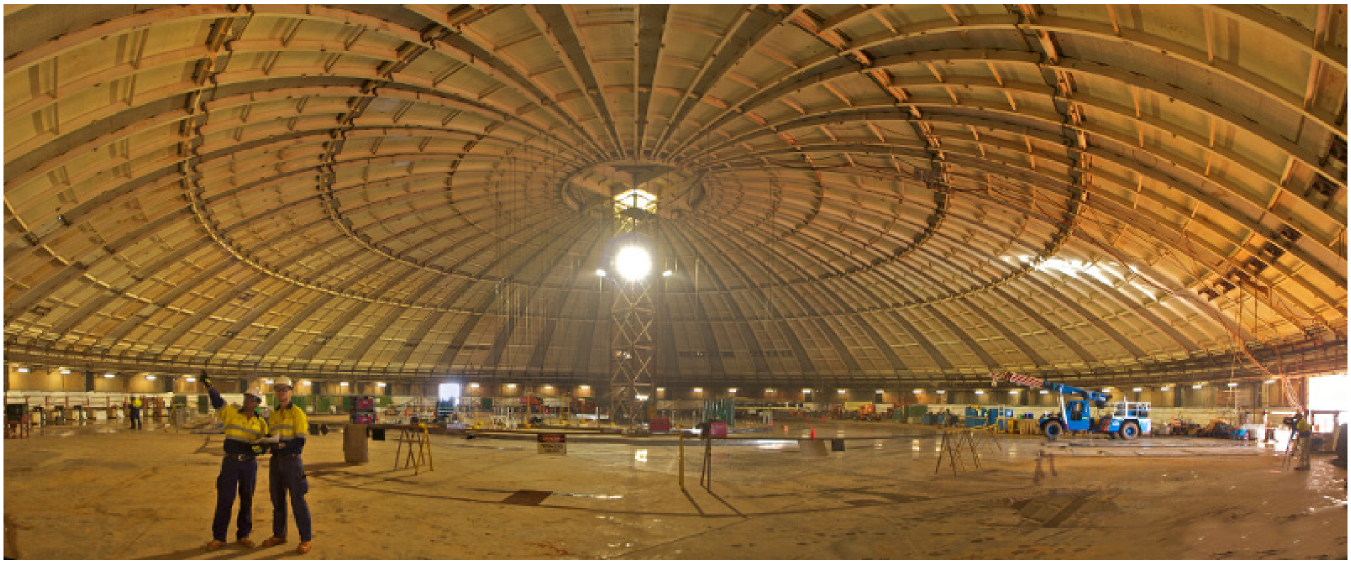
A Greek company last year advertised for bids for construction of an LNG storage tank about one-third smaller than the tanks proposed by South Central LNG, with the cost estimated at $150 million.

Singapore LNG Corp. is considering a huge storage tank for its receiving terminal, more than 50 percent larger than the tank proposed for the Alaska project. The company estimates the tank could cost around $500 million.

ALASKA LNG NOT ALONE IN HIGH COSTS

When it comes to Alaska natural gas project ideas, today's South Central proposal is the latest in a series running back 40 years. The first was floated before construction of the oil pipeline, in the dawn of Alaska's North Slope oil boom.

The Arctic Gas project, as it was called, envisioned a 4,512-mile gas pipeline system running east from



Source: Chevron

Each storage tank under construction at the Gorgon LNG project in Australia will be able to hold a tanker load of supercooled gas, waiting for shipment to overseas customers.

Prudhoe Bay to Canada's Mackenzie River delta and then south to markets in Canada and the United States. As of 1975, it was estimated to cost "only" $6.7 billion. Still, that's equivalent to about $29 billion in today's dollars, the first sign that no North Slope gas project was ever going to be cheap.

Fast-forward to the South Central project. ExxonMobil, BP and ConocoPhillips hold rights to most of the known natural gas resources on the North Slope, while TransCanada is the largest natural gas pipeline operator in North America.

What about that gigantic price tag of $45 billion to $65 billion? At the top end, it's more than five times Alaska's current annual state budget. At that price, does it leave Alaska with a realistic shot at the world market?

As it happens, numbers in that ballpark come up with some regularity around the globe.

Last year, a CNN Money survey of the 10 most expensive energy projects in the world included five liquefied natural gas projects expected to cost more than $30 billion each.

Topping the list of such projects was Gorgon with its $52 billion price tag. Located off Australia's coast, it's under development by Chevron, ExxonMobil, Royal Dutch Shell and a couple of Japanese utilities. It's similar in output capacity to the Alaska project, maybe a bit smaller. One substantial difference is that gas field development costs are included in Gorgon's $52 billion price tag. Construction is under way, with first gas expected in 2015.

Source: Chevron

The export jetty and berths for the Papua New Guinea LNG project, outside Port Moresby. The plant is expected to ship its first gas in 2014.

Because of their huge size, LNG projects — those of Alaska and its competitors alike — will require, first, huge markets to absorb their output, and, second, a solid likelihood that gas prices in those markets will remain high enough over the life of the project to make it profitable, ideally in the form of long-term contracts.

A Deutsche Bank Markets Research report last year forecast it would take 13 years of operation before Gorgon LNG turns positive cash flow. It referred to an earlier Australia LNG project, North West Shelf, that the bank said took 20 years to get to positive cash flow for its developers.

CAN ALASKA GAS COMPETE?

Growing LNG demand in Asia is the opportunity that attracts gas producers to invest in megaprojects. Certainly, the cost of construction is an issue in an increasingly competitive marketplace. But the real price that matters is the cost of LNG landed at the dock in Japan, South Korea, China and elsewhere in Asia. That's the sum of producing the gas, moving it to a liquefaction plant, turning it into LNG and delivering it by tanker.

Some analysts think Alaska may have something of an edge over its rivals because it is closer — meaning shorter tanker runs and fewer tankers needed — to Japan and some of the other Asian markets. The U.S. Gulf Coast, East Africa and Qatar are much farther away than Alaska.

In addition, Alaska's North Slope gas production costs likely would be lower than undeveloped fields in the remote regions of British Columbia, coal-seam plays in Australia and isolated fields in Russia's Arctic. This is because much of the Alaska infrastructure — including wells — needed to produce gas has already been put in place for development of the North Slope oil fields.

Also worth noting is that Alaska gas largely escapes two issues complicating the issue of LNG exports from the Lower 48.

One is the process of hydraulic fracturing for getting gas out of shale rock. Fracking has raised concerns about possible contamination of drinking water supplies in the Lower 48. A reduction in fracking activity would likely mean a reduction in Lower 48 gas production, which could reduce the amount of gas available for export as LNG.

While fracking has gone on for years on Alaska's North Slope and may increase in the future, few people live in the area compared to shale gas plays in Pennsylvania and elsewhere in the Lower 48 states. In addition, the state is developing regulations that attempt to allay many of the concerns raised by fracking in the Lower 48. To date, hydraulic fracturing has not become controversial in Alaska.

The other Lower 48 issue is the concern that exporting LNG will reduce domestic supplies and raise natural gas prices for consumers there. But Alaska's North Slope gas is so far from Lower 48 markets that nearly four decades of effort have not found a way to get it there at a competitive price. Thus, sending it to Asia instead is unlikely to affect supplies or costs in other states.

The competiveness of North Slope gas in Asia comes down to price. It's not the only factor, but it's a big one. A senior gas analyst at the International Energy Agency told a Canadian newspaper this spring, speaking of the rush of proposed LNG exports worldwide: "Certainly the companies involved will be keen to see their projects moving forward but not under any condition. These projects must be competitive and make sense from an economic point of view."

FERC filings on North Slope natural gas projects

Most cost details available on Alaska gas line projects come from two public filings with the Federal Energy Regulatory Commission.

Both were submitted in 2010 by sponsors of previous projects before holding what is called an "open season." An open season starts when project plans are made public, after which interested gas shippers bid on how much gas they'd like to move through the system and how much they'd be willing to pay to do so.

An open season is generally the make-or-break point for any natural gas transmission project, and neither of the two that filed with FERC announced the responses they received nor any signed contracts. One has closed down and the other is on hold.

The first project to submit an open-season filing was called the Alaska Pipeline Project and was a venture of TransCanada and ExxonMobil. The filing came in January 2010 and proposed two alternatives: an overland pipeline through Canada, or a pipeline to Valdez for export. Let the market decide which project was needed, the sponsors said.

The LNG version would have consisted of a Point Thomson pipeline, a Prudhoe Bay gas treatment plant and a pipeline to Valdez. It did not, however, include a liquefaction plant or shipping terminal. Those components, the sponsors said, would be built by third parties. TransCanada said it really wasn't interested in taking the lead to build and operate an LNG plant.

The pipeline to North American markets also included the Point Thomson stub and Prudhoe Bay gas treatment plant.

The partners spent a couple of years preparing for FERC's environmental review process for the line to serve all of North America, but put it on hold in March 2012, acknowledging that soaring shale gas production in the Lower 48 had killed the need for the line.

The second project to file — in April 2010 — was the Denali project, of BP and ConocoPhillips. It was a pure overland project, relying on a pipeline from Prudhoe through Canada to get the gas to market. Accordingly, it included a Point Thomson pipeline and a gas treatment plant. LNG was not an option. Denali shut down in May 2011, pointing to the same market conditions as the ExxonMobil/TransCanada venture.

For more information, please visit our website: www.arcticgas.gov

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