ALASKA NATURAL GAS TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

Canada hopes LNG exports can re-energize gas production

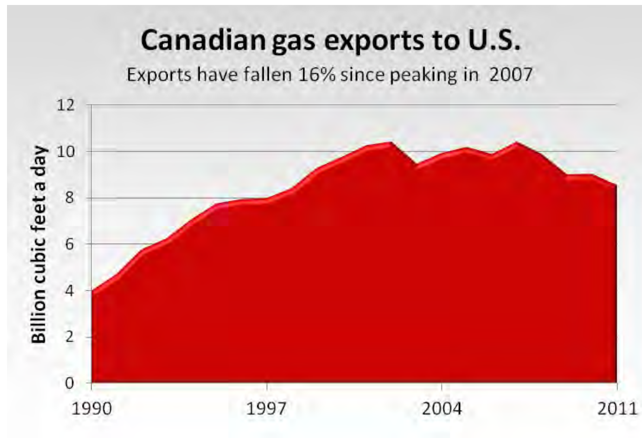
Liquefied natural gas exports from Western Canada to Asia could reignite the excitement that swirled around the nation's promising shale gas plays just a few years ago.

Those plays include Montney, Horn River and Liard — large swaths of northern British Columbia endowed with trillions of cubic feet of natural gas squeezed inside layers of tight shale and fine-grained sandstone.

Those plays promise to raise British Columbia's natural gas profile from minor actor to major star — some day. But today they're struggling for attention.

The glut of Lower 48 shale-gas production not only has sidetracked plans to pipe the rich trove of Alaska North Slope natural gas to U.S. consumers, it has slowed expansion of Western Canada's gas production into the remote new plays.

With U.S. gas supply growing faster than demand, the need for importing Canadian gas is getting pushed to the sidelines. Companies are slashing budgets to drill wells and develop Canada's frontier plays. The risk-reward tradeoff for investment just is too unfavorable when wellhead prices for Western Canada gas are even more depressed than prices for U.S. production due to the higher cost of piping Canadian gas long distances to U.S. buyers.



Source: Canadian Gas Association

Source: Kitimat LNG

Rendering of the proposed Kitimat LNG export terminal in Kitimat, British Columbia.

But out of this woe the industry is reorienting itself to Asia markets, where high LNG prices look as irresistible as an opposing team's empty net at the close of a tight hockey game. The goal: Export a substantial volume of new production that otherwise could remain idle for many years awaiting improved U.S. markets.

At least five Canadian LNG-export projects are getting serious looks. The players include big and small gas producers, pipeline companies, Asian buyers, Japanese and Chinese investors, and at least one First Nations tribe.

Backers of these projects have discussed exporting as much as 43 million metric tons of LNG annually — an average of 5.8 billion cubic feet a day — by early in the next decade. That volume would vault Western Canada into the top echelon of global LNG makers.

However, few believe all of that export capacity will be built. At the moment, two of the projects hold recently issued government licenses to export LNG, but no project has all the environmental and other authorizations needed — or locked-in customers. And none is so far along that the developers have unequivocally committed to building them — known in the business as receiving a "final investment decision."

Two developers separately are considering building their LNG export plants near Prince Rupert, British Columbia, just south of Alaska.

The other three, which appear to be further along in their pre-construction planning, have targeted an obscure port town called Kitimat, about 75 miles southeast of Prince Rupert.

The unique circumstances of Kitimat's birth in the post-war Canada of the 1950s garnered the town some international fanfare at the time — and even a visit from a British royal. But harder times have befallen the town in recent years, and city leaders have pinned their hopes in part on welcoming LNG.

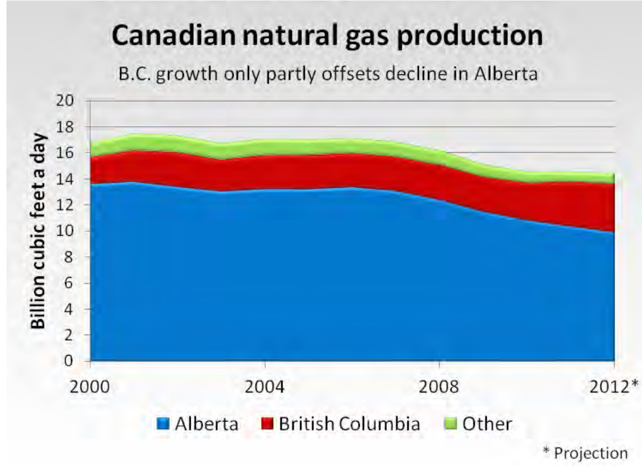
INTO REMOTE BRITISH COLUMBIA

A new report on the potential economic impact of exporting Horn River shale gas as LNG sums up the possibilities simply: "The opening of Pacific Access enhances Canada's ability to exploit its substantial resources," the Canadian Energy Research Institute wrote in its white paper.

CERI pegged the gross-domestic-product impact to British Columbia at $152 billion over 25 years if Horn River leaps into rapid development as an LNG export play. High-income jobs, government revenue and big netbacks to producers from lofty LNG prices account for most of that predicted wealth.

The Horn River shale holds an estimated 144 trillion to 600 trillion cubic feet of natural gas, a volume roughly akin to the estimated gas resource in Alaska's onshore and offshore Arctic. It's unclear how much can be profitably produced — the amount will depend in part on how much markets will pay for the gas — likely just a small fraction of the total resource. One estimate says the shale will yield perhaps 78 tcf of gas — double the proved reserves at Prudhoe Bay and other onshore fields in Alaska's Arctic.

Some production already is occurring at Horn River. The most active company, Apache Corp., started its first 16-well pad in 2010. By the end of that year, Apache and other companies were producing 390 million cubic feet



Source: Canada National Energy Board

a day from Horn River — somewhat more than the daily production from Alaska's Cook Inlet Basin near Anchorage. Apache is one of the companies pursuing an LNG export project.

On a map, the Horn River play doesn't look very remote. It lies in extreme northeast British Columbia, around and north of the town of Fort Nelson. Immediately to the west lies the Liard Basin, where Apache in June announced that its properties might hold an impressive 48 tcf of marketable gas.

The Alaska Highway bisects the Liard. Anyone who has driven that stretch of the road knows it winds through a sparsely populated land of boreal forests, tundra and muskeg. Some remote roads built for logging are drivable only in winter, when they're frozen.

The great British Columbia and Alberta oil and gas fields lie to the south and southeast. Extending sufficient roads and pipelines into the Liard, Horn River and

Source: Apache Corp.

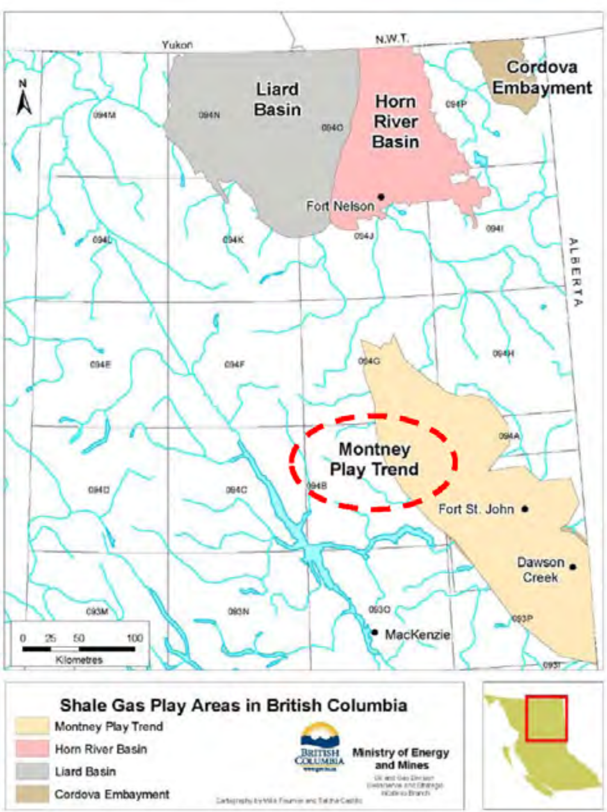
An Apache Corp. drill site in the Horn River basin.

Cordova Embayment, another shale prospect east of Horn River, will cost hundreds of millions, as will building production pads and drilling wells. CERI estimates a fractured Horn River horizontal well costs $7 million to $10 million, more expensive than at other North American shale plays.

As shale plays go, Horn River has its attractions. Although it's relatively deep underground — 8,000 to 13,000 feet down — the shale is thick, 360 to 580 feet of play. And production from early wells has slumped much more slowly than in typical North American shale plays. A new Horn River well might produce half as much gas on day 365 as it does on day 1, CERI says.

"The key constraints faced by producers include low gas prices, a short drilling season, lack of existing infrastructure (pipelines and roadways), produced carbon dioxide (about 12 percent of the gas is CO2, which must be removed before piping the gas), and emerging water issues," CERI says.

Without bigger market prices to justify development costs, the gas essentially is stranded in the ground, and dreams of a big gross-domestic-product payday are just dreams. Similar barriers have handicapped development of Alaska's North Slope gas for 40 years.



Source: British Columbia Ministry of Energy and Mines

PRICING PEAKS AND VALLEYS

A few years ago, North American gas prices *were* much higher, and the natural gas industry was on fire.

From 2005 through 2008, prices averaged $7.81 per million Btu (about 1,000 cubic feet) at the Lower 48's Henry Hub — almost three times higher than today's depressed price. Expensive, hard-to-get gas deposits suddenly looked more alluring. Those high prices triggered the Lower 48 shale-gas boom and revived interest in an Alaska gas pipeline.

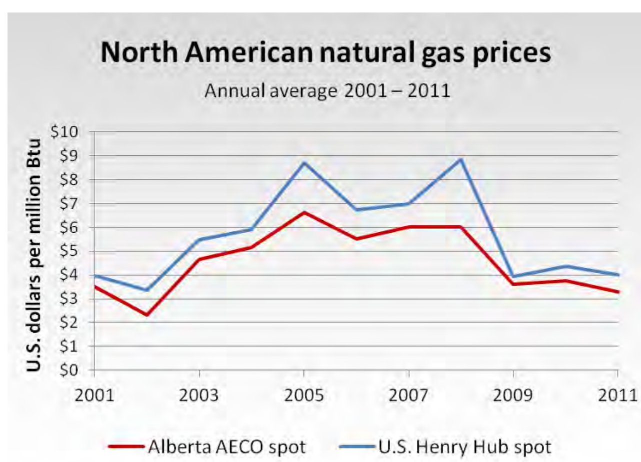
In northeast British Columbia, a land rush erupted.

In 2007, companies paid a breathtaking $1 billion in bonuses for petroleum and natural gas rights in B.C., almost all of it for shale plays.

The next year — as natural gas prices peaked — a frenzy broke out. Companies paid a record $2.7 billion in bonuses, including $1.1 billion in Horn River bonuses and $1.3 billion for Montney rights.

Over the next two years, 2009 and 2010, gas prices slid, and so did the bonuses, totaling $1.7 billion for shale regions. The Liard and Cordova Embayment plays got noticed those years — Liard bonuses totaled $158 million and Cordova reaped $261 million.

Then North American gas prices plunged, and northeast B.C. got quiet. Horn River netted $2.9 million in 2011. Liard and Cordova got nothing.



Sources: Natural Resources Canada, U.S. Energy Information Administration, Office of the Federal Coordinator research

ASIA INVESTORS COME CALLING

With North American markets fading from view, northeast British Columbia oil and gas companies came to embrace Asia as the destination that would pay them enough to justify developing their shale properties.

In 2010, LNG prices averaged $10.91 per million Btu in Japan, according to the BP Statistical Review of World Energy. Last year the price leaped to $14.73, with some spot cargo shipments grossing much more than that. Japanese utilities clamored for more LNG and other fuels after the 2011 earthquake and tsunami shut down the nation's nuclear power plants.

New players from Asia started investing in Canada, too, hoping to diversify their portfolios and possibly secure Canadian supply if LNG exports occur:

- Mitsubishi formed a gas joint venture with Canadian producer PennWest in May 2010.
- Malaysia's national oil company PETRONAS entered into a gas joint venture with Canada's Progress Energy in June 2011 then a year later reached a deal to simply acquire its partner.
- Late last year China's Sinopec and Japanese energy companies INPEX and JGC Corp. made deals in Canadian gas development projects.
- Early this year, PetroChina bought gas assets from Shell, and Mitsubishi formed a second gas JV, this time with Canadian producer Encana.
- In July, China National Offshore Oil Co. — known as CNOOC — proposed a friendly $15.1 billion takeover of Calgary-based Nexen, subject to government approval. Nexen's holdings include rights in the Horn River, Cordova and Liard basins.

THE POSSIBLE LNG PROJECTS

Ideas for LNG export projects followed swiftly. As yet, all are well short of starting construction.

Kitimat LNG

In December 2010, a partnership called Kitimat LNG — sometimes called KM LNG — applied to Canada's National Energy Board for a license to export up to 10 million metric tons of LNG annually for 20 years — an average of about 1.3 billion cubic feet a day.

Possible Canadian LNG projects

KM LNG (Kitimat LNG)
Apache, EOG Resources, Encana
$15 billion plus $1.1 billion pipeline. Up to 1.3 billion cubic feet a day capacity.
BC LNG
Cooperative of gas producers, marketers, Haisla Nation
$450 million. Up to 240 million cubic feet a day of capacity.
LNG Canada
Shell, Korea Gas, Mitsubishi, PetroChina
$12 billion, plus $4 billion pipeline. Up to 3.2 billion cubic feet a day of capacity.
PETRONAS/Progress Energy
PETRONAS and Progress Energy
$10 billion. Up to 1 billion cubic feet a day of capacity.
BG Group
BG Group
Cost and volume are undetermined.

The partners are Apache, Encana and EOG Resources, another Canadian producer. Their project could cost as much as $15 billion. The three companies also propose a $1.1 billion, 36-inch diameter, 287-mile pipeline from an existing gas trunkline in central B.C. to Kitimat on the west-central coast.

BC LNG

In March 2011, the NEB received its second export-license application, from a group known as BC LNG. The cooperative's founding members included producers, gas marketers and the Haisla Nation, a local First Nations tribe in the Kitimat area.

BC LNG applied to export 1.8 million metric tons a year — about 240 million cubic feet a day. That's small, roughly the capacity of the ConocoPhillips LNG plant in Nikiski, Alaska, the United States' only export plant. BC LNG would anchor its liquefaction plant on barges down Kitimat Arm from town, but closer to the city than the proposed Kitimat LNG terminal. Development costs have been pegged at under $500 million.

LNG CANADA

A third export application came more recently, in July 2012. If fully realized, the project would dwarf the size of the other plants combined.

LNG Canada is a venture of Shell, Korea Gas Corp., Mitsubishi and PetroChina. It asked for a license to export from Kitimat up to 24 million metric tons a year — 3.2 bcf a day on average. Half of that LNG capacity would be ready around 2020, with the rest starting up as soon as possible afterward.

Connected to the LNG Canada proposal, TransCanada Corp. in June announced plans for a $4 billion, 435-mile pipeline from the Montney, Horn River and Cordova basins to Kitimat.

PETRONAS/Progress Energy

Separately, Malaysian oil company PETRONAS, which has properties in Western Canada and a pending takeover of Progress Energy Resources, said it is nearing completion of a feasibility study for an LNG project, with exports starting as early as 2018.

In June, PETRONAS and Progress disclosed they're studying a site on Lelu Island outside Prince Rupert for an LNG plant. A 7.2 million metric tons a year plant would cost about $10 billion, according to trade publications.

BG Group

International natural gas company BG Group reportedly also could put an export plant near Prince Rupert.

On Sept. 10, 2012, Spectra Energy, a major British Columbia gas pipeline company, said it is working with BG Group on a project. Spectra said the two companies are beginning to plan a 525-mile high-volume gas pipeline from northeast British Columbia to Prince Rupert to supply a BG export plant, possibly by the end of this decade.

As yet, BG has no Canadian gas production, according to one report.

None of these projects is anywhere near breaking ground.

None has announced signed contracts with LNG buyers in Asia — typically gas and electric utilities.

Provincial and federal environmental assessments need to be completed for pipeline stream crossings, air emissions, the plant sites themselves and other work. And the projects will need other authorizations. As CERI put it in its new report on exporting Horn River gas as LNG:

> "On the federal level, an LNG facility must satisfy agencies such as the Canadian Environmental Assessment Agency, Transport Canada Marine Safety Navigable Waters, Transport Canada Environmental Affairs Environmental Programs, Transport Canada Marine Security, Transport Canada Marine Safety Compliance and Enforcement, Fisheries and Oceans Canada, Environment Canada and the NEB. On the provincial level, an LNG facility must gain approval from provincial Utility Commissions and the provincial environmental assessment offices and transportation ministries."

With understatement, CERI called LNG permitting "a drawn-out process."

WILL ASIA WANT CANADIAN LNG?

Two projects already have their NEB export licenses, allowing the gas to leave Canada as LNG.

Apache-led Kitimat LNG won its license last October, the first the NEB ever awarded.

Source: Nexen Inc.

A Nexen shale gas site in northeast British Columbia.

BC LNG's license came in February 2012.

The NEB took 10 to 11 months to consider each application.

A passage in its Kitimat LNG decision sums up the NEB's opinion of the value of LNG exports:

> "The Board is of the view that the proposed export will not only open new markets for Canadian gas production, but that ongoing development of shale gas resources in BC and Alberta will ultimately further increase the availability of natural gas for Canadians."

The NEB struck a similar note in its decision on the smaller BC LNG project. BC LNG sponsors argued "that current market conditions require Canadian producers to find new markets in order to continue developing their reserves. BC LNG argued that the proposed export would help avoid natural gas being shut-in when North American prices are insufficient to justify production."

The NEB acknowledged the point: "The Board understands that significant changes are occurring in the North American natural gas market as changing supply sources and emerging demands alter inter-regional natural gas flows. In particular, growing US supplies are increasingly entering markets in central Canada as well as US markets traditionally accessed by Canadian gas exports."

The three applicants that have taken their projects to the NEB so far have spiked their filings with favorable market assessments from international energy consultants. Kitimat LNG used Poten & Partners. BC LNG used Wood Mackenzie. And this summer the Shell-led LNG Canada used PFC Energy.

All three analyses basically came to the same conclusions:

- U.S. export markets are shrinking for Western Canada producers.
- The oil-linked Asia LNG price should remain much higher than North American prices for decades.
- The big Asian LNG buyers — Japan, South Korea, Taiwan and China — will need to lock in new supplies as their gas demand grows and old contracts expire.
- Those buyers will find attractive Canada's ample supply of gas, political and regulatory stability, and relative proximity to Asia.
- Canadian projects will compete for Asian LNG supply contracts with projects in Australia, Papua New Guinea, the U.S. Gulf Coast, Africa and elsewhere. But not all of the proposed projects will materialize.
- The winning projects will be the early movers that lock up Asian buyers first.

That "act now because the window is closing" theme will ring familiar to Alaskans who have followed proposals over the decades to liquefy North Slope natural gas.

CERI's projection of a big gross-domestic-product windfall is predicated on Asian LNG prices remaining sky high. CERI estimated Western Canada production could be delivered to Asia for $8.60 per thousand cubic feet ($0.60 for pipeline tolls to the coast, $6 for liquefaction, $1.50 for shipping across the ocean and $0.50 for LNG regasification in the destination country). That $8.60 excludes costs of leases, exploration and development, taxes and royalties, and a profit for the gas producer.

(Wood Mackenzie last year estimated a similar cost for exporting Alaska North Slope gas as LNG. The big North Slope producers — ExxonMobil, ConocoPhillips and BP — jointly are in the early stages of considering an Alaska LNG project.)

Whatever price the LNG fetches in Asia above $8.60 would accrue to the Canadian gas producer to cover its costs and as its "netback." CERI assumed an Asian LNG price of $13 to $16, providing a large netback.

PFC Energy's new market analysis for the Shell-led project said a tanker trip to Japan from Kitimat would take eight to 10 days. That's longer than the six-to-eight-day trip from Australia but much shorter than the 13-to-15-day trip to Japan from Qatar, the world's largest LNG maker. A shorter trip saves millions of dollars a year in cargo costs.

WHY KITIMAT?

This brings us back to Kitimat, the little industrial port town that could.

Three of the four Canadian LNG plants under discussion would call Kitimat home.

Kitimat first strutted onto the LNG stage as a possible site of a LNG import terminal. That was eight years ago. Similar import-terminal plans arose across coastal

North America. Some were built — billions of dollars worth. They mostly stand idle today, although owners of many have applied to add liquefaction plants so they can start exporting LNG.

But for Kitimat, the shale-gas boom killed its import project before the land got cleared. After a series of ownership changes in 2010 and 2011, Apache, EOG and Encana controlled the project, and they were talking exports, not imports.

If even one of the three proposed Kitimat projects gets built, it would be a boon to the town.

Source: en.wikipedia.org.

Aerial photo of Kitimat shows the Rio Tinto Alcan smelter in the background.

Kitimat's population had shriveled to an estimated 8,335 residents as of 2011, down 35 percent in 30 years. Fifteen percent of the town's private dwellings were unoccupied last year, according to Canadian census figures.

The town lost its methanol plant in 2005 because of high North American gas prices and its pulp and paper mill in 2010. The 58-year-old aluminum smelter remains the big employer. Ships delivering the plant's raw material and carrying away finished ingots ply the port — one of the few deep-water ports on Canada's West Coast.

Kitimat sprouted out of old-growth forest in the early 1950s as the British Columbia government sought to diversify and expand its post-war economy.

On Dec. 30, 1950, the government signed a deal with Aluminum Company of Canada to develop a hydroelectric project that would supply cheap energy for a new Alcan smelter — the world's largest — at a brand new town on the B.C. coast.

Between 1951 and 1954, thousands of construction workers cleared wilderness tracts and built a dam, tunnel, powerhouse, transmission line, smelter ... and a town ... in a broad coastal valley that offered room for the smelter, residents and other industry that might want to locate there.

Kitimat, a Native term meaning "people of the snow," became Canada's first totally planned community and, in 1953, first B.C. town without actual residents to be incorporated, according to a history on the Royal BC Museum website.

The town was an island of 1950s suburbia planted in the wild. An Alcan executive described the mission: "We are interested in building neither palaces nor monuments, but are extremely anxious to avoid a shack town."

To accelerate construction, the houses were prefabricated, shipped to the site and assembled there. An early resident recalled that the initial houses were ill-suited for the climate: "You would have a house that would probably be suitable in Santa Clara (California)," he said. "The roofs were three-quarter cathedral ceilings, therefore they had virtually no insulation and an aluminum roof. And when it rains in Kitimat ... it just thundered on the roof. After a while it would lull you to sleep."

In 1954, the first residents moved into the houses, and the Alcan smelter opened. The event was such a celebration that Prince Philip, Queen Elizabeth's husband, showed to tap the first ingot poured.

Figure 1-2
Proposed Terminal Location in Douglas Channel

Source: Canada National Energy Board

Trains arrived in 1955, and a road linking Kitimat to the B.C. highway system opened in 1957. The road was a mess at first; in fact, the first car was dragged the last five miles or so by a D9 Caterpillar, according to the Royal BC Museum account.

Alcan turned the town and its homes over to residents as quickly as possible. Locals installed such community services such as schools, police, fire, and a hospital. The Kitimat Works Sports Association soon got active — yes, hockey. A rod and gun club and a yacht club also formed.

Kitimat — as a paragon of post-war, can-do Canada — gave officials a reason to crow. National Geographic magazine featured the town in 1956. Two years later Canada highlighted the town in a display at the 1958 Brussels World's Fair.

The aluminum smelter, now run by Rio Tinto, has expanded and modernized. But besides the now-closed methanol/ammonia plant and pulp/paper mill, other industry never really materialized.

The population peaked in 1981 at 12,814 residents.

City leaders tout Kitimat's low-cost power, deep-water port and rail connection. Besides the LNG projects, a separate but controversial project is afoot to export product from Alberta's oilsands to Asia.

"Kitimat is one of Western Canada's emerging energy hubs. LNG export, natural gas liquid handling, bitumen export, condensate import, co-generation power facilities, aggregate processing and new hydro projects are in place or under discussion," the city's website boasts.

"Realization of one or more of the largest of these investments could bring positive economic change to the economies of British Columbia and Canada, as well as to northwestern BC."

Canadian politicians generally support LNG exports.

The B.C. government in June decided it will redefine natural gas as a clean energy ... if it's used to power LNG plants. This bucked the long-standing policy of promoting hydroelectric energy use — the 1950s decision to allow Alcan's hydroelectric project to power the company's Kitimat aluminum plant was an early incarnation of that philosophy.

A month earlier, B.C. Premier Christy Clark gushed when the Shell-led LNG Canada group announced its LNG export plans: "This brings us one step closer to having three LNG facilities up and running by 2020, a key target set out in the BC Jobs Plan."

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

Contact information:
Bill White, Researcher/Writer
(907) 271-5246
bwhite@arcticgas.gov

General Questions:
info@arcticgas.gov

Locations:
Office of the Federal Coordinator, Alaska Gas Line
1101 Pennsylvania Ave. NW, 7th Floor, Washington, DC 20004
(202) 756-0179

188 W. Northern Lights Blvd., Suite 600, Anchorage, AK 99503
(907) 271-5209