Australia makes bold move as LNG supplier

The U.S. shale gas boom has scored big headlines in the world of natural gas.

The boom has shattered old understandings of gas pricing, galvanized environmentalists, ignited a national debate over exporting resources, wounded Canadian gas producers, surprised LNG makers in Qatar and elsewhere whose target U.S. market vanished, and sparked a global scramble as countries assess their own shale prospects.

But almost as breathtaking is Australia's major move into liquefied natural gas production.

Australia's third LNG plant sent its first shipment to market in June.

The country's seven other LNG projects under way today total a stunning $170 billion worth of development.

Even that lofty figure understates the extent to which Australia's natural gas industry is mushrooming — it doesn't count billions of dollars in gas-field expansions, gas-pipeline construction and gas-fired power plant building that also are afoot. And it omits the roughly dozen other LNG projects in various stages of consideration.

Australia is expanding the boundaries that define what an LNG project can be.

The world's first floating LNG project has been sanctioned in Australia involving a massive typhoon-resistant factory-ship anchored 125 miles at sea over a remote gas field. The 1,600-foot-long ship being built in South Korea for Shell will cover an area the size of 24 football fields.

Source: Woodside

The Pluto plant opened this year and is Australia's third LNG plant.

Australia also is building the first LNG projects fed by coal-bed methane rather than conventional natural gas. Three such projects are proceeding, with more under discussion.

Fully two-thirds of global LNG capacity under construction is in Australia.

The country is poised to leap from the world's No. 4 LNG producer last year to No. 2 within a few years. Many predict Australia will be LNG's top dog later this decade, dethroning Qatar, which underwent its own audacious tripling of its LNG capacity during the past five years.

In short, Australia is poised to stake its claim to the LNG marketplace that backers of a major Alaska LNG export project and several along the Gulf of Mexico coast want to enter.

Like Alaska, Australia has far more gas than it can consume internally. A conservative estimate of 133 trillion cubic feet of proved reserves is 150 years worth of gas at Australia's current domestic consumption, according to figures from the 2012 BP Statistical Review of World Energy.

Like Alaska, Australia's oil and gas era started with discoveries in the 1950s and 1960s and saw rapid build-out through the 1970s. Like Alaska, oil was easier to bring to market than natural gas, with many remote gas discoveries stranded for decades.

Like Alaska, interest in natural gas development revived in the late 1990s and early 2000s in response to higher prices.

But here the paths diverge.

Australia eyed growing LNG demand, especially in East Asia, and launched a gas-drilling renaissance that discovered dozens of new fields. Big, deep-pocketed western oil companies got involved — Shell, Chevron, ConocoPhillips, ExxonMobil, Total. Gas and electric utilities in Japan and elsewhere joined in.

In some cases, projects won rapid-fire board of director approval. Developers of Pluto LNG in Northwest Australia, which started up this year, committed to the $15 billion project just two years after the field was discovered. For the $10 billion-plus Prelude project being developed entirely offshore, approval came a mere four years after finding the anchor gas field.

BIG PAYDAYS

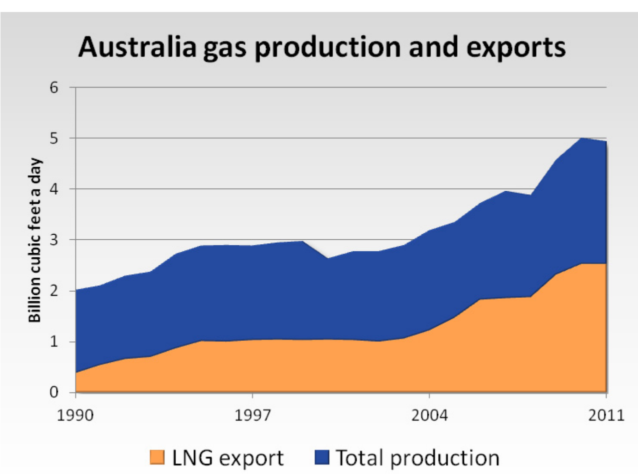
Australia's mad dash into LNG has come with growing pains.

Many projects are late. Some are overbudget. Skilled labor shortages are acute as so many big-ticket projects compete for engineers and heavy-equipment operators.

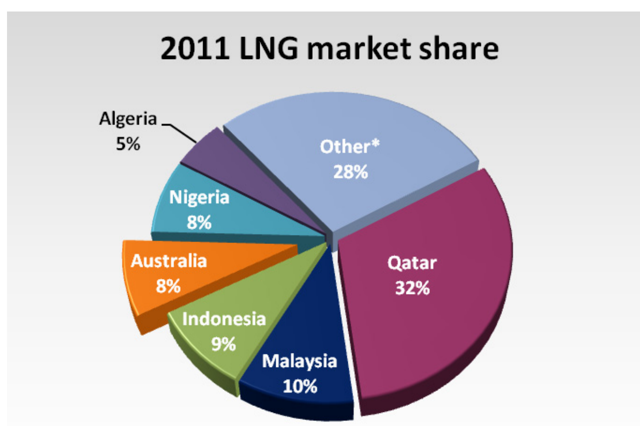
The Pluto LNG plant opened this year 18 months behind schedule and cost $14.9 billion, compared with its original budget of $12 billion.

The Gladstone project expected to open in 2015 was recently repriced at $18.5 billion, up from $16 billion. The cost of the nearby Queensland Curtis project set to start up in 2014 recently grew to $20.4 billion from the $15 billion estimate only two years ago.

Aggravating and possibly helping to explain these challenges is that LNG isn't Australia's only export



Source: Australia Bureau of Resources and Energy Economics



* Trinidad & Tobago, Russia, Oman, Yemen, Egypt, Brunei, Equatorial Guinea, Peru, Abu Dhabi, Norway, Alaska

Source: International Group of Liquefied Natural Gas Importers industry undergoing a growth spurt. Coal and iron-ore mining are much bigger industries in Australia than natural gas, and both are amid their own multibillion-dollar expansions, competing with LNG projects for labor and equipment.

A government official last fall noted the financial boon that's blessed workers willing to relocate to far-flung job sites.

Alan Copeland of the Bureau of Resources and Energy Economics said a run-of-the-mill laborer on a remote LNG project is pulling in wages of $225,000 to $300,000 a year.

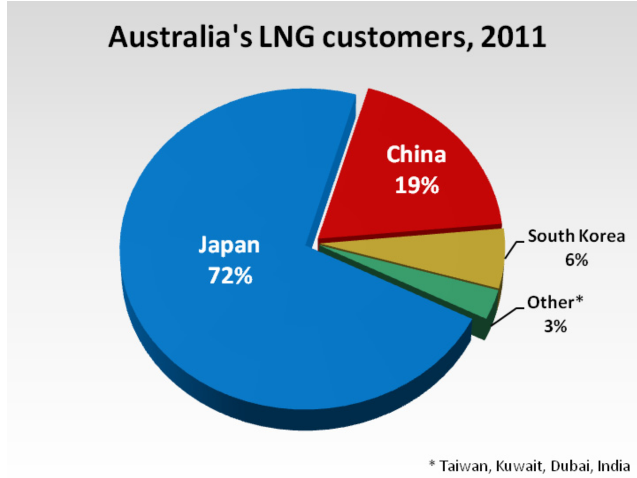
Some remote projects can entail housing thousands of workers in or near towns that previously boasted only a few hundred residents.

Environmental issues are popping up, too. A $40 billion to $50 billion possible development called Browse in Northwest Australia would pipe gas over 200 miles from the offshore gas and liquids fields to an LNG plant that would be built near an environmentally sensitive and culturally important site called James Price Point. Among the issues: Avoiding fossilized dinosaur footprints that track along the coastline. Some traditional landowners greeted with disdain a 2011 agreement with the Aboriginal group Goolarabooloo Jabirr Jabirr designed to help push the project ahead.

Disposal of carbon dioxide, a waste greenhouse gas produced with methane and gas liquids, is an issue for some projects, just as it will be when Alaska's Prudhoe Bay gas reserves get developed. Sponsors of the $52 billion Gorgon project offshore Northwest Australia plan to reinject the CO2 and gave the project their OK only after the government accepted long-term liability for the carbon dioxide after it's injected.

In the more thickly populated east, coal-bed methane — called coal-seam gas thereabouts — will fuel the three LNG projects under way.

But the astounding abundance of coal-bed gas — the government estimates 30 trillion cubic feet clustered in Queensland, more than the conventional-gas reserves at Alaska's Prudhoe Bay — could boomerang on Australia's ambitions to add even



Source: International Group of Liquefied Natural Gas Importers

more LNG projects.

Coal-bed wells are more closely spaced and less productive than conventional-gas wells. More wells mean more water use during production This has riled farmers, who object to the number of wells, the amount of water needed and wastewater disposal plans.

Others warn of disaster as more LNG tankers sail past the Great Barrier Reef en route between Gladstone, the east-coast port that will house all three coal-bed methane LNG plants under development, and customers in Japan, China and elsewhere in Asia.

Some expect a furor if east coast consumers get whacked with higher natural gas prices thanks to exports. LNG will be sold to Asian buyers paying oil-indexed prices, not the currently lower domestic gas prices in Australia. Will coal-bed methane producers start routing their gas to the highest bidder, inflating local prices?

Another problem is that coal-bed field development to support the three LNG projects is behind schedule. Thank Mother Nature in part for that. Construction started during two of Queensland's wettest years in decades — 2010 and 2011. The ground was so sodden developers couldn't access some top prospects.

Reuters recently noted the problems could delay or kill plans for more coal-bed methane LNG plants beyond the three under development today: "Patchy drilling results, rising costs and a world-wide glut of gas threaten to jeopardize what could amount to more than $60 billion of additional investment in liquefied natural gas (LNG) plants, based on current project costs, and leave an industry that would be just half the size its architects once envisaged.

"Instead of exporting 56 million tonnes [metric tons] of LNG a year, as originally planned, the industry may have to stop at 25 million tonnes — the capacity already being built on Australia's northeast coast."

One analyst told Reuters: "'If you join up all these dots: rising costs, technical challenges, regulatory hurdles and pushback from competing communities ... then you have a very poor scenario there.'"

SEVEN PLANTS IN FIVE YEARS

Despite the challenges facing Australia's LNG industry, seven new plants are forecast to be finished within five years.

These plants should have enough capacity to make 60 million metric tons of LNG annually — an average of 8 billion cubic feet of gas per day. That's roughly three times more gas than a large project to process Alaska North Slope gas might export.

By comparison, Australia's two existing plants ran full -throttle last year in making 19.5 million metric tons — 2.6 billion cubic feet a day on average. With the third plant — Pluto — now online, Australia's capacity is about 24 million metric tons.

This new capacity under construction could roughly keep world LNG supply on pace with or ahead of expected demand growth through 2017, according to several analyses.

Beyond that, it's a question mark whether Australia will surge far past Qatar as the world's biggest LNG supplier by expanding production after 2017. (The seven projects will bring Australia's LNG capacity to roughly the same as Qatar's.)

Australia will be a high-cost producer. Adding the cost of installing offshore fields and well as the LNG plants, Australia needs a high oil price to pay off the development costs. So far, oil-linked LNG prices have worked favorably for Australia.

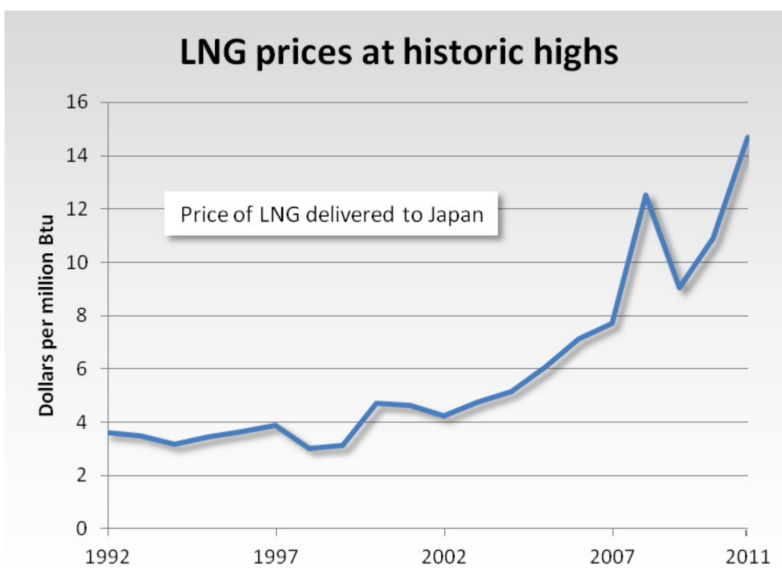
But LNG plants in Alaska, the U.S. Gulf Coast or Canada might be more cost effective for serving the demand growth after 2017, according to one analysis. New discoveries off East Africa — totaling at least 100 trillion cubic feet of recoverable reserves — also could dash Australia's post-2017 LNG expansion hopes.

For now, Australia is playing a strong hand:

- It's rich in natural gas reserves.
- Developers face little risk the country will nationalize their gas fields or LNG plants.
- It's near the big LNG markets of Japan, South Korea, Taiwan, China and India.
- The country welcomes foreign investment, as it's demonstrated over the decades in its mining industry.

Beyond this, Australia has shown it can be relied on to deliver. It's hard to overstate the value of reliability to LNG importers such as Japan, South Korea and Taiwan. They need gas for power production and they have virtually no gas fields of their own.

Since Australian LNG production began in 1989 it has built a reputation as a reliable supplier.



Source: 2012 BP Statistical Review of World Energy

Australia's LNG plants under development

Conventional gas

Gorgon LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length*	Source of gas
Chevron (operator), Shell, ExxonMobil, Osaka Gas, Tokyo Gas Chubu Electric	$52 billion	Barrow Island, off northwest Australia	15 million metric tons per year (about 730 billion cubic feet a year)	1981, 2000	2009	2015	112 miles	Gorgon and other fields off northwest Australia

*** Longest of several pipelines**

Ichthys LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
INPEX (operator), Total	$34 billion	Darwin, Northern Territory	8.4 million metric tons per year (about 410 billion cubic feet a year)	1980, 2000	2012	2017	552 miles	Ichthys field off northwest Australia

Prelude LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
Shell, also Kogas of South Korea is buying into project	$10 billion-plus	Offshore northwest Australia	3.6 million metric tons per year (about 175 billion cubic feet a year)	2007	2011	2016	N/A	Prelude and other fields off northwest Australia

Wheatstone LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
Chevron, Apache, Kuwait Foreign Petroleum Exploration, Shell, Kyushu Electric	$29 billion	Onslow, Western Australia	8.9 million metric tons per year (about 430 billion cubic feet a year)	2004	2011	2016	140 miles	Wheatstone and other fields off northwest Australia

Coal-bed gas

Australia Pacific LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
Origin Energy (operator), ConocoPhillips, Sinopec	$20 billion	Gladstone, Queensland	8.5 million metric tons per year (about 415 billion cubic feet a year)	N/A	2011	2015	N/A	Coal-bed methane

Gladstone LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
Santos (operator), Petronas, Total, Kogas	$18.5 billion	Gladstone, Queensland	7.8 million metric tons per year (about 380 billion cubic feet a year)	N/A	2011	2015	N/A	Coal-bed methane

Queensland Curtis Island LNG

Owners	Estimated cost	Location	Capacity	Key gas discovered	Decision to build	Scheduled to open	Pipeline length	Source of gas
BG Group	$20.4 billion	Gladstone, Queensland	8.5 million metric tons per year (about 415 billion cubic feet a year)	N/A	2010	2014	N/A	Coal-bed methane

DECADES OF FRUSTRATION

Australia's petroleum industry started getting traction in the 1950s, a timeline roughly parallel to the birth of oil and gas development in Alaska and western Canada.

Like Alaska and Canada's Alberta, Australia was a raw, rugged and sparsely populated place.

Only 8.3 million people lived across the vast continent in 1950, roughly the same as New York City's population at that time.

Australia was known to have petroleum resources since its British penal colony era in the early 1800s. Sealers and whalers caulked their ships with bitumen gathered along southern beaches.

But for well over a century the fledgling petroleum industry was largely limited to mining scant quantities of oil shale to feed kerosene manufacturing, with an occasional burst of excitement over oil and gas discoveries that quickly flamed out.

Prospectors targeted oil and gas seeps, and took cues from oily scum in local creeks as well as bitumen beds.

A gas well in the small town of Roma, west of Brisbane, flowed for 10 days in 1906 ... before dying away. A gas and condensate discovery nearby in 1927 ignited a national stock exchange boom ... for a short time.

Concerned about lack of oil resources in an industrial world, the government stepped up to juice the industry.

In 1920, the national government offered 50,000 Australian pounds ($180,000 U.S. in 1920) as a reward for discovery of commercial quantities of oil. In 1936, the Petroleum Oil Search Act made 250,000 Australian pounds (about $1 million U.S.) available to encourage drilling.

Twenty-one years later, new oil-exploration subsidies were enacted, and in 1959 those subsidies were broadened to include seismic and other survey work.

Australia's tax rates

As most everywhere else in the world, Australia's tax and royalty rates are not simple.

First, all corporations earning a profit in Australia pay a flat 30 percent income tax to the federal treasury, with some credits for research and development expenditures.

If the oil and gas production is onshore or in coastal waters, a royalty is payable to the states or Northwest Territory, usually about 10 percent of the net wellhead value.

No royalty is due for offshore production. Instead, most offshore production (there are exceptions) pays a Petroleum Resource Rent Tax to the federal government of 40 percent of net income after project exploration and development costs have been deducted. The government offers significant incentives against the tax for frontier exploration.

There also is federal excise tax on oil and condensate production (not natural gas), ranging from 0 to 30 percent depending on the annual flow. The 0-to-30 range applies to post-1975 discoveries; different rates apply to older fields. And the first 30 million barrels of production per field are exempt from the tax.

-- Larry Persily

TECHNOLOGY BREAKTHROUGHS

It was the increasing sophistication of seismic exploration more than government incentives that really spurred the industry ahead.

Australia's first reflection seismic survey was shot in the Roma area in 1949. Roma lies in the Surat Basin, an area that was to become a keystone of Australia's petroleum development, providing some of the first oil and gas to the Brisbane and Sydney urban areas in the decades to come. It also is at the center of the current coal-bed methane boom that aims to feed at least three LNG plants in the nearby port of Gladstone.

Meanwhile, thousands of miles away, in a remote but geologically promising site on the northwest coast, a joint venture of Standard Oil of California, now called Chevron, and an Australian company called Ampol Exploration was spudding wells. The venture, called WAPET for Western Australian Petroleum, announced in December 1953 that it struck oil with its Rough Range No. 1 well on the northwest edge of the nation. Standard Oil said the discovery well flowed nearly 500 barrels a day, a respectable although not remarkable rate.

Source: Alaska Pacific LNG

ConocoPhillips opened its Darwin LNG plant in 2006.

"This was the first oil flow to have been recorded anywhere in Australia, and it caused jubilation throughout the country. The stock market boomed and leading politicians and newspapers claimed that this could be Australia's most significant development of the 20th century," according to an account of the discovery. "Australia had no domestic production of oil or gas at that time, and the costs of oil imports were a major burden on the economy."

The next year, geologists with the joint venture crossed a channel from Rough Range to conduct basic reconnaissance on Barrow Island. This island was so remote that just two years before the British decided the Monte Bello Islands, about 15 miles northwest of Barrow, would be a splendid site to conduct their first nuclear explosion. The British blew a 25-kiloton atomic bomb, somewhat more powerful than the Hiroshima and Nagasaki bombs.

The geologists were the first civilians to visit Barrow Island since the atomic test.

In the end, the Rough Range prospect turned out to be another duster. But the announcement inspired an expansion of oil exploration throughout Australia.

And it turned out the geologists were on to something.

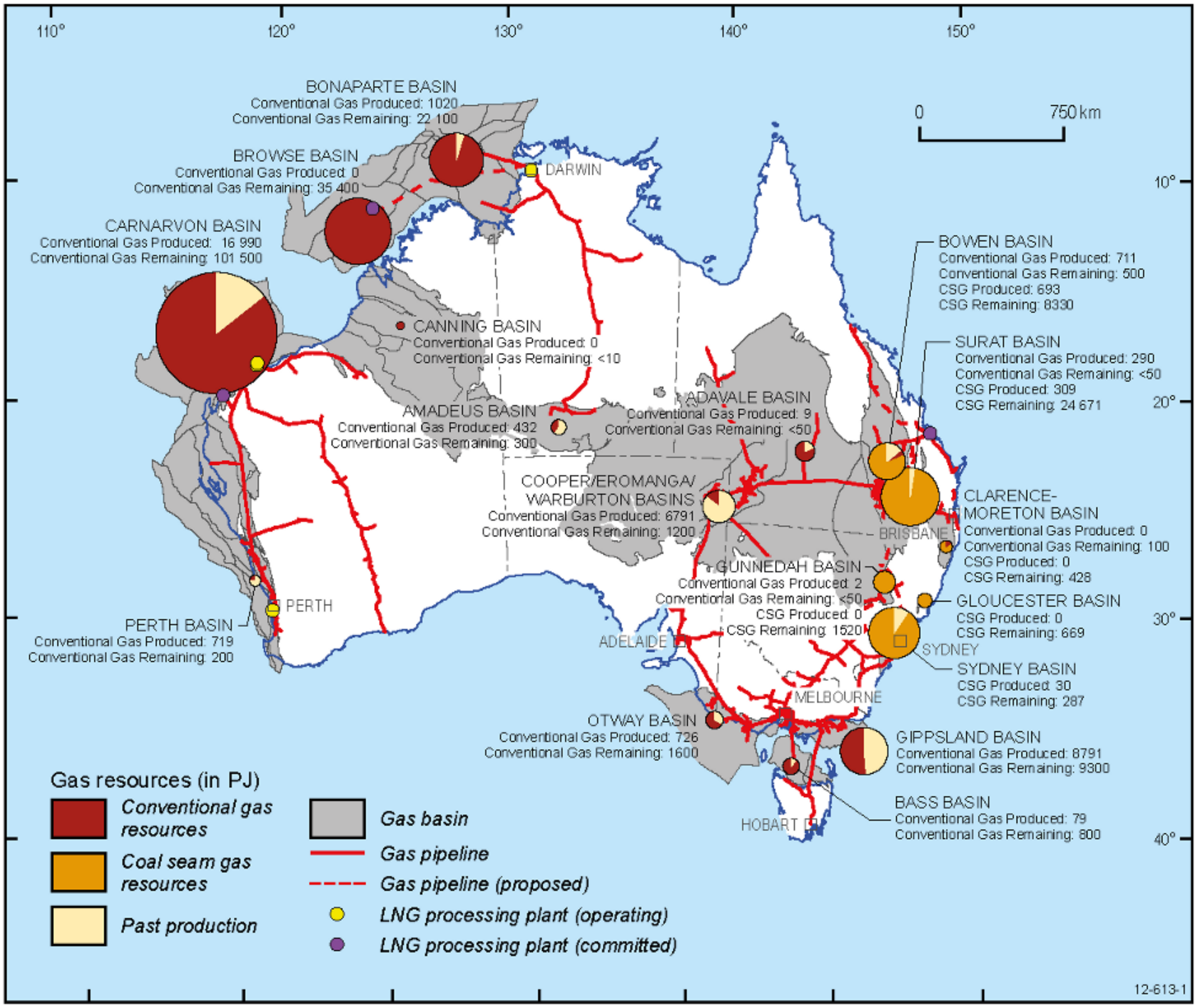
They were prospecting along the southern rim of the mostly offshore Carnarvon Basin. Carnarvon turned out to be one of the world's great natural gas plays, as well as endowed with oil. It hosts the gas fields that supply the North West Shelf LNG plant, the first of the nation's three LNG plants to open, and the Pluto plant that started up this year.

An estimated 92 percent of Australia's conventional gas resource lies in the Carnarvon and nearby Browse and Bonaparte basins. Two of the nation's four big conventional-gas LNG projects under way will tap Carnarvon fields. The other two target Browse fields. Bonaparte is home of the gas field that supplies ConocoPhillips' Darwin LNG plant, which opened in 2006.

Barrow Island is hosting the Gorgon LNG plant under development in the Carnarvon Basin.

THE AGE OF DISCOVERY

Australia's first commercial oil find occurred in 1962



Source: Woodside

A map of Australia's natural gas basins

about 100 miles from Roma. Drillers penetrated the first commercial gas field the next year.

The gas discovery occurred in the arid plains west of Roma on Dec. 31, 1963. The well flowed 2 million cubic feet a day. Excited drillers called in the news to their boss in Adelaide.

After hanging up, the boss exclaimed to a colleague, "Our lives have all been changed."

They recalled a plane flying to deliver parts north to the well. Then they hustled to a liquor store to buy "as much champagne as we believed could go on that small aircraft ... and sent it up to the boys for a celebration on New Year's Eve," one participant recalled.

"Believe me, it was celebrated!" he said. The gas pipeline to Adelaide opened in 1969.

Oil and gas discoveries then cascaded across Australia through the 1960s.

Out in Western Australia, the Standard Oil-led joint venture struck oil on Barrow Island in 1964. Production started three years later, and the find remains one of Australia's most prolific oil fields ever. The Barrow Island discovery started a stampede to drill into the younger formations off the continent's northwest coast.

In the process of this exploration, the Carnarvon Basin was defined as Australia's great oil and gas province.

Although drillers found a bonanza of oil and condensate, their biggest discoveries were disappointments — not oil but vast quantities of natural gas instead.

Unlike oil, there was no global market for natural gas. As for a local market, the northwest discoveries were far from the population centers in southeast Australia. To this day no pipelines connect the Carnarvon Basin to the main cities of Sydney and Melbourne.

Like the great 1968 natural gas discovery at the Prudhoe Bay oil field in Alaska's Arctic, the northwest Australia gas was stranded. Most of it remains stranded today.

But out of these discoveries, Australia's liquefied natural gas industry has bloomed.

NATURAL GAS, NOT OIL

Carnarvon's first monster gas discovery occurred at the North Rankin field in 1971.

A home-grown business named Woodside Oil Co., now called Woodside Energy, hit pay dirt.

Woodside incorporated in 1954 shortly after the Rough Range announcement. The company had been exploring for oil offshore Australia with nothing but frustration since its founding. And it was probing for oil in the Carnarvon when it discovered North Rankin's natural gas and condensate resources instead.

In 1972, Woodside hit another ripper nearby — the big Goodwyn gas and condensate field. The company had found nearly 50 trillion cubic feet of gas — double the estimated reserves at Alaska's Prudhoe Bay. The liquid condensates could be marketed. But what about the gas?

Discovery announcements were coming in thick. Gas and oil were discovered near Perth in 1964. Big interior Australia gas discoveries were ballyhooed in 1964 and 1965, with the gas eventually piped to Alice Springs in the Outback and Darwin on the northern coast. Barrow Island oil production started in 1967. Melbourne got piped gas in 1969 from a southern Australia discovery.

The federal government was scrambling to enact policies that would keep the momentum going, including control of prices.

But Woodside's Carnarvon discoveries were something else. There was way too much gas for local markets; only about 1 million people lived in all of Western Australia, an area that encompasses about one-third of the continent and is not quite twice as large as

Australia's existing LNG plants

North West Shelf

Owners	Cost	Location	Capacity	Key gas	Opened	Expanded	Source of gas
Woodside Energy (operator), BP, Chevron, Shell, BHP Billiton, Mitsubishi & Mitsui, CNOOC	$27 billion	Karratha, Western Australia	16.3 million metric tons per year (about 790 billion cubic feet a year)	1971, 1972	1989	1992, 2004, 2008	North Rankin, Goodwyn & other fields off northwest coast

Darwin LNG

Owners	Cost	Location	Capacity	Key gas	Opened	Expanded	Source of gas
ConocoPhillips (operator), Eni, Santos, INPEX, Tokyo Electric, Tokyo Gas	$3.3 billion	Darwin, Northern Territory	3.3 million metric tons per year (about 160 billion cubic feet a year)	1995	2006	N/A	Bayu-Undan field, Timor Sea

Pluto

Owners	Cost	Location	Capacity	Key gas discovered	Opened	Expanded	Source of gas
Woodside Energy, Kansai Electric, Tokyo Gas	$14.9 billion	Darwin, Northern Territory	4.3 million metric tons per year (about 210 billion cubic feet a year)	2005, 2006	2012	N/A	Pluto and Xena fields off northwest coast

Source: Woodside

Karratha Gas Plant, North West Shelf Project, Western Australia

Alaska. Most people lived around Perth, 1,000 miles south of Carnarvon.

The Western Australia government moved in to assert its rights. Negotiations ensued, resulting in a 1980 contract in which Woodside committed to supply gas to local industries and homes. Today pipelines snake through parts of Western Australia to deliver Carnarvon gas. Perth got its gas in 1984. Mines in the region are the largest gas consumers today.

The startup of gas production and condensate sales, plus Woodside's partnership with deep-pocketed global energy companies, allowed development of the next phase: The North West Shelf plant, Australia's first LNG project.

The Karratha plant started production in 1989, with a capacity of 2.5 million tons of LNG per year, or 334 million cubic feet a day.

The plant since has expanded three times, with its total annual capacity now at 16.3 million tons, or 2.2 billion cubic feet a day. It is one of the world's largest LNG plants — comparable to the export behemoth Cheniere Energy plans to build at Sabine Pass, La., or the project discussed for Alaska's North Slope gas.

The Karratha plant has symbolic value beyond the mere monetizing of stranded Australia natural gas. It demonstrated that Australia's proximity to LNG markets, know-how, reserves and government structures produce a steady, reliable, long-term flow of LNG — qualities highly valued by buyers in Japan, South Korea, China and elsewhere.

Woodside's North West Shelf project paved the path for the company to start up its Pluto plant this year, also near Karratha, and for ConocoPhillips to open its Darwin LNG plant in 2006.

BEYOND 2017

Last year, Australia exported over $10 billion worth of LNG. If prices hold at their current lofty levels, that figure could soar threefold by the end of this decade as new plants open.

But whether Australia's LNG industry can keep expanding beyond the burst of construction now under way is unclear.

The country certainly has the gas resources to expand further.

Woodside, ConocoPhillips and Shell are mulling what to do with the Sunrise field in the Timor Sea, a discovery dating to 1974.

Australian mining giant BHP Billiton and ExxonMobil say they'll decide late this year on the Scarborough field, discovered in 1980.

Plenty of other prospects could fuel the world's expected growing appetite for LNG beyond 2017. The government forecasts that Australian LNG production could reach 107 million metric tons a year — 14 billion cubic feet a day — by 2035, up from about 25 million today and 81 million metric tons after the seven new

Australia's possible future LNG projects

Conventional gas*

Bonaparte

Who's involved	Location	Cost estimate	Possible capacity	Status
GDF Suez, Santos	Bonaparte Basin offshore northern Australia	Undetermined	2 to 2.5 million metric tons per year (about 100 to 120 billion cubic feet a year)	Likely an offshore floating LNG project. Decision expected in 2014

Browse

Who's involved	Location	Cost estimate	Possible capacity	Status
Woodside Energy, BP, BHP Billiton, Chevron, Shell	Fields in Browse Basin offshore northwest coast; LNG plant 35 miles outside Broome, Western Australia	$40 billion-plus	12 million metric tons per year (about 580 billion cubic feet a year)	Project decision expected in 2013

Cash-Maple

Who's involved	Location	Cost estimate	Possible capacity	Status
PTT Exploration and Production	Timor Sea off northern Australia	Undetermined	Undetermined	PTT, the Thailand state oil company, is considering how to develop its recent large Cash-Maple discovery, including possible floating LNG project

Crux

Who's involved	Location	Cost estimate	Possible capacity	Status
Shell, Nexus Energy, Osaka Gas	Fields in Browse Basin offshore northwest coast	Undetermined	Undetermined	Considering how best to develop; could send gas to Shell's nearby Prelude floating LNG

Equus

Who's involved	Location	Cost estimate	Possible capacity	Status
Hess Corp.	Fields in Carnarvon Basin offshore northwest coast	Undetermined	Undetermined	Considering how best to develop; decision possible in 2013; could send gas to existing plant

Scarborough

Who's involved	Location	Cost estimate	Possible capacity	Status
BHP Billiton, ExxonMobil	Field in Carnarvon Basin offshore northwest coast	Undetermined	Undetermined	Decision expended in 2012; could send gas to existing plant

Sunrise

Who's involved	Location	Cost estimate	Possible capacity	Status
Woodside Energy, ConocoPhillips, Shell, Osaka Gas	Fields in Bonaparte Basin offshore northern coast	Undetermined	4.1 million metric tons a year (about 200 billion cubic feet a year)	Government approvals needed. Some gas lies in waters of Timor-Leste, which favors plant in its country; leaseholders prefer floating LNG plant

*** Expansions of existing or under-development LNG plants also possible; some projects listed above could supply gas for expansions.**

Coal-bed gas

Arrow

Who's involved	Location	Cost estimate	Possible capacity	Status
Shell, PetroChina	Gladstone, Queensland	At least $24 billion	8 million metric tons per year (about 390 billion cubic feet a year)	Project decision anticipated in late 2013

Fisherman's Landing

Who's involved	Location	Cost estimate	Possible capacity	Status
China National Petroleum Corp.	Gladstone, Queensland	Roughly $1 billion	3 million metric tons per year (about 150 billion cubic feet a year)	Seeking gas supply before deciding on development

plants open.

But the world teems with excess and stranded gas.

LNG projects from the U.S. Gulf Coast, western Canada, Alaska, Africa and Russia also could compete for customers post-2017. Some forecast that Brazil, Venezuela, Iran and Papua New Guinea will be players, too.

Wood Mackenzie, a global resources consultancy, last year projected that Australia could supply 36 percent of the new worldwide demand for LNG through 2025. Other countries would land the other 64 percent. Wood Mac and other analysts project LNG demand growing 50 to 100 percent during that period.

The Australian government in a 2012 gas resource assessment acknowledged the challenges of further expansion of the nation's LNG capacity:

"There are a number of greenfield projects under consideration (Browse and Arrow LNG), while projects such as Gorgon, Wheatstone, Pluto and the CSG [coal-seam gas] projects under construction in Queensland have the land footprint to add additional capacity.

"The decision to proceed with further projects in Australia will depend on a number of factors including access to sufficient gas reserves, gas prices, project costs and the ability to secure supply contracts for LNG exports."

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

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