ALASKA NATURAL GAS TRANSPORTATION PROJECTS
OFFICE OF THE FEDERAL COORDINATOR

# Financing strategies for LNG export projects

The proposed Alaska natural gas pipeline and liquefaction plant would be one of the largest and costliest energy projects ever built anywhere. Settling on financing for the $45 billion to $65 billion endeavor would be an essential step in bringing gas from the North Slope to market.

The money would be used by partners ExxonMobil, BP, ConocoPhillips and TransCanada to design, engineer and build the facilities needed to move the gas by pipeline to Southcentral Alaska, supercool it into a liquid and finally ship it by tanker to buyers in Asia.

A look at how other large-scale LNG export projects assembled the dollars to pay their construction bills lays out some possibilities for financing a multibillion-dollar project such as Alaska's. This report provides overviews of the financing structures behind five international projects that have arisen over the past decade: Qatargas 2 (Qatar), NLNGPlus (Nigeria), Sabine Pass (United States), PNG LNG (Papua New Guinea) and Gorgon (Australia).

## PROJECT FINANCE

Most LNG export projects use a financing framework common in large-scale, long-term industrial and public facility construction.

Known as project finance, the arrangement allows sponsors to create a separate legal entity to house debt and equity exclusively for the venture. The development's cash flow then becomes the only source of debt repayment, allowing a parent company to shield all or part of its other assets from claims by the lenders.

This financing structure lets borrowers fund major projects without adding debt to their parent companies' balance sheets, and ensures that lenders' money goes exclusively toward the project. Much like toll-road revenues go toward repaying the bonds issued to build a highway, an LNG terminal's revenues would go toward repaying its lenders.

## SOURCES OF DEBT

In financing LNG projects, the mix of lenders, the proportion they lend, the terms they set, and their ranking in the order of repayment vary. Debt can originate with commercial banks; government-backed international lending institutions such as the World Bank or the Asian Development Bank; or bonds issued by the project.

In addition, public and private export-credit agencies, which provide direct financing, loan guarantees or debt insurance, in recent years have ramped up their involvement in lending to LNG export projects. These agencies have been shoring up the share of debt that commercial lenders supplied more readily before the global financial crisis that began in 2007.

Government-run export-credit agencies in particular see the projects as sources of economic growth or of secure energy supplies for their home countries.

## SOURCES OF EQUITY

Borrowed money tends to make up the bulk of financing for most LNG projects, but just as a homebuyer needs to deliver a down payment, developers need to put in their own cash, too.

Sponsor equity can originate with consortia of private companies — as often occurs with costly developments where partners share the risks — and also from partnerships between private companies and national oil and gas companies controlled by the projects' host governments. Each entity takes a percentage of ownership and is entitled to dividends based on ownership share.

Export terminals average about 70 percent debt and 30 percent equity. Those percentages can vary depending on how the gas-sales contracts are structured.

## INTERNAL FINANCING

A confident developer with deep pockets can skip project financing altogether. Instead, it can spend from its own cash flow and borrow against its own assets to build the project.

Companies can budget for the venture through their annual capital spending and also borrow against their balance sheets if their credit ratings are strong enough for lenders to feel comfortable offering favorable borrowing terms. Loans might come from gas purchasers; governments, in exchange for employment guarantees or local purchases of goods and services; government-issued industrial revenue bonds on a company's behalf; or equipment suppliers that want to help finance their own sales to the project.

Companies might opt for internal financing for several reasons. Transaction costs associated with setting up project financing are substantial. Lenders require due diligence; outside consultants and attorneys must be hired; and management must devote valuable time to the process.

Financial independence of internal financing affords sponsors more exclusive control over project decision-making and spending. Lenders in a project finance setup will protect themselves by requiring that they have more direct oversight and require more detailed disclosure of activities to a larger number of parties, including in some cases the public. Lenders will also tie up more sponsor resources by requiring a reserve, known as a "holdback" or "sinking" fund, through which lenders can be compensated should the project encounter unexpected hurdles.

The largest multinational oil companies, which can raise billions of dollars on their own, can go to their balance sheets to fund projects. Most other firms have little choice but to turn to project financing to raise money for costly and complex energy projects.

## RISKS ARE A FACTOR

What ultimately shapes the financing structure is the amount and source of risk involved and the capacity of sponsors and lenders for making the investment and absorbing the risk measured against the rate of return they expect from the LNG project. Some risks may make certain investors skittish while leaving others unfazed.

Possible risks include:

- Project location: Climate, topography, geology, and the lack of existing transportation to a project site could lead to cost overruns.
- Sufficiency of gas supply: Estimates of the gas resource could be overly optimistic.
- Reputation of the sponsors: A sponsor might have little or no previous experience in completing and operating equivalent projects.
- Contractors: The firms hired for engineering, procurement and construction may fail to meet deadlines or budget constraints.
- Ship construction and/or operation: The firms involved in building ships and/or ocean

transport may not operate efficiently or on schedule.

- Use of new technologies: Unproven technologies for drilling, construction or operations can cause delays or cost overruns.
- Strength of off-take commitments: Sales contracts that are short-term or allow buyers too much leeway to terminate or alter the agreements could lead to unsold inventory.
- Creditworthiness of purchasers: Despite strong off-take commitments, buyers could become insolvent and unable to make good on contracts.

The stability of a country and its government, environmental concerns, currency fluctuations and market shifts can also alter the initial estimates of a project's cost and return on investment.

Given the large risks and high costs of LNG projects, partnerships are the status quo. Outside of facilities owned by the national oil companies of Algeria and Libya — which, in the 1960s, became the first and second countries, respectively, to export LNG — no other large-scale LNG export operation in the world is singly owned.

## QATARGAS 2 (QATAR)

Qatargas 2 began operating in 2009 and was the world's first fully integrated value-chain LNG venture. The same partners developed and funded the entire chain from 30 wellheads and three unmanned platforms in Qatar's offshore North Field, to liquefaction, storage and export facilities at Ras Laffan, to a fleet of the 14 largest LNG ships ever built and, finally, to the largest LNG receiving terminal in Europe.

*Source: Qatargas*

**Mozah, one of the world's largest LNG tankers, delivers a Qatargas 2 cargo at the South Hook LNG Terminal in Milford Haven, U.K., May 7, 2009.**

| Qatargas 2 | |
|---|---|
| **Location:** | Qatar |
| **Cost:** | More than $12 billion (includes entire LNG chain from wellhead to liquefaction plant, tankers and receiving terminal) |
| **Service start:** | 2009 |
| **Capacity:** | 2 bcf a day |
| **Owners:** | Qatar Petroleum, ExxonMobil, Total |
| **Financing:** | 70% debt, 30% equity for LNG plant |

Financing the more than $12 billion project was a challenge based on the risks perceived by would-be lenders. The project was expensive — at the time it was the world's largest-ever energy project financing — and it would be the first project to base its delivered LNG on hub prices in its target market, the U.K., rather than on Btu-equivalent oil prices. It also was entering unexplored technological territory with its mega-production trains and enormous ships.

The facility's two liquefaction trains (the compressors, coolers and other industrial equipment to supercool the gas) each have an output capacity averaging 1 billion cubic feet of natural gas as LNG a day — almost twice the capacity of most other liquefaction trains worldwide.

Supporting the trains are a series of storage and export facilities for byproducts, including condensate production (90,000 barrels per day) and liquefied petroleum gas (27,000 barrels a day).

Each Q-Max ship can transport almost 6 bcf of natural gas as LNG. Most ships under construction will carry about 3.5 bcf.

The main destination for the LNG was originally Qatargas's South Hook terminal at the deep-water port of Milford Haven in the U.K., which uses more natural gas than any other European country. The shipping destination for much of the gas changed, however, after the 2011 meltdown at Japan's Fukushima Daichi nuclear plant. With Japan's electrical utilities turning to LNG instead of nuclear power, Qatar's natural gas has increasingly ended up at ports in Japan, with cargoes also going to other Asian customers to meet rising demand.

The high credit rating and strong position in the U.K. gas market of a wholly owned ExxonMobil subsidiary, a minority partner in the Qatargas 2 project, helped make it possible to package up the whole chain of development. The subsidiary signed a 25-year gas sales and purchase agreement for 100 percent of the volume of one train, or half the project's total capacity.

The upstream and liquefaction portions were financed with 30 percent equity and 70 percent debt. Equity in the first train is held by ExxonMobil (30 percent) and Qatar Petroleum (70 percent). The second train has Qatar Petroleum with a 65 percent stake, ExxonMobil with an 18.3 percent stake and France's Total at 16.7 percent.

On the debt side of the upstream and liquefaction operations, 36 commercial banks provided 15-year loans totaling $3.6 billion. In addition, six Islamic banks provided a total of $530 million for a term of 15 years. ExxonMobil provided $1.9 billion in loans.

Two government-operated export credit agencies provided loans with terms of 16.5 years. The U.S. Export-Import Bank provided $405 million and Italy's Istituto per i Servizi Assicurativi del Credito all'Esportazione provided $400 million.

Export credit agencies are often pulled in to cut political risk, but not in the case of Qatargas 2. In fact, the credit rating of state sponsor Qatar was high and it was a stable country with a proven track record in developing and operating LNG projects. Rather, the export assistance was simply seen as another source of debt capacity.

Britain's South Hook receiving terminal was financed with 85 percent debt and 15 percent equity. Twelve commercial banks loaned $632 million and ExxonMobil loaned $270 million (expressed in U.S. dollars at the March 2013 exchange rate).

## NLNGPLUS (NIGERIA)

Shareholders shouldered the financing burden of the $5.4 billion cost to build the first three trains at Nigeria's Bonny Island a decade ago, but when the time came for trains four and five, outside investors were invited to take a turn.

Dubbed NLNGPlus, the expansion project off the West African coast set off a series of firsts for the country and the region. NLNGPlus was, at the time, Nigeria's largest project financing and sub-Saharan Africa's largest private-sector financed project. Project Finance magazine called it the "African oil and gas deal of the year" for 2002.

The $2.2 billion expansion sponsored by Nigeria LNG, a joint venture of Nigerian National Petroleum Corp. (49 percent), Shell (25.6 percent), Total LNG Nigeria Ltd. (15 percent) and Eni's Nigerian Agip Oil Co. (10.4 percent), was ultimately financed with about 48 percent debt and 52 percent equity.

| NLNGPlus | |
|---|---|
| **Location:** | Nigeria |
| **Cost:** | $2.2 billion (expansion of existing LNG facility) |
| **Service start:** | 2005-2006 |
| **Capacity:** | 1 bcf a day |
| **Owners:** | Nigerian National Petroleum, Shell, Total, Eni |
| **Financing:** | 48% debt, 52% equity |

Each of the expansion's two trains has an average daily capacity of about 530 million cubic feet a day. Shell was a key purchaser of the plant expansion's output. Markets for NLNGPlus include Italy and Spain.


*Source: Shell*

**Workers outside LNG storage tanks at Bonny Island, Nigeria, Feb. 28, 2011.**

The $1.06 billion in loans for the expansion was covered by four export credit agencies, 19 international commercial banks, a Nigerian commercial bank, and one public international institution, the African Development Bank.

The U.S. Export-Import Bank, the U.K.'s Export Credit Guarantee Department, Italy's Istituto per i Servizi Assicurativi del Credito all'Esportazione, and private credit insurer Gerling NCM (now Atradius) of the Netherlands provided loan guarantees totaling $620 million over eight years to the 19 international banks. The four agencies promised, in the event a default, to purchase the debt from those banks and take on responsibility for collecting the loan.

The $135 million guarantee from the U.S. Export-Import Bank was its largest-ever private-sector financing in Nigeria. Benefits to U.S. companies included equipment sales and a contract for Kellogg Brown & Root, an international engineering and construction company based in Houston. Citibank N.A. of London was the guaranteed lender. The loan came as the United States was moving to diversify its global oil and gas supply sources.

Additional debt financing not covered by loan guarantees came from the international banks ($180 million) and six Nigerian commercial banks ($160 million). The African Development Bank loaned $100 million for eight years.

Lenders were attracted, among other things, by the previous performance of Nigeria LNG's Bonny Island operations, which started in 1999, the use of proven technology and existing facilities, and the seniority of their debt over previous loans provided by shareholders, meaning they would be repaid before shareholders if the project encountered financial difficulties.

Train 4 came on stream in November 2005 and Train 5 followed in February 2006. Sponsors fully repaid the lenders by December 2010.

| Sabine Pass | |
|---|---|
| **Location:** | Louisiana |
| **Cost:** | $6 billion (adding liquefaction capability to existing import terminal) |
| **Service start:** | Under construction; first gas late 2015 |
| **Capacity:** | 1.2 bcf a day from the first two trains |
| **Owners:** | Cheniere Energy Partners |
| **Financing:** | 65% debt, 35% equity |

## SABINE PASS (U.S.)

The first LNG export facility in the Lower 48 states and the first facility in the world that can both export and import LNG is taking shape on Louisiana's Gulf Coast.

Houston-based Cheniere Energy Partners, L.P., has secured financing for the first two of possibly six trains at the Sabine Pass LNG terminal in Cameron Parish, La. The terminal opened in 2008 to unload and regasify foreign LNG, but shale gas finds in the United States severely deflated the import market and the company's balance sheet.

Cheniere hopes to turn its fortunes by taking advantage of the boom in domestic natural gas supplies and its nearness to pipelines from several of the country's largest shale gas plays. Rather than enter the LNG export business itself, Cheniere is establishing itself as a reliable liquefaction plant operator for foreign buyers, marketers and brokers that are betting U.S. LNG sales abroad will prove profitable over the long term.

To save on construction costs, a Cheniere subsidiary, Sabine Pass Liquefaction, LLC, is adding liquefaction capacity to the site that houses the existing receiving terminal, LNG storage tanks and regasification equipment.

The company estimates the total cost of liquefaction trains 1 and 2 to hit about $6 billion. Each will have an output capacity averaging almost 600 million cubic feet per day as LNG.

*Source: Cheniere Energy Partners*

**Artistic rendering of the planned Sabine Pass LNG export facility. The LNG production trains are in the foreground, with the storage tanks in the middle of the site.**

Cheniere Energy Partners secured $2 billion in project equity for its leading pair of trains from two sources. Parent company Cheniere Energy Inc., agreed in early 2012 to purchase $500 million worth of newly issued shares in the LNG export subsidiary, a deal it financed by selling equity in itself to Singapore state investment firm Temasek Holdings and Asia-based private-equity firm RRJ Capital.

The rest of the equity arrived later in 2012 with an agreement in which investors affiliated with private -equity manager Blackstone Group LP, including China Investment Corp., a state-owned investment fund, purchased $1.5 billion worth of shares in Cheniere Energy Partners.

Blackstone will be compensated not in cash, but in more stock, which eventually will convert to an ownership stake and seats on the 11-member board of Cheniere Energy Partners. Blackstone will also hold three of the five seats on the board's executive committee, whose approval will be necessary for major company decisions.

After cementing the equity deals, Cheniere inked loan agreements now totaling $2.3 billion from a group of 21 private and quasi-private lenders based in Asia, Canada, the United States and Europe, including the project's financial adviser, France-based Société Générale. The term is seven years at an interest rate that fluctuates based on the rates leading banks in London charge each other to borrow.

In addition to the $2 billion in equity and $2.3 billion in loans, Cheniere also sold $1.5 billion in bonds backed by future revenues from the export terminal. And it plans to use $255 million in cash flow from its first production train to help pay for construction of the second train — a timing maneuver that worried Standard & Poor's a bit in its rating of the project's debt.

Sabine Pass boosted its attraction to lenders by becoming the first company to receive authorization from the Department of Energy to export LNG to countries that do not have free-trade agreements with the United States. The approval process slowed down after Cheniere. As of March 2013, the department had 19 such applications pending while it considers a consultant's export economics report, more than 200,000 public comments, and several criteria as part of its public-interest review.

Lenders also liked that Cheniere had 20-year sales agreements in place with the U.K.'s BG Group and Spain's largest utility Gas Natural Fenosa for nearly the entire capacity of the first two trains.

The contracts, dubbed "take-or-pay," require the liquefaction customers to pay for the plant's capacity whether they use it or not, guaranteeing a revenue stream for Cheniere even if gas prices are high and the two customers don't buy any U.S. gas for liquefaction and export.

Construction began last year and Cheniere expects train 1 to come online by late 2015, with train 2 starting six to nine months later.

Cheniere hopes to wrap up a separate financing process for two more trains this year. Trains 3 and 4 already have customers under contract. Korea Gas Corp. and India's largest gas utility, GAIL India, have entered into 20-year take-or-pay contracts. The four trains will be capable of turning an average of more than 2 bcf a day of gas into LNG. The company recently filed initial applications with the Energy Department and Federal Energy Regulatory Commission to add trains 5 and 6. Total Gas & Power North America Inc. has entered into a 20-year take-or-pay deal for output from train 5, as has U.K.-based Centrica PLC, pending regulatory approval and project sanction by Cheniere.

| PNG LNG | |
|---|---|
| **Location:** | Papua New Guinea |
| **Cost:** | $19 billion (includes upstream development costs and 435-mile pipeline to LNG plant) |
| **Service start:** | Under construction; first gas 2014 |
| **Capacity:** | 900 million cubic feet a day |
| **Owners:** | ExxonMobil, Oil Search, Santos, Japan Papua New Guinea Petroleum, Nippon Oil Exploration, and Papua New Guinea companies Mineral Resources Development, Petromin PNG Holdings and The Independent Public Business Corp. of Papua New Guinea |
| **Financing:** | 70% debt, 30% equity |

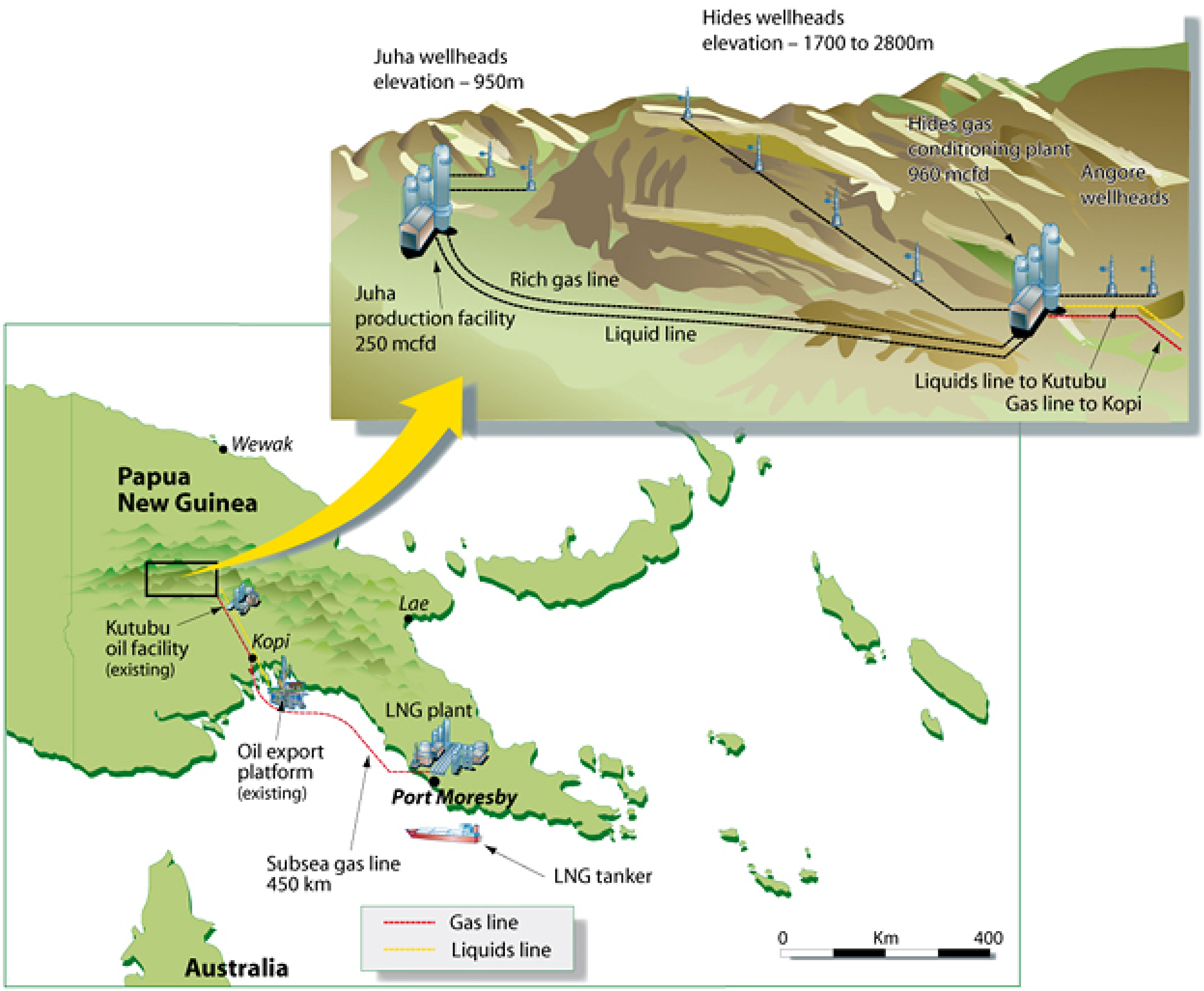
## PNG LNG (PAPUA NEW GUINEA)

After operations begin in 2014, Papua New Guinea's first gas export project will have the capacity to ship an average of 900 million cubic feet per day to contracted buyers in Japan, China and Taiwan.

At $14 billion in debt financing for the $19 billion project, PNG LNG is one of the largest-ever project finance transactions. The ExxonMobil-led endeavor is aiming for 30 percent equity and 70 percent debt.

Financing covers new upstream facilities in the Southern Highlands; a 435-mile pipeline through thick jungle and across the seafloor of the Gulf of Papua; and a liquefaction plant and export terminal at Caution Bay, northwest of Port Moresby.

In developing energy resources, multinational firms and national oil and gas companies often team up as a partnership, joint venture or other structure. Having creditworthy private-sector partners allows national companies, should they happen to be less creditworthy, to participate in project financing at better terms than they could get on their own, while private-sector players can benefit in myriad ways from government support of a project.




*Source: Esso Highlands*

**Natural gas from the remote Southern Highlands of Papua New Guinea will be carried 435 miles by pipeline to a liquefaction plant and export facility of Port Moresby.**

PNG LNG followed this financing structure to attract lenders. Aside from ExxonMobil, no other shareholder had an AAA credit rating. The other shareholders were either lower-medium grade, below investment grade or unrated.

Lenders saw additional risk in Papua New Guinea itself. The country does not have a reputation for being a particularly stable place for foreign investment, a fact openly acknowledged by its president, Peter O'Neill, during a talk in November at the National Press Club in the Australian capital of Canberra. Corruption is common and many residents are skeptical that the PNG LNG project will bring them any benefits.

Commercial banks, still smarting from the financial crisis, were unwilling to shoulder the risks without some additional cushioning. Public export credit agencies then stepped in. These institutions have greater capacity for high-risk environments because they are backed by governments and have the added incentive of advancing domestic interests.

The U.S. Export-Import Bank alone provided $3 billion in loans and guarantees, making it the project's largest non-sponsor funding source. At the time this was largest foreign financing in the bank's nearly 80-year history. ExxonMobil predicted the U.S. government-sourced debt financing to PNG LNG would enable "significant U.S. goods and services procurement" involving "70 major U.S.

suppliers supported by hundreds of small businesses."

(The Ex-Im Bank broke its record in September 2012 with a $4.975 billion direct loan to a joint venture between Dow Chemical Co. and Saudi Arabian Oil Co. for a petrochemical complex in Saudi Arabia.)

The participation of six export credit agencies from five countries (the United States, Japan, Australia, Italy and China) succeeded in attracting more bank lending. The agencies' assistance totals $8.3 billion in loans and guarantees to back commercial bank loans, while 17 commercial banks are chipping in $1.95 billion not backed by government guarantees. ExxonMobil is lending $3.75 billion.

Equity sponsors are affiliates of ExxonMobil (33.2 percent), Australian-based firms Oil Search Ltd. (29 percent) and Santos Ltd. (13.5 percent), Japan Papua New Guinea Petroleum Co. and Nippon Oil Exploration Ltd. (combined 4.7 percent). The three state-controlled Papua New Guinea firms (totaling19.6 percent) are Mineral Resources Development Co. Ltd., Petromin PNG Holdings Ltd. and The Independent Public Business Corp. of Papua New Guinea.

Four LNG customers in East Asia have committed to buying most of the gas in long-term take-or-pay contracts. They are China Petroleum and Chemical Corp. (Sinopec) at almost 100 billion cubic feet per year, Osaka Gas Co. Ltd. at almost 75 bcf per year, Tokyo Electric Power Co. Inc. at almost 90 bcf per year and Taiwan's Chinese Petroleum Corp. at almost 60 bcf per year.

## GORGON (AUSTRALIA)

Not all LNG export projects are built using the debt and equity structure of project finance. The financial lifelines of Australia's Gorgon development, currently the largest and costliest LNG project under construction in the world, run straight to the balance sheets of its corporate sponsors.

The behemoth of a project off the coast of Western Australia is a case of internal financing. The sponsors are digging into their profits and paying for the project directly through capital expenditures or borrowing money on their own.

| Gorgon | |
|---|---|
| **Location:** | Australia |
| **Cost:** | $52 billion (includes gas field development costs) |
| **Service start:** | Under construction; first gas 2015 |
| **Capacity:** | 2 bcf a day |
| **Owners:** | Chevron, Shell, ExxonMobil, Osaka Gas, Tokyo Gas, Chubu Electric Power |
| **Financing:** | Each partner used its own assets to finance its share of construction costs. |

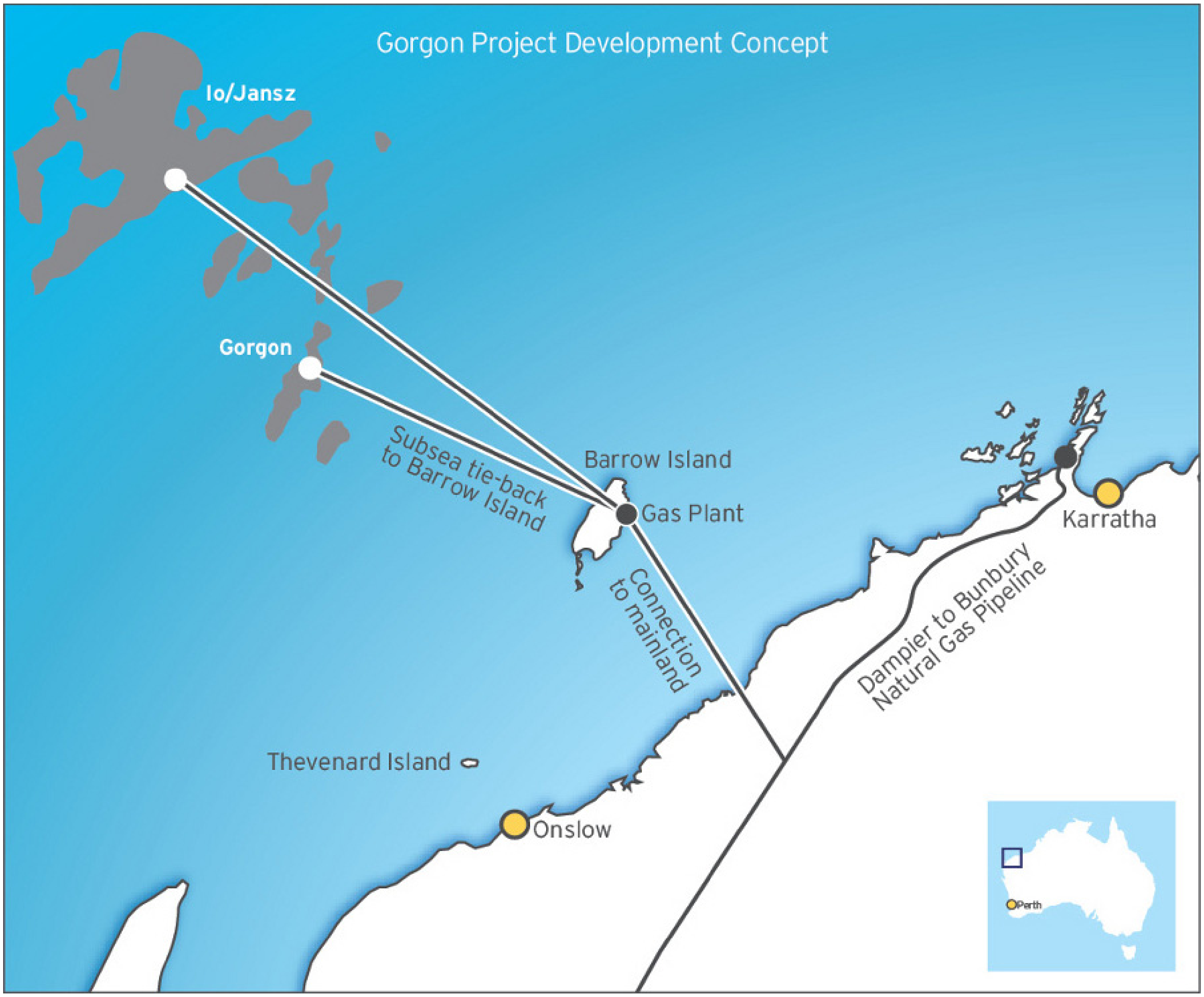
The main sponsors of the $52 billion Gorgon project are all deep-pocketed supermajors. Project operator Chevron holds a 47.3 percent equity stake in Gorgon, with subsidiaries of ExxonMobil and Royal Dutch Shell holding 25 percent each. Three Japanese utility companies own the remaining equity.

The project is just one of many each of the three main sponsors are developing around the world.

The total cost estimate includes upstream development of the remote gas fields, the farthest located 125 miles offshore. The LNG plant is on an island between the gas fields and the coast.

The development includes a subsea upstream operation, flow lines from the ocean floor to a three-train LNG facility on Barrow Island, a carbon sequestration project and a domestic gas pipeline feeding Gorgon gas into the Dampier-to-Bunbury natural gas pipeline on the Australian mainland. Chevron recently reported that the project is about 60 percent complete.

ExxonMobil projects its capital expenditures at about $37 billion per year through 2016, with the funds spent on Gorgon and other major projects




Source: Chevron

**At $52 billion, the Gorgon LNG project, off the coast of Western Australia, is the largest single investment ever undertaken in Australia.**

worldwide. Shell plans to spend approximately $33 billion in capital on various projects in 2013, much of it in Australia and North America. About $9 billion of Chevron's $36.7 billion capital and exploratory investment program for 2013 will go to Gorgon and Wheatstone, another LNG project under construction in Australia.

As Gorgon project costs have grown, so have the capital expenditures of all three companies. Last year Chevron revised its outlook on Gorgon's cost to $52 billion, up from a previous estimate of $43 billion. The company said about one-third of the cost increase came about as a result of a strengthening Australian dollar.

Other reasons cited by the company included higher labor costs, lower-than-expected labor productivity, the challenge of transporting materials to a remote location and weather delays.

Gorgon's sponsors paved the way for internal financing through solid, long-term supply contracts.

Chevron has long-term sales and purchase agreements with three Japanese utilities, each of which have small equity shares in the project; two Japan-based customers that are not shareholders; and GS Caltex, a South Korean company owned partially (50 percent) by Chevron.

Chevron also has binding long-term agreements for delivery of about 65 million cubic feet per day of natural gas to Western Australian consumers starting in 2015.

Fellow sponsor ExxonMobil will be selling almost 75 bcf of gas a year to Petronet LNG of India in a deal worth nearly $26 billion over 20 years. Exxon is selling the remainder of its LNG to PetroChina, almost 110 bcf a year, over 20 years at a reported total cost of $41 billion.

Shell has a contract to sell about 48 bcf a year to PetroChina and has signed a memorandum of understanding with India's Gujarat State Petroleum Corp. for the potential sale of 24 bcf a year.

The Gorgon LNG project is the largest single investment ever undertaken in Australia. The gas fields in the Greater Gorgon area hold more than 40 trillion cubic feet of natural gas and form Australia's largest known gas resource.

Average daily capacity is expected to reach 2 billion cubic feet of natural gas and 20,000 barrels of condensate. The first LNG cargo is expected in 2015.

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

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