THE Lithuanian government may take full ownership of its Independence floating LNG terminal, as Vilnius looks for ways to solidify its supply security.

The Baltic state’s Prime Minister Algirdas Butkevicius said last week his government would decide in the autumn what to do about its LNG import vessel, which is operating at the Port of Klaipeda under lease until 2025. Government plans could include a buy-out once the lease agreement is over if the resolution is approved, Butkevicius said.

“In the autumn [we] will take a final decision on the LNG ship buy-out, but we need to get ready now,” Butkevicius said in a statement following a meeting of the project commission last week.

Norwegian developer Höegh LNG built and delivered the Independence vessel last year, with gas delivered under long-term contract by Statoil and a preliminary deal signed with potential American exporter Cheniere Energy for cargoes to arrive from 2016.

Brought onstream last December, the 4 billion cubic metre per year facility provides the first source of non-Russian gas for the Baltic region. Gazprom statistics show the Russian monopoly supplied 4.5 bcm to the Baltics in 2013, with Lithuania taking 2.7 bcm, Latvia 1.1 bcm and Estonia 0.7 bcm. This constituted the entire supply for the countries.

Deals have already been signed for onward delivery of small volumes to Latvia and Estonia from Klaipeda, but infrastructure costs need to be reduced as a result of declining gas consumption across the region, Butkevicius said.

“All of the LNG terminal costs are included in the additional component [a so-called security of supply tariff] of natural gas prices. Taking a consistent decline in natural gas consumption not only in Lithuania, but also in the Baltic countries, we see that the infrastructure cost is likely to grow, so now we are discussing how to reduce that burden,” Butkevicius said.

Good neighbours?

Lithuanian consumers pay an extra tariff in their energy bills that goes towards the costs of the FSRU and the added premium of diversified supply. One of the problems in securing finance for the terminal is establishing who benefits. With Estonia and Finland pursuing their own fixed-terminal option, it remains unclear whether Vilnius’s neighbours will contribute to the costs of operating the Klaipeda vessel.
“It’s now being used in negotiations not only by Lithuanians but also Estonians, reportedly,” Vija Pakalkaite, a Baltic gas market researcher at the Central European University in Budapest, told Interfax.

“There were fears back in 2005 and later that, as soon as a Baltic state builds a terminal, Gazprom may start predatory pricing of its gas, meaning selling gas for a little bit cheaper than [that which is] accessible via LNG.”

According to Pakalkaite, Gazprom’s predicted response bolstered the rationale for a floating terminal, which was cheaper to build than a permanent onshore facility and allows flexibility in the event that it is no longer required.

Gazprom supplied a discount to Lithuanian importer Lietuvo Dujos last May, described at the time as “significant” by the importer as its long-term contract neared expiry. This has also apparently helped importers in Riga and Tallinn. “So Estonians or Latvians are now more secure and can use the Lithuanian LNG terminal as leverage in negotiations without paying a penny for it,” Pakalkaite said.

On a visit to the Klaipeda site last week, Kristen Michal, Estonia’s minister of economy and infrastructure, said it was “clear that the LNG terminal can contribute to the security of gas supply in the whole Baltic region”.

Current terminal operator Klaipedos Nafta is planning on taking out a €300 million ($328 million) loan in the autumn, according to the government, which reported the deal while announcing plans to buy the vessel. Future state ownership, albeit a decade from now, would potentially save €70 million over 30 years, the government claims.

Meanwhile, Butkevicius said on national radio on Thursday that the state could intervene if a buyer from the east attempts to take control of the country’s biggest fertiliser company and single largest gas consumer, Achema Grupe. The firm said it would reduce production last summer because of high gas import prices from Gazprom and is highly reliant on the gas price.

“The government really could have an effect if shares in Achema were to be sold to a company from the east. Clearance is needed to purchase those shares, because a law was passed recently that requires monitoring, supervision and permits in the event of investment in strategic Lithuanian enterprises,” he said on radio station Ziniu Radijas.

Any owner of Achema would also take part-control of the Klaipeda port through its subsidiaries. Minority shareholders in the company are reportedly positioned to sell, making politically sensitive investment from Russia a possibility. Butkevicius said Achema was planning to work on securing its own gas deliveries via the Klaipeda LNG terminal.

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Europe

The UK government may take the responsibility for decisions on fracking away from local authorities with new rules planned to fast track applications for the process, British media reported over the weekend. Energy Secretary Amber Rudd was criticised by anti-fracking campaigners after she requested local councils speed up the decision process. The government is eager to push ahead with fracking to help the UK meet its power demand. “Over 80% of our homes are dependent on gas for cooking and heating, and a substantial amount of electricity is produced by gas... but, without indigenous production, over 75% of our gas will come from outside the UK in the next decade,” a spokesman for industry body UK Onshore Oil and Gas told reporters. UK shale company Cuadrilla’s application to drill in Lancashire was rejected in June by the local council, which had taken a year to make the decision. North Yorkshire County Council is considering an application for test fracking by Third Energy.

Gazprom has reconsidered the configuration of its proposed Turkish Stream pipeline, potentially reducing it from the four lines originally planned to just one or two lines. The pipeline will run under the Black Sea from Russia to the Turkish coast. Russian officials have sent two versions of the intergovernmental agreement for Turkish Stream to Ankara, an Energy Ministry spokesman told Interfax. “There is a proposal for one line and one for four.

There has been no response yet,” the spokesman said. 

FSU

Gazprom has reported a 71% increase in its Q1 net profits, to RUB 382.1 billion ($5.94 billion) compared with RUB 223 billion for the same period in 2014, the company reported on Monday. “Despite the challenging business environment the company’s total sales net of VAT, excise tax and customs duties increased by RUB 89.5 billion, or 6%, to RUB 164.8 billion for the three months ended March 31, 2015 compared with the same period of the prior year,” the company said. Gazprom’s outlook for European exports is positive for the second half of the year. Last month set a new record for the company’s exports to Europe and Turkey, which reached 14.3 billion cubic metres – a rise of 23% year on year. Last week, Gazprom raised its estimate for gas exports to non-CIS countries in 2015 by another 5 bcm. Deputy Chief Executive Alexander Medvedev made the last estimate of 153-155 bcm at the start of June.

Kazmunai gas has sold its 10% plus one share in the Kashagan project to the National Bank of Kazakhstan, said Berik Beisengaliyev, a business development director and a member of the management board at sovereign wealth fund Samruk-Kazyna. “We are attracting about $4.7 billion and will acquire a 50% holding in the Kashagan project. The deal is expected

The Week Ahead

Monday 10 August
■ Results of prequalification tender for oil and gas exploration in Uganda

Tuesday 11 August
■ Japan’s Sendai nuclear power plant scheduled to be restarted by Kyushu Electric Power
■ CEZ Group H1 results
■ Registration deadline to take part in Brazil’s 13th oil licensing round

Wednesday 12 August
■ E.On H1 results

Thursday 13 August
■ RWE H1 results
■ WesternZagros H1 results

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to close by the end of 2015,” Beisengaliyev said. Oil production at Kashagan began in 2013, but a few months later a gas pipeline leak was detected and oil production was suspended. It has not resumed, and according to an inspection report the gas and oil pipelines need to be replaced. Kashagan may start producing oil in late 2016 or early 2017, according to a recent statement by Karim Massimov, Kazakhstan’s prime minister.

The cost of construction for Gazprom’s proposed pipeline in Eastern Siberia differs substantially from project costs in Europe or Western Siberia, Interfax has learned. Based on the latest tender, the estimated cost to build each kilometre of pipeline is RUB 177 million ($1.82 million) – more than twice the cost of building a kilometre of pipeline in Europe, where conditions differ substantially from those in Yakutia. Based on the results of the last four tenders, the Southern Corridor pipeline will cost RUB 76 million per km. Gazprom called its first public tender to build a section of the Power of Siberia pipeline in 2014, after signing a supply contract with China National Petroleum Corp. A 93.4 km section from Lensk to the Saldykselkaya 1 pumping station (301.1 km along the route) had a price of RUB 16.58 billion (including VAT), Gazprom recently reported. The contract to build the first section of Power of Siberia, from Chayanda to Lensk, was earlier awarded to Stroytransgaz (STG) without a tender. Gazprom officials have refused to disclose the cost of the STG contract, but based on recent benchmark costs STG’s contract to build 207.7 km of the pipeline may have cost RUB 37 billion.

Middle East
Lisco, Libya’s biggest steelmaker, has stopped production because of power shortages, according to a Reuters report citing the firm’s chairman. Fighting between rival factions in Libya has damaged power plants and transmission infrastructure, causing outages. Lisco’s Misrata-based plant will be out of operation for at least a month, the report said.

Asia Pacific
Gas reserves in the West Philippine Sea (WPS or South China Sea) are sufficient to power the Philippines’ grid for at least 20 years, the Liquefied Petroleum Gas Marketers’ Association (LPGMA) told The Manila Times over the weekend. “This is one of the compelling reasons why we have to secure our [323 km] exclusive economic zone and its contiguous area, including the seabed of the continental shelf up to [565 km] from the national coastal baseline. We have to defend the zone against China and other foreign threats,” LPGMA Representative Arnel Ty told journalists. Ty referred to the Sampaguita field, which is estimated to hold 130 billion cubic metres of gas and is 148 km off the country’s western coast.

China
Construction has started on a gas-fired distributed generation project in Nanchong city’s Jialing industrial region in Sichuan province, local media reported on Friday. With 40 MW of installed capacity, the RMB 352 million ($56.67 million) project is a joint investment between Beijing ZNXY Energy & Environment Technology and Sichuan Green Energy Technology. It is expected to produce 320 GWh of electricity and 960,000 tons of steam every year.

Guanghui Energy’s subsidiary Xinjiang Fuyun Guanghui New Energy has signed a sales and purchase framework agreement with Sinopec Natural Gas on the transmission of synthetic natural gas (SNG) from a coal-to-gas (CTG) project in Xinjiang province. Fuyun will build a 4 billion cubic metre per year CTG project in Xinjiang’s Zhundong coal field, while Sinopec Natural Gas will purchase and transmit the SNG.

North America
Houston-based oil services provider Baker Hughes has reported an increase in the number of operational oil and gas drilling rigs for the third week running. For the week ending 7 August, the number of rigs in use increased by 10, to 884. There were 670 oil rigs in use and 213 gas rigs, up by four from last week. However, this is still lower than during the same period in 2014, when 1,098 oil and gas rigs were in use. Historically, the highest United States rig count was 4,530 in 1981, while its lowest was 488 in 1999. Baker Hughes may merge with its competitor Halliburton. Halliburton said the European Commission has asked for more information on the planned $35 billion merger. If the deal is successful, the companies are forecast to save a combined $2 billion in annual costs. The US Department of Justice has also sought additional information on the merger.
German reforms throw gas a lifeline

The German government wants to promote a gradual switch from coal to gas in power generation, despite leaving out capacity markets in its latest reform proposal. EU Policy & Regulation Editor Andreas Walstad reports from Brussels.

The proposed German power market reform has thrown a lifeline to operators of gas-fired power plants, which could now play a key role in decarbonising the country's economy.

Among the reforms proposed in July's white paper is the creation of a capacity reserve, whereby older and inefficient coal-fired power plants are only allowed to run during peak hours. Experts say this will likely benefit gas-fired generators, which have been struggling to make profits over the past few years.

"In a long-term perspective, Germany wants to change its energy mix so that 80% comes from renewable energy. So far, we have reached almost 30%. In the meantime, to have an additional positive effect on carbon dioxide emissions, the government wants to promote the replacement of coal-fired power plants with gas-fired plants," Guido Hermeier, a Düsseldorf-based senior credit analyst with Bayerische Landesbank, told Interfax.

The white paper dispensed with an earlier proposal to impose environmental charges on coal-fired power plants. Instead, the capacity reserve will remunerate operators for keeping lignite plants on standby. The costs will be passed on to the end-users.

"We will align the CHP regulation and promote the replacement of coal with gas."

SIGMAR GABRIEL
German economy and energy minister

"The original idea was to impose a climate levy on coal-fired plants to make them unprofitable. Instead, seven or eight very old plants will be put into a capacity reserve," said Hermeier.

Despite the reforms, gas-fired generation seems unlikely to gain market share in the short term as long as coal is more profitable to burn. The clean dark spread in Germany – the profit from generating electricity minus the cost of coal and carbon allowances – has been positive over the last few years.

However, the consensus among analysts appears to be that the proposed German reforms, coupled with the 2030 climate targets agreed by EU leaders in October last year, will benefit gas over coal in the longer term.

The question is when it will happen, as many details of the reforms to Germany's electricity sector are still missing. Exactly how the capacity reserve for coal-fired plants will work in practice and which plants will be affected, for instance, has not yet been decided.

"The details of the capacity reserve are still under discussion. We expect more details from the government probably this autumn," said Hermeier.

Swedish-owned utility Vattenfall said in its half-year earnings results that the capacity reserve proposed in the white paper would clarify the conditions for its lignite power plants in Germany, which it wants to sell. But, in its H1 report, German utility ENBW called for "stronger incentives" to switch from coal to gas in power generation.

Coal dominates power
Coal dominated Germany's energy mix in 2014, with approximately 44% of the country's electricity production based on either the hard or brown varieties of the fuel. Gas-fired power generation accounted for 9.6% of the total, according to data from the AGEB.

A combination of 'cheap' prices for coal and carbon allowances, as well as relatively low electricity prices because of the expansion in renewables, has rendered gas-fired power production in Germany unprofitable, as it is in many other EU countries.

The white paper also opens up more funding for gas-fired combined-heat-and-power (CHP) plants. The annual CHP funding cap is set to be raised from the current level of €750 million ($816 million) to €1.5 billion. A total of €500 million of the annual funding has been earmarked to replace existing coal with gas in CHP generation and to fund new gas-fired CHP plants.

"We will align the CHP regulation and promote the replacement of coal with gas," Sigmar Gabriel, Germany's economy and energy minister, said in July.

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EnergyHub profile: Greece

Greece’s potential as a gas hub is looking promising, with a number of high-profile infrastructure projects linked to the country. EU Policy & Regulation Editor Andreas Walstad reports from Brussels.

GREECE has only modest oil and gas reserves, and lignite is the most important indigenous energy resource. Gazprom is the main supplier of gas to DEPA, Greece’s biggest gas utility. DEPA also imports smaller volumes of gas from Turkey’s Botas, as well as LNG from Algeria’s Sonatrach. In total, the company imports around 4.2 billion cubic metres per year of gas, most of which is used for power generation.

DEPA sells gas under medium- and long-term take-or-pay contracts to power producers, large industrial customers and the three existing gas distribution and supply companies. The company is 65%-owned by the Hellenic Republic Assets Development Fund and 35% by Hellenic Petroleum. Through its wholly owned subsidiary DESFA, it owns and operates the regulated high-pressure gas transmission network and Greece’s only LNG terminal.

The country has two FSRUs in the planning stages, both in the Aegean Sea. DEPA is the promoter of the Kavala project, while Gastrade plans to build the Alexandroupolis project.

Both have been selected by the European Commission as Projects of Common Interest (PCIs) and are expected to start up by 2017. However, it is uncertain how the economic situation in Greece will affect the projects.

Other PCIs connected to Greece include the IGB interconnector to Bulgaria, the Trans-Adriatic Pipeline, the Interconnector Turkey-Greece-Italy and a pipeline from offshore Cyprus to the Greek mainland via Crete. A proposed gas pipeline between Greece, Bulgaria and Romania also has support from Brussels.

Greece has the potential to become a gas hub and its strategic importance was further highlighted by Gazprom’s announcement of the Turkish Stream pipeline.

Gazprom plans to deliver Russian gas to the Greek-Turkish border and let EU customers build the necessary infrastructure to transport the gas from there. It remains highly uncertain whether this project will come to fruition, however.

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Revithoussa LNG terminal

| Start date | 2000 |
| Location | Revithoussa Island, Gulf of Megara |
| Regas capacity | 5 bcm/y |
| Unloading jetties | 1 |
| Storage capacity | 130 Mcm |
| Operator | DESFA |
| Notes | The terminal is currently being expanded, which will see its regasification capacity increase to 7 bcm/y and its storage capacity increase to 225 Mcm by 2016. |

Source: Gas Infrastructure Europe.

LNG imports, exports and project intelligence

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Fitting the pieces of SA’s gas-fired power puzzle

Private power producers are being left to fill the policy void on how to structure South Africa’s nascent gas market. Africa Editor Leigh Elston reports from Maputo.

IN the absence of a clear policy for fixing its power crisis, South Africa is leaning on gas-fired power developers to help better define the problem, as well as provide solutions.

A total of 150 companies submitted responses under the Department of Energy’s (DOE’s) request for information (RFI) for the design of its gas-to-power programme, which closed on 20 July.

The RFI set few limitations on how projects should be structured or how the gas should be sourced or supplied – whether from domestic production or imported via pipeline, LNG, CNG or LPG. LNG terminals and power plants can be offshore, onshore or a combination of both, and the projects can be bundled or unbundled, with participants selecting which elements of the supply chain they would be willing to provide.

The request for proposals for 3.1 GW of new gas-fired generation capacity should be launched before the end of the year, Ompi Aphiwe, deputy director general for energy planning at the Department of Energy (DOE), told journalists in parliament last week.

However, a lack of direction on the government’s long-term gas strategy and on the role gas-fired power will need to play in meeting the country’s energy demands is likely to hinder the tender.

“The RFI wasn’t well presented, and suggests the Independent Power Producer (IPP) unit is more looking for market information to address a policy void than it is able to pre-empt a procurement process,” one consultant, who wished to remain anonymous, told Interfax.

South Africa’s challenges

The difficulty is South Africa has limited gas demand and therefore limited infrastructure to support the import, transport and storage of the fuel.

Building new gas-fired power projects will also require substantial investment across the gas value chain, which will not only be expensive, but also require some support from the government on its future gas strategy and strong regulatory coordination between the DOE and Department of Transport.

None of this has been forthcoming.

“The procurement process is unfortunately being developed in an uncertain gas policy environment – unlike the renewables IPP programme,” the consultant said. Several key issues still need to be addressed, he noted, such as vertical integration in the gas chain, how sales to users besides utility Eskom could be structured into bids, and the potential role of state-owned enterprises in the gas value chain.

Ideally, South Africa’s Gas Utilisation Master Plan – which should outline the government’s 30-year scheme for the development South Africa’s gas industry and its desired gas supply portfolio – would have been presented before the launch of the RFI. The document, which was supposed to be published in the first half of 2015, has been in the final stages of approval since the beginning of the year, according to the DOE.

The government will also need to work out how it will deal with the dollarisation of the electricity tariff. Most of South Africa’s power fleet is fuelled by domestically produced coal and paid for in rand. While Eskom will continue to buy power in local currency, the imported gas to fuel the new IPPs will be paid for in dollars.

Managing the dollar-rand swap will be a major risk for developers, particularly as the rand continues to depreciate. It fell to its lowest level against the dollar in more than 13 years last Wednesday, reaching ZAR 12.82.

Despite the lack of clear government direction, gas-fired power – together with renewables – looks increasingly likely to be the method of choice for filling the country’s power gap, even after being squeezed out of the policy-adjusted Integrated Resource Plan for electricity (IRP).

Combined Cycle Gas Turbines were the favoured technology in many scenarios in original 20-year plan. However, in the policy-adjusted document, which incorporated a number of government’s policy objectives – including affordable electricity, decarbonisation, and localisation and regional development – gas was pushed out in favour of other fuels.

The DOE has revised its projections for 2030’s electricity demand down to 345-416 TWh from the 454 TWh expected in the policy-adjusted IRP because of stagnating economic growth – delaying the need to make a decision on sanctioning 9.6 GW of new nuclear capacity until at least the 2020s.

With LNG prices low and domestic shale gas production still a possibility, it looks increasingly likely that, in a carbon-constrained future, gas could edge its way back to replace some, if not all, of this capacity.

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The main gas distributor for Zhejiang in eastern China has cut its offtake from the province’s first LNG import terminal by nearly two-thirds because of high gas prices and soft local demand.

The terminal in the port city of Ningbo, operated by China National Offshore Oil Corp. (CNOOC), is currently supplying 3 million cubic metres per day (MMcm/d) into Zhejiang’s gas grid, down from 8.7 MMcm/d and 7.47 MMcm/d in July and August last year, according to official data.

The decline is the result of reluctance from Zhejiang Natural Gas, the provincial government-owned distributor, to pay gas prices that were changed without its involvement.

In 2013, the Zhejiang Development and Reform Commission (Zhejiang DRC) and CNOOC agreed to a price of RMB 4.07 per cubic metre ($18.69/MMBtu) for gas from the terminal, falling to RMB 3.97/cm in 2014 and RMB 3.87/cm in 2015. CNOOC also agreed to supply 1 billion cubic metres from the terminal in 2013, 2.8 bcm in 2014 and 4.2 bcm this year.

But China’s move to merge citygate prices for old and new users earlier this year ended up reducing the overall citygate price in Zhejiang. This prompted the Zhejiang DRC to renegotiate a discounted price of RMB 2.94/cm for CNOOC’s gas in 2015, 24% cheaper than the previously agreed price, said the Zhejiang DRC source.

Zhejiang Natural Gas was not involved in the discussions between CNOOC and the Zhejiang DRC, however, and is refusing to pay despite the big discount.

“The company thinks the new price is still high and hasn’t paid us since February,” a source at the terminal told Interfax. “They said they could buy other cheaper supplemental sources in case of gas shortages.”

**Cheaper sources**

The prices were far higher than the maximum citygate prices paid for other onshore sources of gas – such as from the West-East Pipeline and Sichuan-Shanghai Pipeline. When China reformed the way it priced gas in July 2013, it set citygate prices of RMB 2.43/cm for existing Zhejiang users and RMB 3.31/cm for new consumers.

CNOOC secured a higher price to reflect the fact the province intended to use the $1 billion terminal sparingly as a peak-shaving facility during periods of high demand, according to a source with the Zhejiang DRC.

“It has been very helpful for meeting soaring demand since it started up, especially in heating seasons,” said the source. The terminal had a capacity utilisation rate of 55.7% in 2014, its first full year of operations.

Zhejiang Natural Gas is not obligated to take gas from the terminal because the agreement between CNOOC and Zhejiang DRC does not include take-or-pay clauses. “They don’t need to source 4.2 bcm from us this year. I think our supply won’t be more than 1 bcm,” said the source.

Weak downstream demand is another reason for Zhejiang Natural Gas’s reduced offtake from the terminal. Power generation is the biggest consumer of gas in Zhejiang, but gas-fired power stations have seen less uptime as a slowing local economy has reduced electricity demand in the province, said Rao Xiaozhu, a consultant at the Guangdong Oil and Gas Association.

Power plants consumed 54% of the 5.55 bcm used by Zhejiang in 2013, with demand from the sector averaging 16 MMcm/d in July and August that year. In H1 2015, the province’s consumption fell by 5.9% from 2014 to 2.99 bcm and power plants used 27.8% of that, at 1.26 bcm.

Zhejiang’s GDP growth accelerated from 8.2% in the first quarter of this year to 8.3% in Q2 – higher than the 7.6% expansion for the whole of 2014.

CNOOC’s imports via the terminal have dropped as a result of the weaker demand. H1 imports slumped by 26% from a year ago to 578,199 tons during H1 2015, according to customs data.

The terminal received 1.77 mt last year, 57% of which came as oil-indexed volumes contracted from Qatar. The average price of LNG arriving at the terminal was $17.96/MMBtu in 2014.

The terminal has played an important role in Zhejiang’s gas supply since it was commissioned in September 2012. It supplied a record 11.55 MMcm/d in the summer of 2013, meeting nearly half of the province’s overall demand of 25.07 MMcm/d. The terminal provided 572 MMcm between November 2013 and March 2014 – making up 27.8% of total demand for the period.

The terminal supplied 960 MMcm to Zhejiang’s gas grid in 2013, accounting for 17.29% of provincial gas use for the year.

The Zhejiang DRC forecast the terminal would provide 2.8 bcm of the 8 bcm consumed by the province in 2014. But the terminal supplied just 1 bcm, while the province’s consumption came in below forecasts at 6.8 bcm, according to the terminal source.

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Long-term US LNG export applications

This is a list of long-term applications received by the United States Department of Energy/Fossil Energy to export domestically produced LNG, as of 20 July. This is not an exhaustive list, as company and project names change, and projects may submit more than one application to increase export volumes.

<table>
<thead>
<tr>
<th>Project</th>
<th>Website</th>
<th>Capacity, mtpa</th>
<th>Forecast startup</th>
<th>US Department of Energy approval</th>
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<td>Cheniere Energy</td>
<td>13.5</td>
<td>2015</td>
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<td>Cheniere Energy</td>
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<td>Cheniere Energy</td>
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<td>Parallax Energy</td>
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<td>2019</td>
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<td>Oregon LNG</td>
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<td>2021</td>
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<td>Magnolia LNG</td>
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