CHAPTER 4

LNG in the Global Context

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Introduction

The 2000s has seen the U.S. play an important role in the global liquefied natural gas (LNG) market. In the first decade, the U.S. was expected to be the main growth market for LNG imports. Forecasts of growing demand for imported LNG in the U.S. were based on expectations that domestic natural gas production would decline, and imports by pipeline from Canada would fall as more of its production was used to meet growing domestic demand. Observers thought that the U.S. could potentially overtake Japan as the world's largest importer in the 2015–2020 time frame.

Natural gas pipeline companies and utilities had built four receiving terminals in the 1970s and early 1980s in response to earlier outlooks for LNG imports (see the Appendix for a flavor of the U.S. gas policy and politics during this era). With gas production growth in the early to mid-1990s, two of the legacy facilities (Cove Point in Maryland and Elba Island in Georgia) were mothballed from the early 1980s until 2001, and Lake Charles in Louisiana had operated well below capacity. The fourth and

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oldest, in Everett, Massachusetts, had been in continuous service to provide peaking fuel for the New England winters.

By the end of the 1990s, stronger economic growth and diminished gas supply—because low oil and gas prices discouraged drilling—began to show up in higher prices and price shocks (see Chap. 1). In the early 2000s, plans to expand three of the existing U.S. terminals and to develop greenfield import terminals were supported by the expected increase in new LNG supply in the Atlantic Basin and the Middle East. The U.S. had become a target market for much of this proposed new liquefaction capacity. By 2005–2006, proposals had been made for around 50 new terminals. Eight were built, including three offshore facilities using ships to store and regasify LNG.

However, the same natural gas price events during the early 2000s that spurred new LNG receiving capacity development also encouraged new drilling, in particular from the major shale plays. By 2008, as new receiving terminal capacity began to be commissioned, gas supply growth had gathered pace. It became clear that the U.S. not only did not need imported LNG but also would soon have surplus natural gas production available for export. By the end of the first decade, the additive effect of higher oil prices and migration of the U.S. domestic industry to liquids-rich plays induced a burst of associated natural gas production. These tranches of prolific supply growth cemented views that the industry needed to position strategically for exports.

The owners of the import terminals that had been built or were under construction were left with stranded assets, which were no longer required for LNG imports. Cheniere Energy was the first to see the opportunity to convert the import terminals into export plants, using existing storage tanks, jetties, and berths and adding liquefaction trains. The owners of all the LNG import terminals—with the exception of those using ships as floating storage and regasification units (FSRUs, which can be redeployed to other markets) and the terminal in Everett, Massachusetts—have converted, or are planning to convert, their facilities to liquefaction plants. Roughly as many proposals have been made for the development of greenfield liquefaction plants as were for new receiving capacity. Some are on sites previously planned for receiving terminals.

The impact of U.S. LNG derives not only from the amount of product supplied into the global market. U.S. LNG developers also are transforming LNG business models. The pricing structures and contractual arrangements being used for U.S. projects differ greatly from those that have been used for projects elsewhere in the world. For many buyers or off-takers, the price of U.S. LNG loaded onto a ship at the liquefaction plant comprises the cost of natural gas supplied to the plant and a liquefaction fee. As a result, the price of LNG is linked to the cost of natural gas delivered to the liquefaction plant (in many cases the Henry Hub price is used) rather than to oil prices. Furthermore, there are no restrictions on destinations to which U.S. LNG can be delivered, giving buyers and off-takers greater flexibility to manage demand uncertainty than they would have got under traditional sale and purchase agreements (SPAs). The contracts also provide for buyers and off-takers to cancel cargoes at relatively short notice (two months or less); the buyer or off-taker has to pay the liquefaction fee, but not the cost of natural gas that would have been supplied to the plant.

After an initial surge of interest from buyers between 2011 and 2013,[1] when high oil prices made the U.S. appear to be a significantly lower-priced source of LNG supply than oil-indexed product, commitments to U.S. output slowed. The start-up of projects that took FID between 2012 and 2015 has contributed to an oversupplied LNG market. U.S. developers, needing to secure commitments to planned output (required to underpin investment), have faced strong competition from planned developments in other countries including Canada, Mozambique, Papua New Guinea, Russia, and Australia.

In 2020, the Covid-19 pandemic, along with lockdowns imposed by governments to control the spread of the virus and associated economic dislocation, has increased uncertainty for LNG importers. Many are unwilling to make commitments to new supply until natural gas demand recovers for power generation and in downstream markets. Buyers and off-takers also have opted to cancel large numbers of U.S. cargoes, slowing down the growth of U.S. LNG production in 2020.

The impact of the Covid-19 pandemic on global LNG demand and prices led to the U.S. becoming a swing LNG producer in 2020. Companies committed to purchase or off-take U.S. LNG have used the terms of their SPAs and tolling agreements to cancel large numbers of cargoes because spot prices in Asia and Europe do not cover short-run marginal costs. Uncertainties about LNG demand also have put on hold final investment decisions (FIDs) for over 170 Mtpa of U.S. LNG projects, which have export permits from the U.S. Department of Energy (DOE)[2] and regulatory approvals from the Federal Energy Regulatory Commission (FERC). All but one of the FIDs targeted for U.S. projects in 2020 have been delayed to 2021 or later.[3] These delays will slow what is often referred to as the "second wave" of U.S. LNG export capacity.

With six export plants in operation as of August 2020, the U.S. had become the world's third-largest LNG producer. As production from the plants in operation builds up to full capacity and projects under construction are commissioned, and barring countervailing events, the U.S. could be on course to overtake Qatar and Australia to become the world's largest LNG producer and exporter by the mid-2020s. The question going forward is whether the U.S. LNG export businesses can remain on that fast track.

LNG Supply in August 2020

Projects in Operation

In August 2020, a total of 20 countries were exporting LNG. The number excludes Yemen, where liquefaction has been offline since April 2015 because of the civil war in the country. The total installed capacity in these 20 countries is an estimated 435.3 Mtpa. The Pacific Basin region had the most plants in operation and largest installed capacity in August 2020, with 170.1 Mtpa, followed by the Atlantic Basin, with 154.2 Mtpa (excluding the 5 Mtpa capacity SEGAS plant in Egypt, which has been out of action since December 2012 because of a lack of natural gas supply); the Middle East has 95.3 Mtpa in operation, and the Arctic region, where three-train Yamal LNG plant is in operation in Russia, has 17.5 Mtpa of capacity in operation.

However, with production from plants commissioned in late 2019 and the first seven months of 2020 building up to full capacity and natural gas supply shortfalls constraining production at plants in Algeria, Trinidad and Tobago, and Indonesia, available capacity was around 400 Mtpa in mid-2020. Global LNG production was 357.2 mt in 2019, which represented an 85% utilization of the capacity available during the year.

Qatar, which has installed capacity of 77.5 Mtpa at its Qatargas and RasGas plants, was the largest LNG producer in the world in 2019, with exports of 79.5 mt. Australia, which has 11 liquefaction plants in operation and a total capacity of 83.3 Mtpa, followed Qatar with 76.0 mt of production, an increase of 8.6 mt (12.8%) over 2018, attributable to production build-up from newly commissioned trains.

The U.S. was the third-largest LNG producer in 2019, with output of 35 mt. At the end of 2019, the U.S. had six LNG export plants in operation: Sabine Pass in Louisiana (five trains in operation), Corpus Christi in Texas (two trains), the single-train Cove Point plant in Maryland, Freeport LNG in Texas (two trains), Cameron LNG in Louisiana (one train), and two small-scale (0.25 Mtpa capacity) trains at Elba Island in Georgia. In the first seven months of 2020, two trains at Cameron LNG and one train at Freeport LNG, plus six more small-scale trains at Elba Island, were commissioned, taking the U.S. liquefaction capacity in operation to 69.4 Mtpa at the end of July 2020.

Argentina became the world's newest LNG exporter in 2019, when the Tango LNG floating liquefaction barge, which has been chartered by YPF from the Belgian shipping company, Exmar, for ten years, produced a first partial cargo in June of that year.[4] The barge, which has a capacity of 0.5 Mtpa and can store 16,100 m^3 of LNG, was originally built for an export project in Colombia, which was abandoned before the barge left the yard. It was moored at a berth in the port of Bahia Blanca, which was previously used by an FSRU importing LNG. Shale gas production from Argentina's Vaca Muerta region had led to the country having surplus natural gas production, especially during the summer months when demand is low. However, in June 2020, YPF sent a force majeure notice to the owner of Exmar, stating that is was unable to pay for the charter of the barge because of Covid-19. Exmar responded that the declaration of force majeure was "unlawful", but operations have ceased.[5]

Forecast Supply 2020–2035 from Projects in Operation in August 2020

At the end of 2019, before Covid-19 became a global pandemic, LNG supply was expected to increase by around 34 mt in 2020 taking it to 390 mt, as the production from projects commissioned in 2019 built up to full capacity and more projects were commissioned in 2020. It was assumed that the main growth markets for the additional output would be in China, South Asia, and Southeast Asia, while Europe would continue to act as the balancing market for any LNG not required by these markets or by markets in the Middle East and North Africa (MENA) and the Americas.

However, the outlook has dramatically changed as a result of the Covid-19 pandemic. Lower demand in key markets, where there have been lockdowns to control the spread of the virus, has slowed down the economic activity and has put downward pressure on prices, which, in mid-2020, fell to levels that no longer covered the short-run marginal costs of producing and transporting LNG to market, resulting in the cancellation of U.S. cargoes and producers in other parts of the world shutting-in capacity. Forecasts of production from liquefaction projects have had to be revised downward for 2020 and 2021. I have assumed that projects now in operation will return to operating at full capacity by 2022, provided the virus is under control by then. On this basis, production from projects in operation in August 2020 is forecast to increase from 357 mt in 2019 to 362 mt in 2020 and to 396 mt in 2024. Thereafter, output from these projects is forecast to decline steadily to 393 mt in 2025, 367 mt in 2030, and 338 mt in 2035 as liquefaction plants are shut down because facilities reach the age where continued production is no longer economic or as production is reduced because of a shortage of natural gas supply.

Liquefaction Capacity Under Construction in August 2020

In August 2020, a total of 102.4 Mtpa of liquefaction capacity was under construction globally. Table 4.1 lists these projects and shows when they are expected to start up. There are 14 large-scale onshore trains with

Table 4.1 Liquefaction capacity under construction in August 2020

Country	*Project*	*Capacity in Mtpa*	*Expected start-up*
Malaysia	Floating LNG Unit 2	1.5	4Q20
U.S.	Elba Island Trains 9–10	0.5	Oct-20
U.S.	Corpus Christi Train 3	4.8	1H21
U.S.	Sabine Pass Train 6	4.8	2H22
U.S.	Calcasieu Pass	10.0	1H23
U.S.	Golden Pass Trains 1–3	15.6	2024
Russia	Yamal Train 4	1.0	End-20
Russia	Arctic 2 LNG Trains 1–3	19.8	2H23
Canada	LNG Canada	14.0	Mid-24
Indonesia	Tangguh Train 3	3.8	1H22
Mozambique	Coral FLNG	3.4	2H22
Mozambique	Mozambique LNG Trains 1 and 2	13.1	mid-24
Mauritania/Senegal	Tortue LNG	2.5	1H23
Nigeria	Nigeria LNG Train 7	7.6	2H25
	Total	**102.4**	

Source: Author's proprietary database

capacities between 3.8 Mtpa and 7 Mtpa, 21 small-scale onshore trains with capacities ranging from 0.25 Mtpa (at Elba Island, Georgia, in the U.S.) to 1 Mtpa (Yamal LNG Train 4 in Russia), and three FLNG units with capacities between 1.5 Mtpa and 3.4 Mtpa.

The U.S. has 35.7 Mtpa of capacity under construction, which is 35% of the global total; Russia has 20.8 Mtpa (20%), and Mozambique has 16.5 Mtpa (16%). During the last four months of 2020, only 3 Mtpa of capacity (Russia's Yamal Train 4, the final two trains at Elba Island and Malaysia's second FLNG unit) is scheduled to start-up. Cheniere Energy's Corpus Christi Train 3 is the only project scheduled to start in 2021, but the commissioning of new capacity will gather pace from 2022. All the capacity under construction is scheduled to be in operation by the end of 2026, and full production of 102.4 Mtpa should be reached by 2027 or 2028.

Over the five-year period 2011–2015, FIDs were taken on an average of 25.4 Mtpa per year (Fig. 4.1). The fall in oil and LNG prices in mid-2014 led to a slowdown in new FIDs in 2016 and 2017, when commitments were made to only three projects with a total capacity of 9.7 Mtpa. For many of the planned projects, a barrier to taking FID was the failure to secure the new long-term commitments for the output that were needed to underpin the financing of the capacity.

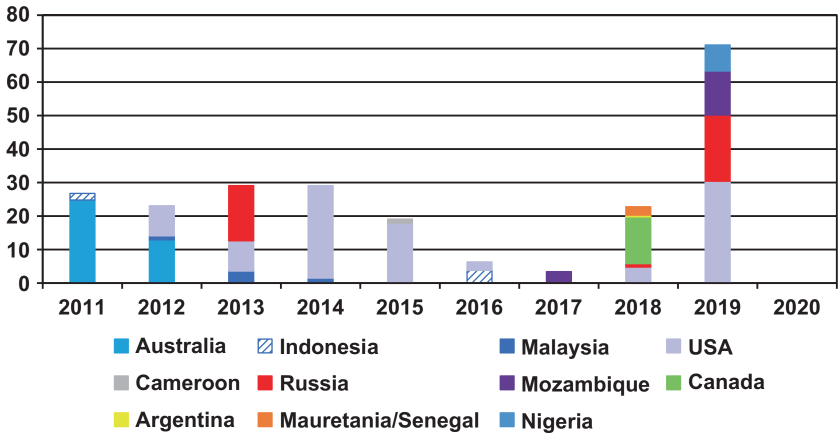

Fig. 4.1 Final investment decisions (FIDs) on liquefaction capacity, 2011–August 2020. (Source: Author's estimates)

In 2018, FIDs were taken on five new projects, with a total capacity of 22.8 Mtpa: small-scale units in Russia (Yamal LNG Train 4) and Argentina (Tango LNG unit), a third train at Cheniere's Corpus Christi plant, the Tortue FLNG on the maritime border between Mauritania and Senegal, and LNG Canada. In 2019, FIDs were taken on 71.1 Mtpa of capacity, a record for a single year, surpassing the total in 2005 when decisions were made on 50 Mtpa of capacity, including four 7.8 Mtpa mega-trains in Qatar.

The decisions taken in 2019 included 30.4 Mtpa of capacity in the U.S., through the sixth train at Sabine Pass (4.8 Mtpa) in Louisiana, Golden Pass LNG in Texas (15.6 Mtpa), and Calcasieu Pass in Louisiana (10 Mtpa). Commitments were also made to Mozambique LNG (13.1 Mtpa) and to Arctic 2 LNG in Russia (19.8 Mtpa), Novatek's second major project in the Arctic region. In December 2019, Nigeria LNG announced the go-ahead for its Train 7 project, which includes the debottlenecking of the existing six trains. No FIDs were taken in the first eight months of 2020.

Progress of Projects Under Construction

Malaysia—Floating Liquefaction Unit 2 Petronas's second floating liquefaction unit left the Samsung yard in South Korea in February 2020 and is now on location at the Rotan field, offshore Sabah.[6] In its first quarter 2020 results announcement, Petronas said that start-up is expected by the end of 2020. The output will be marketed by Petronas as part of its LNG sales portfolio.

U.S.—Elba Island The first eight 0.25 Mtpa trains were commissioned between November 2019 and July 2020, and start-up activities commenced on the final two trains in July. Shell has committed to lift all the output.

U.S.—Corpus Christi Train 3 In a corporate presentation on August 12, 2020,[7] Cheniere said that construction of the train was 90.5% complete and on course for commercial completion in 1H21.

U.S.—Sabine Pass Train 6 In the same presentation, Cheniere reported that construction was 63.9% complete, with commercial completion expected in 2H22.

U.S.—Golden Pass Qatar Petroleum (QP) (70%) and ExxonMobil (30%) took FID in February 2019 on the conversion of their Golden Pass receiving terminal to a liquefaction plant, which will have three 5.2-Mtpa trains. The output is being marketed by Ocean LNG, a joint venture LNG marketing company owned by the project partners.

U.S.—Calcasieu Pass In August 2019, Venture Global took FID on the 10 Mtpa Calcasieu Pass project in Louisiana.[8] Contracts have been secured for 8 Mtpa of output: from Shell (2 Mtpa), BP (2 Mtpa), Italy's Edison (1 Mtpa), Portugal's GALP (1 Mtpa), Poland's PGNiG (1 Mtpa), and Spain's Repsol (1 Mtpa). The plant will have eighteen 0.626 Mtpa trains arranged in nine blocks of two trains each, giving it a total capacity of 11.27 Mtpa, which means that there is clearly the potential for it to operate significantly above the nominal capacity. The trains are being built in a Baker Hughes facility near Florence in Italy and will be shipped to the site. Speaking at CWC/dmg's Japan LNG and Gas Summit in early July, Venture Global's Chief Commercial Officer, Tom Earl, said that construction had not been affected by Covid-19 and was on schedule for start-up in late 2022. The roof has been raised on the two storage tanks, and the first two cold boxes were delivered to the site by Chart Industries, four months ahead of schedule. He added that construction of the first of the trains had been completed in Italy.

Russia—Yamal LNG Train 4 When Novatek took FID on the 1 Mtpa train, which will test a Russian liquefaction technology called "Arctic Cascade", start-up was expected by the end of 2019. However, it has been delayed until "around the end of 2020", because of "technical problems with pipelines that are not designed for the extreme temperatures in the area".[9]

Russia—Arctic 2 LNG The 19.8 Mtpa Arctic 2 liquefaction project will have three liquefaction trains on gravity-based structures that are being constructed in a purpose-built yard in the Murmansk region. Start-up of the trains is scheduled in 2023, 2024, and 2026, respectively.[10] There have been cases of Covid-19 at the construction site, but, in June 2002, Novatek said that the outbreak has been brought under control and has not affected the schedule. Novatek has a 60% share in the project, and its partners, each with a 10% share, are Total, CNPC, CNOOC, and Japan Arctic LNG (Mitsui and JOGMEC). The partners will lift and market their equity shares of the output.

Indonesia—Tangguh Train 3 When FID was taken in mid-2016, the start-up was scheduled for mid-2020. However, in July 2019, it was announced that start-up had been delayed by 12 months, to 3Q21, because natural disasters across Indonesia had delayed shipments of materials and financial difficulties faced by a contractor had also hampered progress. Start-up has been further delayed because of Covid-19 and is now scheduled in the first half of 2022.[11]

Mozambique—Coral LNG Construction of the 3.4 Mtpa FLNG unit, which will be supplied with natural gas from the Eni-operated Block 4 offshore Mozambique, is reported to be still progressing on schedule for it to leave the Samsung yard in South Korea, as planned, in 2021 and for production to commence in mid-2022.[12] The hull was launched in January 2020, and work on installing the modules has started. BP has contracted to lift and market all the output from the unit.

Mozambique LNG FID was taken on the $20 billion, 13.1 Mtpa Mozambique LNG project in June 2020.[13] In the months leading up to the decision, Anadarko, the operator, was the target in a takeover battle between Chevron and Occidental. It was eventually won by Occidental, which was mainly interested in Anadarko's upstream assets in the U.S. It did a deal for Total to acquire Anadarko's African assets, including its 26.5% share in Mozambique LNG, and Total is now the operator of the project. Total announced in mid-July 2020 that it had signed loan agreements for US$14.9 billion for the project.[14] The loans are from 8 export credit agencies (ECAs), 19 commercial banks, and the African Development Bank. Start of production is targeted in 2024.

Total had to quarantine the site because of cases of Covid-19 in April 2020, and Islamic insurgency in Cabo Delgado province, where the plant is located, is a potential threat to the progress of construction. In August 2020, Total signed an agreement with the Government of Mozambique for security to be increased at the site.

Total's partners in the project are ENH, Mozambique's national oil company, (15%); Japan's Mitsui (20%); Indian companies ONGC (10%), Oil India (10%), and Bharat Petroleum (10%); and Thailand's PTTEP (8.5%). Eight LNG SPAs have been signed with buyers in Japan, China, India, Indonesia, Taiwan, and the UK, with Shell and with EDF Trading. The duration of contracts is reported to be from 13 years to 20 years, and several ways of pricing the LNG have been used—JLC (Japanese LNG

Cocktail—the average price of LNG imported into Japan), oil indexation with Brent, the UK's NBP, and the Netherlands' TTF. Two of the contracts are with joint buyers from different countries. This will allow cargoes to be switched between destinations depending on demand. The joint contract with Tokyo Gas and the UK's Centrica is unique since it involves buyers from Europe and Asia, who can take advantage of the project's location approximately equidistant from both markets.

Canada—LNG Canada When it announced FID in October 2018, Shell said the project was expected to be in operation by 2025.[15] This suggested a construction period of six to seven years, which was longer than would normally be expected for a liquefaction project, even in the relatively remote location in Kitimat in northwest British Columbia. However, the number of workers on the site was reduced by 65% after cases of Covid-19 were found on the site. Shell said that only non-time critical work was affected. TC Energy, which is constructing the 670 km Coastal Link pipeline from the reserves on the British Columbia/Alberta border, has reported that construction is on schedule. Agreement has been reached with all the First Nations on the route, some of whom had objected to construction.

The joint venture, partners Shell (40%), Petronas (25%), PetroChina (15%), Korea Gas (5%), and Mitsubishi (15%), will lift and market their equity shares of the output. Petronas and Mitsubishi have announced preliminary contracts for the sale of part of their share of the output.

Mauritania/Senegal—Tortue LNG In December 2018, FID was taken on the project, which will be supplied with natural gas from deep-water reserves in the Greater Tortue–Ahmeyim fields that straddle the maritime border between Mauritania and Senegal in West Africa. A Golar LNG ship, which came into service in 1976, is being converted to an FLNG unit, using the same design as the unit now in operation in Cameroon. The unit will have a capacity of 2.5 Mtpa and will moor at a purpose-built berth close to shore. First gas was targeted for the first half of 2022, but in April 2020, BP issued a force majeure notice to Golar, because Covid-19 had slowed work on the construction of a breakwater during the 2020 time-critical weather window, delaying the start-up of the project by around 12 months.[16] BP has committed to purchasing the entire output from the project on a free-on-board (FOB) basis.

Nigeria LNG Train 7 The final FID in 2019 was in the last days of December when commitment was announced to a 7.6 Mtpa expansion of the 22.2 Mtpa plant.[17] The additional capacity will be from a 4 Mtpa seventh train, with the other 3.6 Mtpa through debottlenecking the existing six trains. The announcement in December appears to have been premature since it was not until May 2020 that Shell announced that it had taken FID.[18] A consortium of Saipem, Chiyoda, and Daewoo has been awarded the Engineer, Procure and Construct (EPC) contract for project, which is referred to as "train 7" despite it being partially a debottlenecking of existing trains. Production is scheduled to commence in 2025, but the start of work is reported to have been delayed, so the schedule may slip.[19] The project's foreign partners, Shell, Total, and Eni, are expected to lift and market the output.

Forecast of Incremental Supply 2020–2035 from Liquefaction Capacity in Operation and Under Construction

Growth in LNG supply over the period to the mid-2020s will be mainly from the 102.4 Mtpa of liquefaction capacity under construction in August 2020, because it typically takes around four years to construct new liquefaction trains, plus a further 6–12 months for production to build up to full capacity. However, there is additional uncertainty over the build-up of production from these projects because of the impact of Covid-19 on the progress of construction. Several sites have had cases of Covid-19 in the first half of 2020, which has required the number of workers on site to be reduced.

Operators have to institute health checks and modify work practices, such as deep-cleaning equipment between shifts, to ensure the safety of their workforce. In addition, the virus will also have an impact on the transfer workers to and from sites, especially in remote locations, because of travel restrictions and fewer flights operating. Two projects under construction have already announced delays of up to 12 months in start-up because of Covid-19 (Fig. 4.2).

Pre-Covid LNG supply was forecast to increase by 34 mt in 2020, as output from trains commissioned in 2019 built up to full capacity and more trains were commissioned. The increase in supply was expected to slow to 14 mt in 2021 and 4.9 mt in 2022, because commitments were

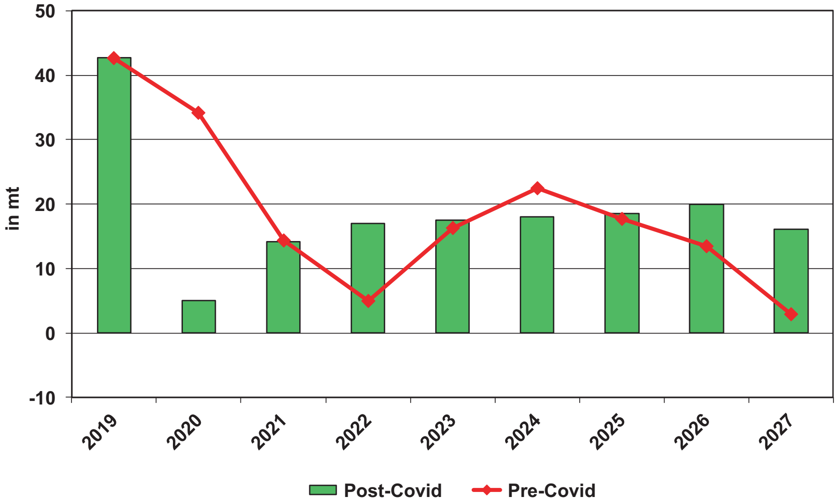

Fig. 4.2 Incremental LNG supply in the period 2019–2027 from projects in operation and under construction in August 2020; pre-Covid and post-Covid forecasts. (Source: Author's estimates)

made to a total of only 9.3 Mtpa of capacity in 2016 and 2017. Incremental supply growth was expected to accelerate from 2023 as projects on which FID was taken in late 2018 and in 2019 come on stream.

The post-Covid supply profile is very different. Low prices, slower demand growth, and U.S. cancellations will restrict the increase in incremental supply to a forecast 5 mt in 2020, but, on the assumption that the pandemic is brought under control in 2021 and the global economy returns to growth, LNG supply is forecast to increase by between 14 and 20 mt each year between 2021 and 2026.

Some of the new trains may operate above their design capacities, and output could, in some projects, be further increased through debottlenecking. This could add up to 20 Mtpa to output by the late 2020s, if it is assumed that all the new projects under construction and those commissioned in 2018, 2019, and the first six months of 2020 operate at 10% above design capacity. This has been achieved by some projects in recent years, including Cheniere which has increased the "run rate" capacity on its trains from the original 4.3–4.6 Mtpa to the current 4.7–5.0 Mtpa.[20]

However, the timing and the amount of additional production that will be available from other projects are uncertain. Furthermore, experience shows that some trains do not operate at full capacity because of technical problems or lower natural gas supply than had been expected. Furthermore, there may be delays in start-up or in the build-up of production, as has happened with some of the projects commissioned over the last few years. The Prelude FLNG unit in Australia is an example of a project where start-up has been delayed and production in the first year of operation has been well below capacity. Taking possible upsides and downsides to production into account, I have assumed that, in aggregate, the projects under construction and those recently commissioned will operate at around design capacity.

Figure 4.3 shows the forecast of LNG production from projects in operation and under construction in August 2020 and the pre-Covid forecast. The cumulative loss of production through cancellations of U.S. cargoes, lower output from non-U.S. projects, and delays in the projects under construction is approximately 160 mt.

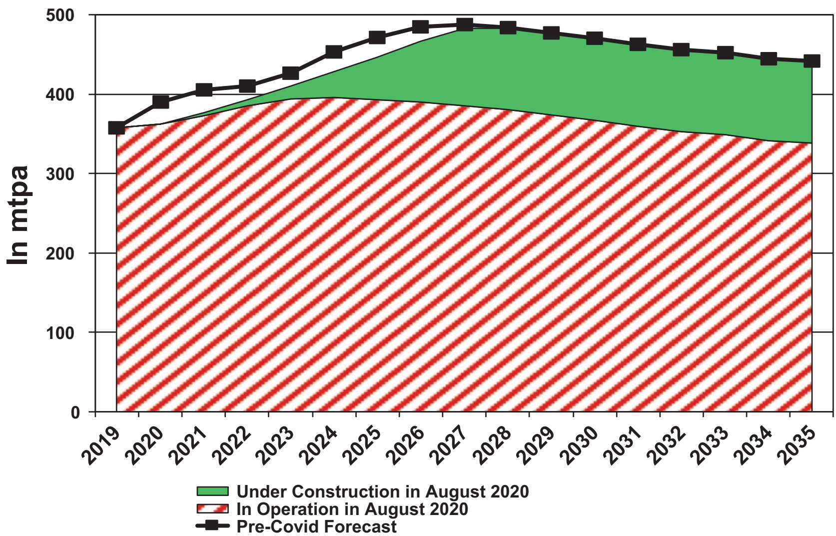

Fig. 4.3 Forecast global production from LNG plants in operation and under construction in August 2020. (Source: Author's estimates)

LNG Production from Projects in Operation and Under Construction in the U.S.

Six projects were operating in the U.S. in August 2020—five trains at Cheniere Energy's Sabine Pass plant in Louisiana, Dominion's 5.3 Mtpa, single-train plant at Cove Point in Maryland, two trains at Cheniere's Corpus Christi plant in Texas, three trains at both Cameron LNG in Louisiana and Freeport LNG in Texas, and eight small-scale trains at Elba Island. In 2019, a total of 35 mt was delivered to markets around the world from these projects, an increase of 14.5 mt over 2018. The expansion of U.S. liquefaction was, before Covid, expected to gather pace in 2020 and 2021 as output built up from newly commissioned trains. However, the cancellations of cargoes by buyers and off-takers, which started in April 2020, mean that the increase in output in 2020 will be significantly lower than originally expected. It is estimated that around 60 cargoes (3.9 mt) were cancelled in the second quarter of the year, with around 125 cargoes (8.2 mt) cancelled in the third quarter. The number of cancellations is expected to be lower in the fourth quarter as spot prices in Europe and Asia increase but, overall, U.S. exports are expected to increase by 6.8 mt in 2020 (Fig. 4.4), compared with forecast 24 mt at the start of the year.

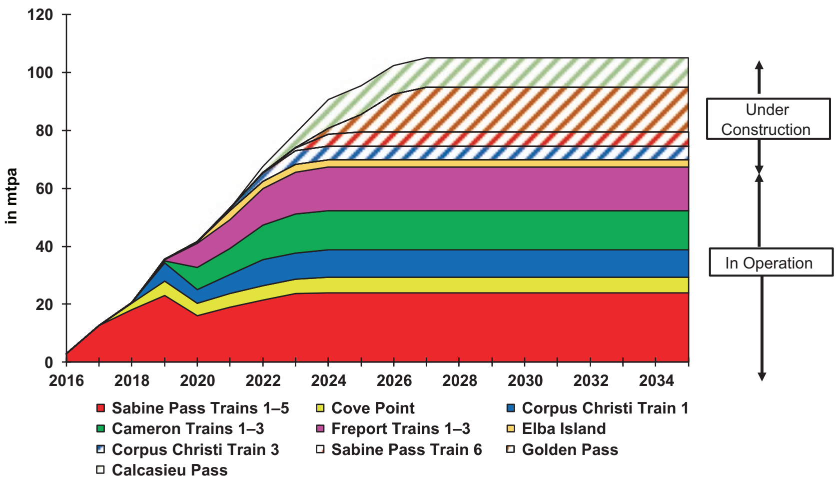

Fig. 4.4 Forecast production from U.S. LNG plants in operation and under construction in August 2020. (Source: Author's estimates)

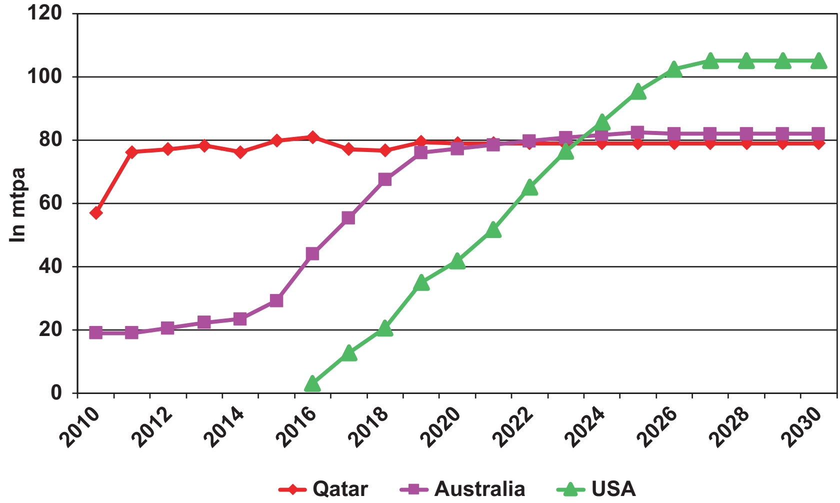

Fig. 4.5 LNG exports from Qatar, Australia, and the U.S., 2010–2030. (Source: Author's estimates)

The growth in U.S. LNG production will accelerate in 2021, provided the Covid-19 pandemic eases and global economic activity begins to recover. Production for projects in operation and under construction in the U.S. is forecast to increase to 95.5 mt in 2025 and reach full capacity of 105 mt by 2027, when all three trains at the Golden Pass terminal are producing at full capacity.

The U.S. share of global LNG production increased from 6.5% in 2018 to 9.8% in 2019 and is expected to have reached around 11.5% in 2020 despite the slower than expected growth rate. It is on course to overtake Qatar and Australia to become the world's largest exporter by 2024 or 2025, when its share of world LNG supply will be over 20% (Fig. 4.5).

Proposed LNG Projects

There is a long list of projects that are targeting filling the gap between supply and demand that is expected to emerge from the mid-2020s as LNG demand grows. In August 2020, proposals had been made for the development of projects with an estimated total capacity of 484 Mtpa (Table 4.2), of which just over 50% is in the U.S.

Table 4.2 Global liquefaction capacity, August 2020

	Capacity in Mtpa		
Country	*In operation*	*Under construction*	*Proposed*
USA	69.4	35.7	245
Canada	–	14.0	52
Mexico	–	–	25
East Africa	–	16.5	50
Australia	87.3	–	5
Qatar	77.0	–	49
Russia	28.5	20.8	30
Rest of Atlantic Basin	84.8	10.1	10
Rest of Pacific Basin	71.8	5.3	18
Rest of the Middle East	16.5	–	–
Total	**435.3**	**102.4**	**484**

Source: Author's proprietary database

The status of the proposed projects ranges from those with most of the requirements to take FID in place, including completion of front-end engineering design (FEED) and having secured regulatory approvals, to those at an early stage in the planning process. Consequently, the aggregate proposed capacity of 484 Mtpa should be considered indicative of intent rather than a forecast of the liquefaction capacity that will eventually be built.

At the beginning of 2020, the developers of 202.1 Mtpa of proposed capacity, 42% of the total shown in Table 4.2, said they are targeting FID in 2020. It was always unlikely that all the targeted FIDs will be achieved, given the success rate over the last decade when, on average, FID had been taken on around 30% of the targeted volume. In 2019, FID was taken on 71 Mtpa of capacity out of the targeted volume of 213 Mpta at the beginning of the year. A similar 30% success rate in 2020 would have added a further 60 Mtpa of capacity under construction, but with only three of the projects listed in Table 4.3 not having announced a delay in the first 8 months of the year, the outcome for the year could be no FIDs being taken.

In August 2020, the developers of three projects on which LNG had been targeted in 2020 had not ruled out a decision by the end of the year:

- Mexico—Sempra's Costa Azul conversion (2.5 Mtpa);
- U.S.—Venture Global's Plaquemines (20 Mtpa); and
- Qatar—Qatargas expansion phase 1 (33 Mtpa).

Table 4.3 Developers' targets for FID in 2020

Country	*Project*	*Operator*	*Capacity in Mtpa*
U.S.	Plaquemines	Venture Global	20.0
	Magnolia LNG	LNG Ltd	8.8
	Rio Grande LNG	Next Decade	9.0*
	Driftwood LNG	Tellurian	16.6*
	Port Arthur	Sempra LNG	11.0
	Freeport Train 4	Freeport LNG	5.0
	Texas LNG	Texas LNG	2.0
	Annova	Annova LNG	6.0
	Delfin LNG	Delfin LNG	3.0*
	Corpus Christi LNG Phase 3	Cheniere	9.5
	Lake Charles	Energy Transfer	16.5
	Total USA		***107.4***
Mexico	Costa Azul Phase 1	Sempra LNG	2.5
Qatar	Qatargas Expansion	Qatargas	33.0
Mozambique	Rovuma LNG	ExxonMobil	15.2
PNG	PNG LNG Expansion	ExxonMobil	2.7
	Papua LNG	Total	5.4
Russia	Ob LNG	Novatek	4.8
Canada	Woodfibre LNG	Pacific Oil and Gas	2.1
	Goldboro LNG	Pieridae	10.0
	LNG Canada Expansion	Shell	14.0
Australia	Pluto Train 2	Woodside	5.0
	Total non-USA		***94.7***
	Total		**202.1**

*Assumes partial FID on full project scope

Source: Author's proprietary database

Mexico—Costa Azul Conversion Sempra plans to convert the little used Costa Azul receiving terminal in the Baja California region of Mexico to a liquefaction plant to be supplied with natural gas from the U.S. It is on the West Coast and will be able to take advantage of the shorter shipping time to Asian markets. The first phase is the construction of a 2.5 Mtpa train, and there is the potential to add two 5.5 Mtpa trains in the future. In November 2018, Total, Tokyo Gas, and Mitsui signed Heads of Agreements for 0.8 Mtpa each from the project. In May 2020, Sempra said that binding SPAs had been signed with Total and Mitsui, and FID was expected by the end of the second quarter.[21] However, in July 2020, Sempra's Mexican subsidiary, IEnova, said they were waiting for a final permit from the Mexican government, which had been delayed due to Covid-19.[22]

U.S.—Plaquemines Venture Global is planning to build a 20 Mtpa plant on the right bank of the Mississippi in southern Louisiana. It will use the same technology as the company's Calcasieu Pass project. The company has ordered thirty-six 0.626 Mtpa trains from the Baker Hughes plant in Italy for this and its Calcasieu Pass project. In June 2020, FERC gave approval for Venture Global to proceed with an initial mobilization and limited site preparation. Venture Global had previously said that it intended to start work on the site in mid-2020 before financial close (FID) in late 2020.[23] It currently has 20-year SPAs for output from the plant, with Poland's PGNiG for 2.5 Mtpa and with EDF Trading for 1 Mtpa.

Qatar—Qatargas Expansion In November 2019, Qatar Petroleum (QP) announced it will add two 8 Mtpa mega-trains to its originally planned expansion of four mega-trains, taking Qatar's total liquefaction capacity to 126 Mtpa (from 77 Mtpa currently) by 2027.[24] The expansion is being planned in two phases. Work is underway offshore for the first phase, North Field East, which will supply the first four of the new trains. The second phase, North Field South, will supply natural gas to the two additional trains. There have been some delays, including in the selection of foreign partners for the first four trains and in the awarding of EPC contracts.

Qatar is negotiating with partners in the existing trains, ExxonMobil, Total, Shell, and ConocoPhillips, along with Eni, Equinor, and Chevron. Russian and Chinese companies and buyers of the output are also possible partners. However, Saad Al-Kaabi, the chairman and CEO of Qatar Petroleum, has said that Qatar does not need partners and will go ahead with the development on its own if it does not receive acceptable offers. He has also said that QP is prepared to take the market risk and so does not need long-term contracts with buyers, although Qatargas is active in the market seeking commitments from buyers, and is thought to be prepared to offer competitive prices. The discussions are taking place in parallel with negotiations with Japanese and Korean buyers over the extension of existing long-term contracts for around 11 Mtpa that expire between the end of 2021 and 2024.

A decision on foreign partners was expected by late 2019 or early 2020, but it is still awaited. In April 2020, Saad Al-Kaabi said that Qatar is fully committed to the expansion despite the Covid-19 crisis.[25] However, the start of production has been deferred from 2024 to 2025, following a delay in the EPC bidding process, with the final train expected to start-up in 2027.

Qatar has signaled its intent to proceed with the expansion by signing ship-building agreements with Chinese and Korean yards. The first, in April 2020, was with the Hudong yard in China for eight firms and eight options for ships with a capacity of 175,000 cubic meters (cm).[26] The orders are subject to Chinese buyers committing to purchase the output from the expansion trains and, of course, FID on the expansion. A few weeks later, Qatar signed contracts for the supply of more than 100 ships at a cost of US $19.1Bn from Korea's three major shipbuilders—Daewoo, Hyundai, and Samsung—for delivery between 2024 and 2027.[27] No details have been released on the split of the orders between the yards or how many ships will be for the expansion, how many will replace older steam ships currently in operation, and how many will be for QP's 70% share in the 15.6 Mtpa Golden Pass project in the U.S.

Qatar's approach to the expansion appears to be to continue to progress the development without formally announcing FID. The key decision will be the awarding of the EPC contract for the first four trains, which I expect to happen in early 2021, with an award on the additional two trains probably delayed until 2022 or even 2023.

Deferred FIDs on U.S. LNG Projects

The remaining projects listed in Table 4.3 have announced delays in FID into 2021 or in some cases an indefinite delay. No project has been abandoned, although the reality is that the prospects for some of them are poor, as they run low on funds or find it impossible to secure commitments for the output. There is, however, a surprising level of optimism from developers, especially in the U.S., over the prospects for their projects. There have been changes in the plans for some of the projects, including redesigning of the facilities and changes of ownership.

Magnolia LNG LNG Ltd., the Australian listed company developing the planned 8.8 Mtpa project in Lake Charles, Louisiana, ran out of money to continue the development, and it was put up for sale in early 2020. The project and LNG Ltd.'s Optimized Single Mixed Refrigerant (OSMR) liquefaction technology were finally acquired by Glenfarne,[28] a privately owned energy and infrastructure development and management company, for US$2 million, after deals with two other companies fell through. Glenfarne has not said what its plans for the project are. LNG Ltd. has retained its second project, Bear Head LNG, in eastern Canada, and the rights to use the OSMR technology there, but the probability of the project being developed is low.

Rio Grande LNG In the last 12 months, Next Decade has not secured any more commitments from buyers to add to the 2 Mtpa agreement with Shell for output from the 27 Mtpa plant that it plans to build in Brownsville, Texas. It has reengineered the design to reduce the number of trains from six to five while maintaining the capacity at around 27 Mtpa. It claims that the redesign will reduce CO_2 emissions. It has also sold the planned Rio Bravo pipeline, which will supply natural gas to the plant, to Enbridge. In May 2020, it said that it had sufficient capital resources to sustain operation through to the end of 2021, by which time it expects to have taken FID.[29] Next Decade's strategy of using large-scale liquefaction trains differentiates it from other U.S. developers including Venture Global, Tellurian, and Cheniere, who are planning smaller-scale trains (0.6–2 Mtpa), which they say give more flexibility in scheduling construction in line with the requirements of buyers.

Driftwood LNG Tellurian's novel business model for its 27 Mtpa Driftwood LNG project in Louisiana requires buyer to invest $0.5 billion and agree to service $1 billion of debt to secure the right to 1 Mtpa of LNG for the life of the project. The investments plus loans will be used to purchase natural gas in the ground, to develop production and pipelines to transport gas to the plant, and to construct the plant. Investors pay the cost of servicing the loans, the operating costs of producing and piping the natural gas to the plant, and the cost of liquefying LNG that they lift. Tellurian estimates that operating costs will be between $3 and $4/MMBtu.[30] In October 2019, Tellurian signed a Memorandum of Understanding (MOU) with Petronet for the investment of $2.5 billion in Driftwood LNG to lift 5 Mtpa from the plant. This added to the preliminary agreements with Total for 1 Mtpa of capacity and 1.5 Mtpa of purchases and with Vitol for the purchase of 1.5 Mtpa. It appeared that Tellurian had secured sufficient commitments to support first-phase investment in 11 Mtpa of capacity, provided, of course, the preliminary agreements were turned into binding contracts. It was agreed that Tellurian and Petronet would target a final contract by the end of March 2020, which was extended by two months, but, at the end of May, Petronet allowed the MOU to expire. The prospects for the Driftwood project appeared to have improved in July when Petronet agreed to restart negotiations to turn the MOU into a binding commitment, but Petronet warned in August that it is re-evaluating its plans and would come up with a fresh decision soon. Tellurian has also decided to remove three of the four pipelines it originally planned to build to supply natural gas to the plant, because of the need to reduce costs.

Sempra's 11 Mtpa **Port Arthur** project in Texas has appeared to be in a stronger position to take FID than many of its competitors in the U.S. It has an HOA (Heads of Agreement) with Saudi Arabia's Aramco to purchase 5 Mtpa of LNG and to negotiate the acquisition of a 25% share in the project, and a definitive SPA with Poland's PGNiG for 2 Mtpa. In early January 2020, Sempra and Aramco announced the signing of an interim project participation agreement. Sempra said at the time that it intended to take FID in 3Q20, but in May, it accepted that FID that year was no longer realistic and the decision had been delayed to 2021, "because of the market uncertainty caused by the coronavirus pandemic".

Freeport LNG (5 Mtpa) has FERC and DOE approval for a proposed 5 Mtpa fourth train and a binding HOA with Sumitomo for 2.2 Mtpa of capacity in the plant on a tolling basis. However, market uncertainty means FID has been delayed. Freeport LNG has been given approval by FERC for a delay of three years, until May 2026, in the date by which it has to start production from the train. As an expansion of an operating project, it should be well placed to take FID when the market improves.

Annova (6 Mtpa), Texas LNG (2 Mtpa), and Delfin LNG (3 Mtpa) are three U.S. projects with regulatory approvals in place but no commitments from buyers or off-takers for the output. They are all now targeting FID in 2021.

Corpus Christi Phase 3 (10 Mtpa) In November 2019, Cheniere received FERC approval for phase 3 of the development of its Corpus Christi plant, which will consist of seven mid-scale liquefaction trains with a total capacity of approximately 10 Mtpa. At the time it said that FID, which was planned for 2020, was contingent on clinching an EPC contract and acquiring essential financing and contracts for the output. During the presentation of the company's 1Q20 results, Jack Fusco, the CEO, said: "because of all the issues – coronavirus, the warm winter – the whole urgency among customers to sign long-term contracts has dropped. It will be tough to continue to get our fair share of contracts and continue to commercialise phase 3 at this point".[31] However, as an expansion of an operating project by a company with a track record of performance, it should be in a strong position to secure the contracts it needs when buyers decide to commit to new supplies.

Lake Charles (16.5 Mtpa) In March 2019, Shell and Energy Transfer (the owner of the Lake Charles receiving terminal) signed a Project Framework Agreement to advance the Lake Charles liquefaction project jointly. It brought Shell back into active participation in a project for which they appeared to have given low priority after becoming a partner through the acquisition of the BG Group in 2016. Twelve months later, in May 2020, Shell announced it would not go ahead with equity involvement in the project,[32] presumably as part of its program to reduce capital expenditure. Energy Transfer said it would take over the role of lead project developer and evaluate various options for the project, including the possibility of bringing in one or more equity partners and reducing the size of the project from three (16.5 Mtpa) to two trains (11 Mtpa).

Deferred FIDs on Non-U.S. LNG Projects

Mozambique—Rovuma LNG In October 2019, ExxonMobil (25%) and its partners Eni (25%), CNPC (20%), Portugal's GALP (10%), Korea Gas (10%), and ENH (10%) said they planned to invest US \$500 m in the initial construction plans for the 15.2 Mtpa project, but a full FID, which ExxonMobil had earlier said would be by the end of the year, was delayed to the first half of 2020. A consortium of JGC, Technip, and Fluor was awarded the EPC contract for the project. ExxonMobil has now said that FID has been delayed "until market conditions are right".[33]

PNG LNG and Papua LNG (8.1 Mtpa) Negotiations between the government of PNG and ExxonMobil over the terms for the development of the P'nyang broke down in January 2020, which halted progress on the joint development of 8.1 Mtpa of capacity through the construction of three identical 2.7 Mtpa trains: a third train at PNG LNG supplied from the P'nyang field and two trains at Papua LNG supplied from the Elk and Antelope fields in the Southern Highlands region. In its 2Q results announcement in July 2020, Oil Search, a partner in both projects, reported that exploratory talks with the PNG government had continued, and in May, the government and ExxonMobil had restarted discussions on the P'nyang agreement. However, because of Covid-19, ExxonMobil and Total, the operators of PNG LNG and Papua LNG, respectively, demobilized the majority of their LNG technical and commercial staff, which means there is likely to be an extended delay to the expansion. In August, Oil Search's CEO said that he was confident that the PNG expansion and

Papua LNG projects would go ahead in time to meet a window of demand for new LNG in 2027.[34]

Russia Ob LNG (4.8 Mtpa) Novatek's plans for a third project in the Arctic have been put on hold because of Covid-19. It is determined to go ahead with the project and is probably prepared to take FID without firm commitments from buyers. Consequently, FID in 2021 is possible.

Canada Woodfibre LNG (2.1 Mtpa) In March 2020, Woodfibre LNG announced a delay of a year to FID because a fabrication yard in China had been shut down due to Covid-19 and the preferred U.S. construction contractor for the marine facilities had filed for Chapter 11 bankruptcy and was not able to start work as expected.[35] It is now three years since Sakunto Tanoto, the billionaire owner of Singapore's Royal Eagle Group, of which Woodfibre is a subsidiary, released the funds for the project.

LNG Canada Expansion (14 Mtpa) FID in 2020 seemed to be more of an aspiration for Shell (40%) and its partners, Petronas (25%), PetroChina (15%), Mitsubishi (15%), and Korea Gas (5%), than an expectation, so a delay is not a surprise.

Canada—Goldboro LNG (10 Mtpa) Goldboro LNG is the only LNG export project still being actively progressed in eastern Canada. The operator, Pieridae LNG, has managed to keep alive the agreement for 5 Mtpa from the first of the two trains with Germany's Uniper, which was signed in 2013. The agreement also means that the project is eligible for $4.5 billion of loan guarantees from the German government. However, it suffered a setback when its deal to acquire Shell's reserves in Alberta to supply the plant was blocked by the province's regulator. Pieridae had selected KBR as the EPC contract, but KBR had said it will no longer carry out the work under a fixed price contract; hence, Pieridae is now looking for a new contractor.

Australia—Pluto LNG Train 2 (5 Mtpa) In July 2020, Woodside, facing a fall in revenues because of low oil and LNG prices, said that it was delaying a decision on its two largest projects, Scarborough and Browse, until the second half of 2021 and 2023, respectively, at the earliest.[36] The development of the offshore Scarborough field, in which Woodside has a 75% share that it acquired from ExxonMobil, with BHP owning the other

25%, is planned to supply a second train at the Pluto plant, to be owned 100% by the company. The Browse development is intended to backfill the North West Shelf project, which is expected to run short of natural gas supply, as reserves in the fields currently supplying the plant are depleted.

Woodside has not been able to secure commitments from buyers for output from Pluto Train 2 in the current environment. It has also failed to receive support from its partners in Browse for the development of the reserves to supply the North West Shelf project. We could see some changes to the NWS Joint Venture following Chevron's decision to sell its 16.7% share. It is also possible that Scarborough could be a supply source for the North West Shelf plant rather than for a second train at Pluto.

The Status of Other Proposed Projects

The earlier section focused on projects that were targeting FID in 2020. They account for 42% of the proposed capacity. The projects making up the other 58% are at an earlier stage in the planning process and face the challenges of securing commitments from buyers, reducing costs, gaining regulatory approval, and raising finance.

Covid-19 and the collapse in oil demand have led many organizations to lower their forecast of oil and natural gas prices, and LNG project developers have responded by looking at the ways to reduce capital costs to ensure the economic viability of proposed investments. Cost reduction is also important in positioning projects to be able to meet LNG buyers' demands for more flexible terms in new contracts. They want lower take-or-pay levels, prices that respond more quickly to changes in their markets, and the removal of destination clauses, which restrict their ability to divert LNG cargoes to terminals other than those they own or use. They need greater contractual flexibility to help them manage increasingly uncertain demand in their downstream power and gas markets.

Aggregators, such as Shell, BP, Chevron, Gazprom and Total, provide one option to manage the disconnect between developers, who require long-term commitments from buyers with a strong credit rating, and buyers who are looking for short-term and more flexible contracts and, in some cases have a lower credit rating and lack LNG experience. Aggregators can commit to purchase or off-take LNG on a long-term basis and market it on a short- or medium-term basis to buyers, who are not prepared to contract on a long-term basis or have low credit ratings. In the process, aggregators take over some of the volume and off-take risk from developers.

BP's commitment to the entire output from the Coral project in Mozambique and from the Tortue project in Mauritania and Senegal exemplifies an aggregator providing the off-take security that a new project requires. BP will take the output from both projects into its supply portfolio, which it markets through a mix of spot, short-, medium-, and long-term contracts. BP and Shell have taken similar roles in Venture Global LNG's Calcasieu Pass project in the U.S., with each committing to purchase 2 Mtpa from the planned 10 Mtpa plant.

The LNG Canada and Golden Pass projects are examples of a new business model where FID is taken with project shareholders taking the responsibility of marketing their equity shares of output rather than the project signing long-term deals with power and gas utilities, the typical business model in the past. However, the impact of Covid-19 and lower prices on major oil and gas companies may make them more cautious about taking on volume and price risks by making new long-term commitments to the output from projects in which they are a partner or to third-party projects.

Proposed LNG Projects in the U.S.

The first wave of U.S. LNG export projects, on which FID was taken between July 2012 and November 2016, was in operation in August 2020, with the exception of two 0.25 Mtpa trains at Elba Island. The anticipated second wave of U.S. projects has struggled to progress. Since the end of 2016, Cheniere has committed to single 4.8 Mtpa train expansions to its Sabine Pass and Corpus Christi projects, ExxonMobil and Qatar Petroleum have committed to the 15.6 Mtpa Golden Pass project, and Venture Global to its 10 Mtpa Calcasieu project, but there is a long list of projects that have full regulatory approval or are seeking that approval where construction has not yet started.

Regulatory Approvals for U.S. LNG Exports

The key approvals developers need at the federal level are from the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC). DOE's role is to approve the export of U.S. natural gas to countries with which the U.S. has a Free Trade Agreement and to non-FTA countries. The Natural Gas Act 1938[37] requires DOE to approve applications for exports to FTA countries without modification or delay, which makes approval a formality.

In the case of exports to non-FTA countries, DOE must consider the impact on the U.S. natural gas market and prices in deciding whether to approve the application. When plans for LNG exports from the U.S. were first announced, DOE said it would review applications in the chronological order in which they were submitted. In 2014, as the queue of applications built up, with 24 pending, DOE announced it would only review applications after a project received approval from FERC. This ensured DOE only considered commercially mature projects with environmental and other approvals in place.

Securing FERC approval for the siting, construction, and operation of an LNG export plant is more demanding in terms of time and cost than securing DOE approval. FERC must consider the impact of the project on the environment, consult local communities, and ensure that it can be constructed and operated safely. Project developers must invest in environmental studies and produce a detailed design of the planned facilities. FERC review of an application typically takes up to 18 months, and the cost of preparing the application and responding to FERC requests for additional information and clarification reportedly can reach up to $100 million. The time taken and the financial costs of the FERC approval process ensure that only companies with access to funds and seriously committed to development are likely to reach the stage of preparing and making an application to FERC.

The FERC website lists projects that have received approval but have not yet started construction, have filed an application with FERC, or are in pre-filing stage with FERC; this gives an indication of the projects in which developers are prepared to invest the necessary funds to advance them to a stage where they are positioned to take FID. Table 4.4 summarizes the status of proposed U.S. LNG projects on May 29, 2020, according to the FERC website.

Fourteen projects (including Alaska LNG), with a total design capacity of 163 Mtpa, had been approved by FERC by May 2020 for the siting, construction, and operation of the planned liquefaction plant and by DOE for the export of the output to both FTA and non-FTA countries. In addition, the 13 Mtpa capacity Delfin project, which will use four floating liquefaction (FLNG) units, has completed permitting with the Coast Guard and the U.S. Department of Transportation's Maritime Administration (MARAD) and has DOE approval for exports to FTA and non-FTA countries. From the regulatory standpoint, these projects are in position to take FID, but they still need to secure commitments from buyers or off-takers for the planned output to support the financing of the investment. Table 4.5 lists the projects that are at this stage.

Table 4.4 Planned U.S. LNG export projects

	Capacity	
	FERC application in Bcf/d	*Design in Mtpa*
Approved construction not yet started	24.16	143.0
Approved by MARAD Construction but not yet started	1.80	13.0
Alaska LNG (approved by FERC construction but not yet started)	2.63	20.0
Proposed to FERC	3.04	19.4
Projects in pre-filing with FERC	5.51	49.5
Total	**37.14**	**244.9**

Source: FERC Website dated May 29, 2020

For Table 4.4 through Table 4.6, https://www.ferc.gov/industries-data/natural-gas/overview/lng

Table 4.5 U.S. export projects with full regulatory approval not yet under construction

Project	*Location*	*Developer*	*Capacity in Mtpa*
Lake Charles LNG	Lake Charles, Louisiana	Energy Transfer	16.5
Magnolia LNG	Lake Charles, Louisiana	LNG Limited	8.8
Cameron LNG Trains 4 & 5	Hackberry, Louisiana	Sempra	10.0
Port Arthur LNG	Port Arthur, Texas	Sempra	11.0
Driftwood LNG	Calcasieu, Louisiana	Tellurian	27.6
Freeport LNG Train 4	Freeport, Texas	Freeport LNG	5.0
Gulf LNG	Pascagoula, Mississippi	Kinder Morgan	10.0
Texas LNG	Brownsville, Texas	Texas LNG	4.0
Rio Grande LNG	Brownsville, Texas	NextDecade	27.0
Annova LNG	Brownsville, Texas	Annova LNG	6.0
Corpus Christi Phase 3	Corpus Christi, Texas	Cheniere	9.5
Jordan Cove	Coos Bay, Oregon	Pembina	7.6
Alaska LNG	Nikiski, Alaska	Alaska Gas Line	20.0
Delfin LNG	Offshore Louisiana	Delfin LNG	13.0
	Total		**176.0**

Source: From table on FERC website dated May 29, 2020

All the projects are in Louisiana and Texas, except for Jordan Cove, which is in Oregon on the West Coast, and Alaska LNG. The list includes three expansions of operating plants plus one offshore project using FLNG units.

There were two projects that were being reviewed by FERC in August 2020 and four projects in pre-filing (Table 4.6).

Table 4.6 Applications to FERC for LNG Exports

Project	*Location*	*Developer*	*Capacity in Mtpa*
Filed			
Commonwealth LNG	Cameron, Louisiana	Commonwealth LNG	9.0
Port Arthur LNG	Port Arthur, Texas	Sempra	11.0
	Total Filed		**20.0**
In pre-filing			
Port Fourchon LNG	Lafourche, Louisiana	Energy World Corp	5.0
Galveston Bay LNG	Galveston, Texas	NextDecade	16.5
Pointe LNG	Plaquemines, Louisiana	Pointe LNG	8.0
Delta LNG	Plaquemines, Louisiana	Venture Global	20.0
	Total in pre-filing		**49.5**

U.S. LNG Export Business Models

Three basic business models are being used for U.S. LNG projects:

Free-On-Board Sales

In this model, the project developer is responsible for arranging the supply of natural gas, piping it to the liquefaction plant, liquefying it, and loading it onto buyers' ships. The buyers are responsible for arranging the shipping to transport the cargo to market. Provided the project developer has obtained approval from DOE to export LNG to non-FTA countries, there are no restrictions on the destinations to which the buyer can transport cargoes. Cheniere Energy chose the free-on-board (FOB) sales model for its Sabine Pass and Corpus Christi projects, and it has also been chosen by Venture Global for its Calcasieu Pass project, which is under construction, and for its two planned projects in Plaquemines Parish in Louisiana. The FOB price is the sum of the cost of natural gas delivered to the plant and a liquefaction fee.

The buyer contracts to purchase and lift LNG on a long-term basis. However, in the case of most of Cheniere's SPAs, the buyer has the right to cancel cargoes by giving notice by the 20th day of the month, two months before a cargo is scheduled to be lifted. When buyers exercise that right, as they have done in 2020, they pay the liquefaction fee but do not have to pay for the natural gas. Liquefaction fees for Cheniere projects range between \$2.25/MMBtu and \$3.50/MMBtu, 85–90% of which is fixed for the life of the contract; the remaining 10–15% escalates with

U.S. inflation and covers the plant operating cost. The majority of liquefaction fees for Cheniere projects are in the public domain because the contracts Cheniere signed with buyers had to be reported to the U.S. Securities and Exchange Commission.

Tolling

In this model, the buyer is responsible for securing natural gas supply and arranging its transport by pipeline to the plant. The plant owner is responsible for building and operating the liquefaction plant and using it to liquefy buyers' natural gas. Off-takers (companies who have entered into tolling contracts) arrange the shipping to transport the LNG to market. They commit to liquefaction capacity in the plant, typically for 20 years, and pay the tolling fee regardless of whether or not they use the capacity. The arrangements for electing not to lift a cargo are written into the contracts, but less notice than for the FOB model is typically required, since it is the off-taker, not the plant owner, who arranges the supply of natural gas to the plant. Tolling fees are not in the public domain, because the companies that have developed projects using this model are either privately owned or owned by large corporations for which LNG is only a part of their business. However, the general view is that, while tolling fees vary between projects, they are similar to the liquefaction fees in the FOB sales model.

Integrated

A small number of the planned projects are being developed using the traditional integrated project structure, in which the natural gas reserves are dedicated to the project and are owned, or natural gas is purchased on a long-term basis from upstream producers, by the project developers. ExxonMobil and QP have structured their Golden Pass project this way. ExxonMobil has invested heavily in shale gas reserves and production in the U.S., while, in June 2018, Saad Al-Kaabi, CEO of QP, announced plans to invest $20 billion in U.S. oil and natural gas, some of which would go to lining up supply for the Golden Pass plant.[38]

Tellurian has announced a novel integrated structure for its planned 27 Mtpa Driftwood LNG project (see "Deferred FIDs on U.S. LNG Projects" section). Alaska Gasline Development Corporation's planned Alaska LNG project will also use an integrated project structure, with reserves on the North Slope dedicated to supply the plant, and it will build a pipeline from the north of the state to the plant site at Nikiski on the Cook Inlet in the south.

How Competitive Is U.S. LNG?

U.S. LNG developers offer LNG buyers and off-takers several alternative project structures, giving them the opportunity to be involved in parts of the LNG chain, from arranging natural gas supply and investment in the plant in the tolling model to all parts of the LNG chain in the Tellurian model. The ability to deliver cargoes to any destination without the requirement to seek the permission of the seller or to share extra revenues that may be generated by the diversion of cargoes is important to many buyers, who have complained for many years about the unfairness of restrictive destination clauses in LNG contracts.

The ability to cancel cargoes at relatively short notice has been described as an advantage to the buyer because it helps them balance supply with demand in their downstream markets. However, it comes at a price, because the liquefaction or tolling fee has to be paid regardless of whether or not the cargoes are lifted. The liquefaction fee will, in most circumstances, be lower than a take-or-pay payment under the terms of a traditional sales and purchase agreement, which required payment at the prevailing contract price if the buyer takes less than the annual contract quantity minus any downward quantity tolerance (DQT) allowed under the terms of the contract. However, the payment for a cargo not taken can be offset against the cost of the cargo when it is taken as make-up at a later date. U.S. sales and tolling contracts do not have any DQT provisions, which are 10% each year, subject to a cumulative cap, in many Asian contracts. Furthermore, the liquefaction fee for a cancelled U.S. cargo cannot be recovered. There are very few cases of a payment being made for cargoes not taken in traditional take-or-pay contracts in Asia over the long history of the LNG business, but, as is discussed later, cancellation fees for U.S. cargoes that have not been lifted in 2020 already amount to well over $1 billion.

A key consideration for buyers deciding whether to buy U.S. LNG or LNG from other sources is how price competitive U.S. LNG will be over the life of the contract. According to the 2020 edition of the International Gas Union's *Wholesale Gas Price Survey*, which was published in June 2020, the price of 59% of the LNG sold in 2019 was indexed to crude oil or oil products. This compares with 72% in 2017. The share of U.S. LNG exports, which under the FOB sales model or the tolling model are indexed to U.S. natural gas prices, increased from 4.4% in 2017 to 9.8% in 2019. Making a long-term commitment to LNG indexed to U.S. natural gas prices presents both an opportunity and a risk for buyers as U.S. gas prices and crude oil prices now move independently of each other.

U.S. LNG prices are essentially cost-based rather than indexed to another commodity. The FOB price under a sales or tolling contract is the sum of the cost of the natural gas supplied to the plant and the liquefaction or tolling fee. In the case of Cheniere projects, the cost of natural gas is 15% uplift on the Henry Hub price. The uplift covers the cost of natural gas used in the liquefaction plant and other costs incurred in purchasing the natural gas and delivering it to the plant. The liquefaction fee is between \$2.25/MMBtu and \$3.50/MMBtu in the contracts Cheniere signed between 2011 and 2016. The FOB prices in tolling contracts for other U.S. LNG projects are not in the public domain. However, they are thought to have a similar structure to the Cheniere contracts, but the percentage of the natural gas consumed in the plant may be different—for example, the Freeport LNG plant uses electric motors rather than gas turbines to drive the compressors, and as a result, significantly less natural gas is consumed. However, power supply to the plant has to be purchased.

The cost of natural gas supplied to plants by companies with tolling contracts depends on how they procure the supply and where it is produced. Consequently, it is probably linked to the price at a different U.S. natural gas trading hub rather than directly to the price at Henry Hub. However, in the analysis later in the chapter of the competitivity of U.S. LNG exports, the Cheniere price formula has been used.

Shipping costs depend on the distance to market, the charter rate for the LNG ship, the cost of fuel (boil-off gas and fuel or marine diesel), port costs, and the transit fee, if the Panama Canal is used. Assuming a modern diesel-engine ship with a capacity of 170,000 m^3 using the Panama Canal, shipping costs for delivery of LNG from the Gulf of Mexico to Northeast Asia (Japan, South Korea, China, and Taiwan) range between \$1.40/MMBtu and \$1.80/MMBtu. Thus, an indicative price of U.S. LNG delivered to Northeast Asia $P(LNG)_{nea}$ is expressed by the equation:

$$P(LNG)_{nea} = 1.15 \times P(HH) + B \tag{4.1}$$

Where P(HH) is the Henry Hub natural gas price
And B is between \$3.65/MMBtu and \$5.30/MMBtu.

For deliveries to Europe, the shipping cost is estimated to range from \$0.70/MMBtu to \$0.90/MMBtu, setting the Europe-specific constant B in an equation analogous to Eq. 4.1 within the range \$2.95–\$4.40/MMBtu.

Figure 4.6 shows the notional price of U.S. LNG delivered to Northeast Asia from January 2016 to July 2020 based on average monthly Henry Hub prices and compares it with the average price of LNG imported into Japan based on the monthly data from the country's Ministry of Finance. The average monthly prices of LNG imported into China, South Korea, and Taiwan over the same period were similar to those for Japan. Figure 4.6 also shows the average Japan Korea Marker (JKM) price over the same period.

From February 2016, when LNG production at Sabine Pass commenced, until the end of 2017, the price of U.S. LNG delivered to Japan

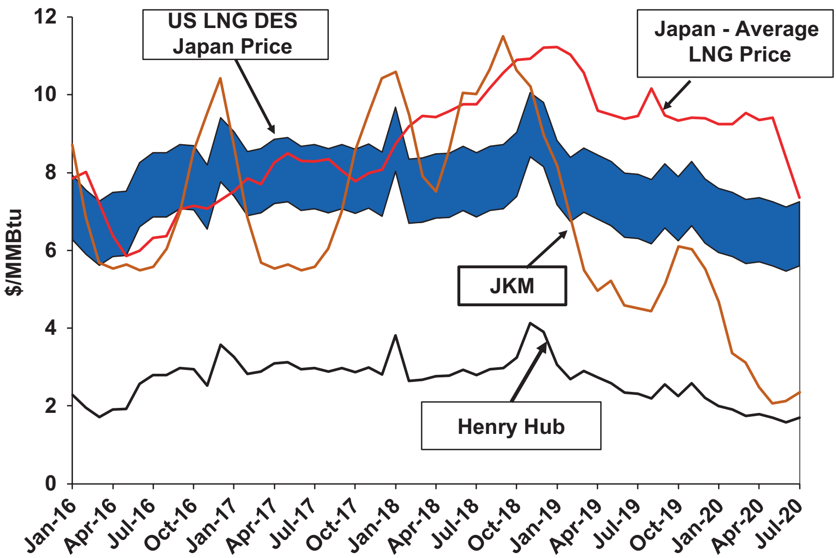

Fig. 4.6 Notional U.S. export price versus average LNG import price in Japan and JKM, January 2016–July 2020. (Source: Japan LNG prices from Ministry of Finance monthly data on LNG imports, JKM from S&P Global Platts, and Henry Hub prices from Enerfax Daily)

was at a similar level to the average price of all the LNG imported into Japan during the same month. However, from the beginning of 2018 until early 2020, the U.S. LNG price was lower than the average price of Japan's LNG imports as crude oil prices strengthened, averaging between \$60 and \$70/bbl. The gap between the price of U.S. and average LNG imports had, however, narrowed by July 2020, as the fall in crude oil prices in March 2020 fed through to oil-indexed LNG prices, which in Asia are typically indexed to crude oil prices with a lag of up to three months.

From early 2016 to the end of 2018, U.S. LNG prices delivered to Asia were generally lower than JKM in the winter months and higher in the summer months. However, JKM has been on a downward trend since early 2019, and the fully built-up price of U.S. LNG delivered to Asia has been at a premium to JKM.

Figure 4.7 compares the notional prices of U.S. LNG delivered to the UK from January 2016 to July 2020 with the United Kingdom (UK) National Balancing Point (NBP) price minus \$0.30/MMBtu (the estimated cost of receiving and regasifying LNG at a UK receiving

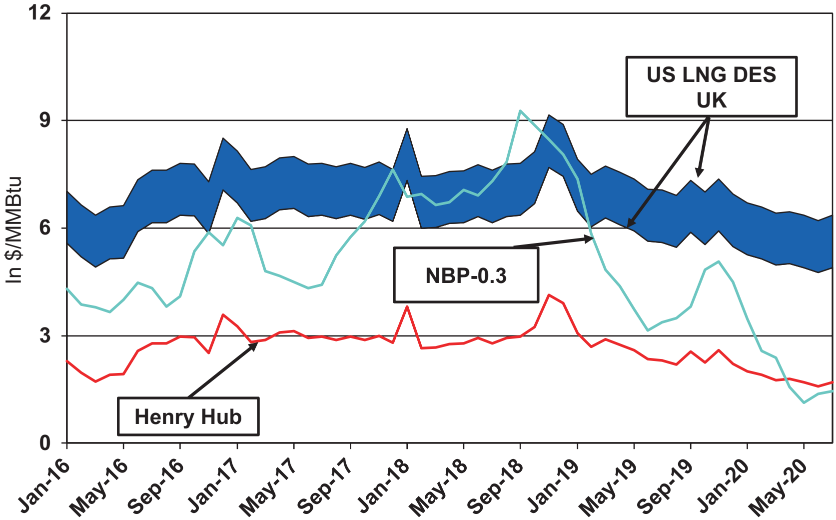

Fig. 4.7 Notional U.S. LNG export prices and UK NBP prices, January 2016–July 2020. (Source: NBP prices from ICIS LNG Daily and Henry Hub prices from Enerfax Daily)

terminal). It shows that the fully built-up cost of U.S. LNG delivered to the UK was higher than NBP minus the regas cost throughout the period except for late 2017 to the beginning of 2019. In May and June 2020, NBP was below the Henry Hub price, so the revenues from delivering U.S. LNG to the UK did not cover the cost of natural gas supplied to a U.S. LNG plant.

U.S. Cargo Cancellations

Low spot prices in Asia and Europe in 2020 left buyers and off-takers of the U.S. with little choice but to cancel cargo liftings under the terms of their long-term SPAs, unless they had contracts to sell cargoes at oil-indexed prices or a price based on the cost of U.S. LNG. Figure 4.8 shows the economics of U.S. LNG for a buyer or off-taker lifting a cargo for delivery to Northeast Asia on a spot basis.

The three solid lines show the fully built-up cost of the cargo, that is

$$P(\mathrm{LNG}) = 1.15 * \mathrm{HH} + \mathrm{liquefactionfee} + \mathrm{shippingcost}$$

at three different liquefaction fees:

- $2.25/MMBtu, Shell's fee for LNG from Sabine Pass (Cheniere's lowest)
- $3/MMBtu, the fee paid by most of the other buyers from Sabine Pass
- $3.50/MMBtu, the fee for LNG from Corpus Christi

The dashed line shows the cost on a short-run marginal cost basis,

$$1.15 * \mathrm{HH} + 0.50$$

Under the terms of long-terms SPAs or tolling agreements, the liquefaction fee is a sunk cost, since it has to be paid even if a cargo is not lifted. The charter rate for the ship is also a sunk cost if the buyer or off-taker has entered into a term charter—an alternative approach in this analysis would be to assume that a ship is chartered on a spot basis, which would increase the marginal costs. If the ship is chartered under a term charter, the marginal shipping cost is the cost of fuel used on the voyage (boil-off gas and any fuel oil or marine diesel) and the port costs at the loading and unloading terminals.

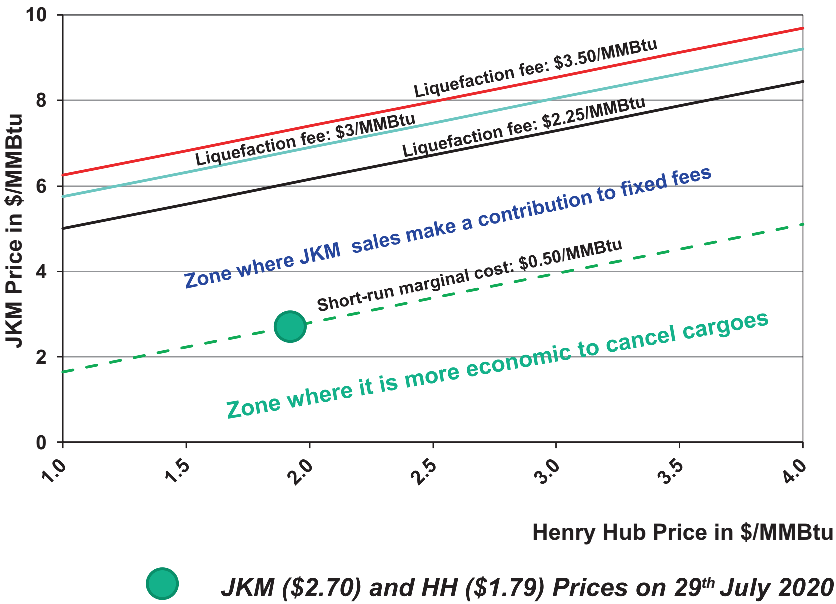

Fig. 4.8 U.S. breakeven economics for LNG sales to Northeast Asia

The vertical axis in Fig. 4.8 is the JKM price that would be needed to cover the costs at Henry Hub prices ranging from $1 to $4/MMBtu. The gap between the short-run marginal cost and the fully built-up cost is the zone where buyers and off-takers would be expected to lift cargoes, since the JKM price covers the marginal costs and makes a contribution to the fixed costs (liquefaction fee and ship charter). Above the solid lines is the zone where the buyer or off-taker makes a profit on the cargo. Below the dotted line is the zone where it is more economical to cancel cargoes since lifting them would add to the losses the buyer or off-taker incurs in paying the liquefaction fee and the ship charter. For much of the second quarter of 2020, JKM and Henry Hub prices put the economics in the zone where it is more economical to cancel cargoes. Figure 4.8 shows that, on July 29, 2020, the marginal costs would just be covered, so a decision on whether or not to cancel a cargo could go either way.

Figure 4.9 shows the same analysis for cargoes for delivery to Northwest Europe. At TTF and Henry Hub prices in 2Q20 and on July 29, 2020,

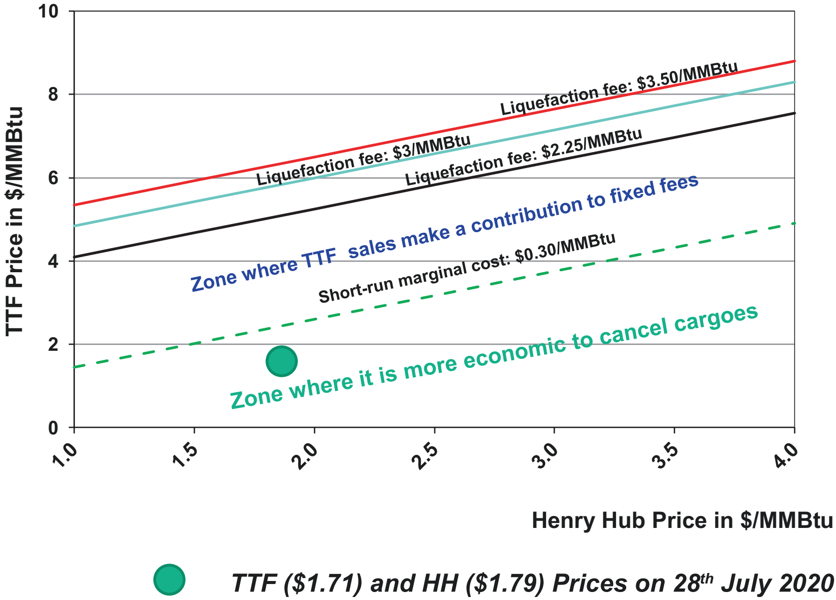

Fig. 4.9 U.S. breakeven economics for LNG sales to Northwest Europe

the decision on whether to cancel was clear with the potential revenues for a sale not covering short-run marginal costs.

Under the terms of Cheniere's contracts, buyers have to give notice of the cancellation of cargoes by the 20th of the month, two months before the month of lifting, that is, a cargo scheduled to be lifted in October 2020 should be cancelled by August 20, 2020. Under tolling contracts, the tollers or off-takers can cancel cargoes closer to the date of lifting.

Buyers, tollers, and producers have been reluctant to give firm details of the numbers of cancellations, so we have to rely on estimates of cancellations from the U.S. Energy Information Administration[39] and other sources[40], which are shown in Table 4.7.

The total volume of LNG cancelled in the 195 cargoes between April and October 2020 is around 12.7 mt. The average liquefaction fee for the cargo loaded onto a 165,000 m^3 ship is \$10–12 million, so the total cost of liquefaction fees for cancelled cargoes over a six-month period is between \$1.3 and \$1.52 billion.

Table 4.7 U.S. cargo cancellations

2Q20	
April	2
May	12
June	46
Total 2Q	*60*
3Q20	
July	50
August	45
September	30
Total 3Q	*125*
4Q20	
October	10
Total to date 4Q	*10*
Total 2020 to date	*195*

The reason for the reduction in the number of cargoes being cancelled in September and October is the strengthening of spot prices with the approach of winter and increased natural gas consumption. On August 28, JKM futures prices were \$3.975/MMBtu for October, \$4.625/MMBtu for November, and \$5.20/MMBtu for December. The Henry Hub futures price for October was \$2.71/MMBtu. In August 2020, a trader would have been able to lock in the JKM price in November or December, agree to lift a cargo in October based on a Henry Hub price of \$2.71/MMBtu (so the cost of gas supplied to the plant would be \$3.12/MMBtu), and lock in the profit by lifting the cargo and delivering it to a buyer in Asia in November or December.

U.S. LNG Exports from February 2016 to July 2020

Exports of LNG from Sabine Pass commenced in February 2016, with Cove Point following in March 2018, Corpus Christi in December 2018, and Elba Island, Freeport, and Cameron in 2019. In 2016, when oil-indexed prices in Asia were low, the main destinations for U.S. LNG were in the Americas. However, as Asian prices strengthened and long-term contracts for Sabine Pass LNG with buyers in South Korea and India came into operation, the share of U.S. LNG delivered to Asia increased (Fig. 4.10).

In 2018, Asia's share of U.S. exports was 53.2%, with 27.4% being delivered to the Americas, 6.4% to the Middle East and North Africa (MENA), and 13% to Europe. However, in the last three months of 2018,

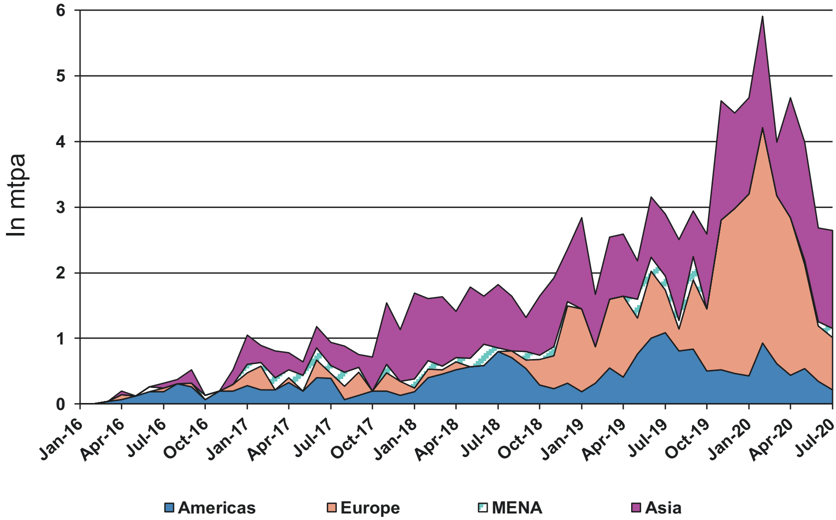

Fig. 4.10 U.S. LNG exports, February 2016–July 2020. (Source: Author's estimates)

the share of U.S. exports delivered to Europe began to increase, and in 2019, Europe replaced Asia as the main destination for U.S. exports, with a share of 38.5% compared with 36.8% being delivered to Asia. In the first 7 months of 2020, the share of U.S. LNG exports going to Europe increased further to 49.9%, with Asia's share at 36.9%. The changing shares of LNG delivered to regional markets demonstrate how the destination flexibility of U.S. LNG is enabling buyers and off-takers to switch cargoes between markets in response to changes in demand and movements in prices.

Competition from Outside the U.S.

The developers of proposed U.S. export projects face strong competition in securing commitments to the planned capacity from developers in other countries seeking to build LNG export plants to monetize stranded natural gas or natural gas surplus to the requirements of the host country. LNG buyers, especially in countries where LNG is the main or only source of natural gas supply, often want to encourage competition among suppliers to avoid overdependence on any one source of supply.

Canada—British Columbia The announcement of plans for an LNG export plant at Kitimat in British Columbia ten years ago was followed by a series of announcements by other developers, and by 2016, about 20 projects had been proposed, with total production capacity of over 250 Mtpa. Natural gas supply was to come from shale gas reserves in the northwest of the province, whose only alternative market was the U.S., where the netback to the wellhead would be at a large discount on Henry Hub prices. The liquefaction plants would be closer to the markets of Asia, reducing shipping costs, compared with competitors on the U.S. Gulf Coast, but their development would require long pipelines across the Rocky Mountains, and the projects faced strong opposition from environmentalists and First Nations concerned about the impact on their traditional hunting and fishing grounds. Most of the developers have given up the challenge and have either abandoned their planned projects or put activity on indefinite hold.

Only the Shell-led LNG Canada project has taken FID. Pacific Oil and Gas, a subsidiary of the Royal Golden Eagle (RGE) group based in Singapore, continues to progress its 2.1 Mtpa Woodfibre LNG project at Squamish, north of Vancouver, but FID has been deferred until 2021. Chevron and Woodside Energy have suspended work on their planned Kitimat LNG project, and Chevron has said it is looking to sell its 50%.

Eastern Canada At one time, five projects had been announced for Eastern Canada, with Europe the main target market. Only one, Pieridae's Goldboro LNG is still being actively pursued. LNG Ltd.'s 8 Mtpa Bearhead LNG project was not part of the deal that saw its Magnolia LNG project acquired by Glenfarne, but the probability of it being developed is low.

Mexico In addition to Sempra Energy's plan to convert its Costa Azul receiving terminal in Baja California into a liquefaction plant, which is discussed earlier, Mexico Pacific LNG is planning a 12 Mtpa LNG at Puerto Libertad in Sonora state on the West Coast. It is controlled by AVAIO, a U.S. infrastructure investment firm which says FID on the first 4 Mtpa is expected in 2021, with the start of production in 2024.

Australia Ambitious plans once existed for Australia to continue the expansion of the country's LNG capacity beyond the seven projects for which developers took FID between 2009 and 2012. These plans included adding new trains at plants in operation and under construction and developing new greenfield projects. As costs escalated, most of those plans were abandoned or put on indefinite hold. The focus now is on developing proven gas reserves to backfill the North West Shelf and Darwin LNG plants as reserves decline in the fields currently supplying the plants. It is possible that the Scarborough field, which Woodside has been planning to develop to supply a second train at Pluto, could supply the North West Shelf plant.

Papua New Guinea The plans to increase capacity by 8.1 Mtpa though the construction of three 2.7 Mtpa trains are on hold, and unless the government and ExxonMobil are able to reach agreement soon on the development of the P'nyang field to supply one of the trains, the expansion could lose out to projects elsewhere in the world.

Indonesia The most recent news on the 9.5 Mtpa Abadi project has been Shell's decision to sell it 35% share of the project[41] as part of the actions it is taking to reduce capital expenditure in response to the Covid-19 pandemic and low oil prices. Inpex, the operator, has said it will continue to develop the project and is targeting production start-up in the late 2020s.[42]

Russia Plans for a third train with a capacity of around 5.5 Mtpa at the operating Sakhalin 2 project were put on hold in November 2019 because of lack of natural gas resources, U.S. sanctions, and Gazprom giving priority to increasing pipeline natural gas supply to China. The decision to put Sakhalin 2 expansion on hold means that the Sakhalin 1 consortium led by ExxonMobil with Russia's Rosneft, India's ONGC Videsh, and Japan's SODECO is now focusing on developing a 6.2 Mtpa LNG plant.

In June 2020, Gazprom signed agreements for the feedgas supply and construction of petrochemicals facilities at its planned integrated petrochemicals and LNG development in the Baltic Sea port of Ust-Luga. There was no mention of the planned 13 Mtpa Baltic LNG plant in Gazprom's announcement of the agreements, which suggests it is seen as a future option rather than a priority.

Novatek has ambitious plans to add more liquefaction capacity in the Arctic in addition to Ob LNG, to develop large-scale reserves discovered in the Yamal region.

Tanzania There appears to have been no progress in discussions between the government and Shell, Equinor, ExxonMobil, Ophir Energy, and Pavilion Energy on "host government agreements" for the development of the LNG project, which restarted in 2019. The project is effectively on hold, with no prospect of production starting before the late 2020s at the earliest.

How Much New Liquefaction Capacity Is Needed to Meet Demand Growth?

A critical issue for companies planning to develop new liquefaction capacity is how much supply from new projects will the global market require, and when. Owners and financiers are generally only prepared to make the funds available for capital-intensive LNG projects if the volume risk is mitigated through long-term commitments to a major share of the proposed output by buyers or off-takers with a strong credit rating. The share of the output that needs to be covered varies among projects, but typically shareholders and financiers are looking for at least a 70% share.

The appetite of buyers and off-takers to make new long-term commitments varies as markets and prices change. According to Shell's 2020 LNG Outlook, commitments were made in aggregate to an average of around 800 Mt per year of LNG supply between 2011 and 2014, including commitments to output from the first wave of U.S. export projects. Some established buyers found themselves overcommitted to supply, and between 2015 and 2017, new contracted volumes averaged only 300 Mt per year. However, the strong growth in LNG demand in 2017 and 2018, led by China, gave more confidence to buyers, and 600 Mt of LNG was contracted in 2018 and around 350 Mt in 2019, supporting the surge in FIDs on new liquefaction capacity between October 2018 and December 2019.

At the beginning of 2020, before Covid-19 was declared a global pandemic, buyers appeared to be prepared to make further new long-term commitments as LNG demand continued to grow. The developers of 200 Mtpa of planned new liquefaction plants lined up to take FID in 2020 in response to what was expected to be a buoyant market. However, Covid-19 has added to the uncertainty over how demand will grow in the countries that currently import LNG and which countries will emerge as importers.

Countries import LNG for many reasons:

- It is the only source of natural gas supply, as in Japan, South Korea, and Taiwan.
- To supplement declining domestic production, as in Thailand, Argentina, Pakistan, and Bangladesh
- To create competition for the dominant supplier of natural gas, as in Poland and Lithuania
- As a cleaner alternative fuel for power generation, as in Jamaica, Colombia, Dominican Republic, and Malta
- To diversify sources of natural gas supply, as in China, India, Singapore, Spain, France, Greece, and Italy
- To move natural gas from remote domestic reserves to centers of population, as in Indonesia and Malaysia
- To meet seasonal natural gas demand, as in northern China, Kuwait, UAE, and Argentina

In Northwest Europe, not only demand drives LNG imports; the terminals in the region also provide a “market of last resort” for LNG producers and sellers who have cargoes surplus to the requirements of other, more-highly valued markets. Consequently, the balance of supply and demand in the global LNG market will have an impact on the level of European imports.

I have developed forecasts of LNG demand under three scenarios for the period to 2035:

Base Demand Case: It is assumed that global economic growth begins to recover in 2021 and reaches the pre-Covid level by the mid-2020s. In Japan, only a small number of the mothballed nuclear plants are brought back into operation, and in the rest of the world, few new nuclear plants are built and older plants are shut down. Renewables continue to grow strongly, but the targets of many governments prove to be over-optimistic. Switching from coal to natural gas in the power and industrial sectors is the main source of natural gas demand growth. New LNG importers around the world are a source of LNG demand growth together with demand from the transport sector (mainly ship bunkers and heavy-duty road vehicles and buses).

High Demand Case: It is assumed that there will be a stronger and more rapid return to growth for the global economy as Covid-19 is brought under control. The use of natural gas will be supported by governments and consumers to reduce air pollution and carbon emissions. Governments will speed up the development of LNG imports by accelerating the permitting of new terminals. The use of LNG in the transport sector will increase more rapidly than in the base case scenario.

Low Demand Case: In this scenario, it is assumed that natural gas will be widely treated as "just another carbon emitting fossil fuel", slowing the growth in demand as the development of renewables increases rapidly. LNG will come under pressure from environmentalists highlighting whole chain carbon and methane emissions.

On the base case, global demand is forecast to increase from 357 mt in 2019 to 475 mt in 2025, 575 mt in 2030, and 610 mt in 2035 (Fig. 4.11). The average annual growth rate is 4.9% from 2019 to 2025, slowing to 3.4% from 2025 to 2030 and 1.2% from 2030 to 2035. The average over the period from 2019 to 2035 is 3.4%, around half the historic growth rate of approximately 7% pa. Asia remains the main market for LNG as demand grows in China and South and Southeast Asia. However, demand

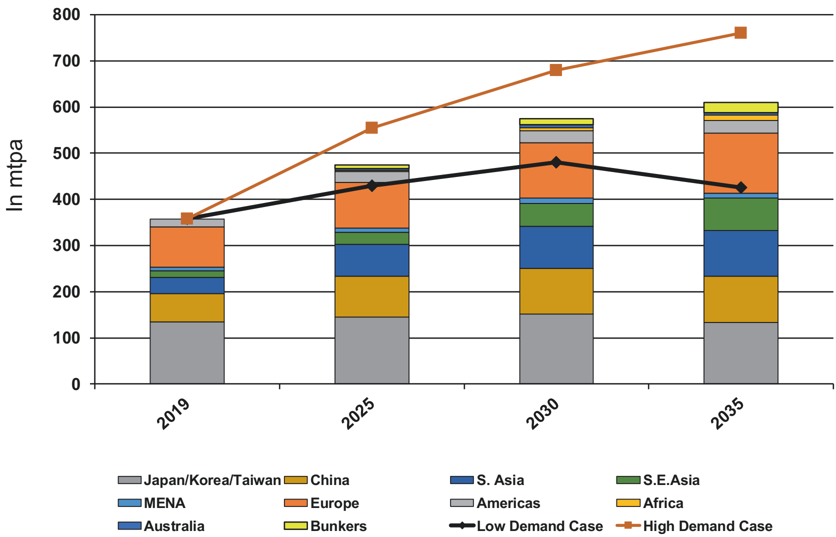

Fig. 4.11 Global LNG demand and supply, 2019–2035. (Source: Author's forecasts)

grows slowly in the established markets of Japan, South Korea, and Taiwan over the period to 2030 and declines over the following five years.

In the high case, demand is forecast to grow to 555 mt in 2025, 680 mt in 2030, and 760 mt in 2035, an average annual growth rate of 4.8% between 2019 and 2035, which is lower than the historic growth rate. In the low case, demand is forecast to increase to 430 mt in 2025, 480 mt in 2030, and decline to 425 mt in 2035.

Figure 4.12 compares the demand cases with the expected production from projects in operation and under construction in August 2020. The gap between supply and demand on the base case is 28 mt in 2025, increasing to 105 mt in 2030 and 170 mt in 2035. In this case, the requirement for output from projects currently at the planning stage only begins to emerge in 2025, which is the earliest significant production from which planned projects could be available, given that few, if any, FIDs are expected in 2020. The requirement for 105 Mtpa of new liquefaction capacity by 2030 is around 50% of the capacity on which developers were targeting FID in 2020, and even in 2035 only 85% of that capacity would be required.

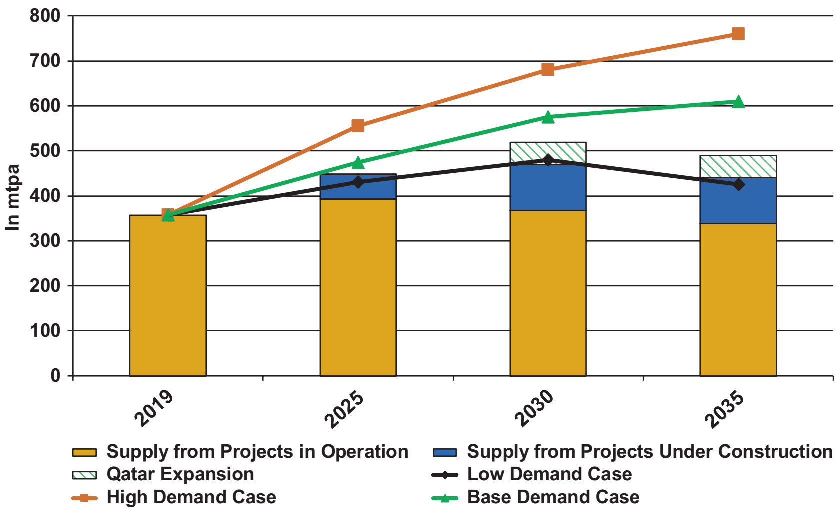

Fig. 4.12 Global LNG supply and demand 2019–2035—with potential Qatar expansion volumes added to supply from projects in operation and under construction in August 2020. (Source: Author's proprietary database)

The low demand case would mean a limited requirement for the output from planned plants, because demand can be largely met by the capacity in operation and under construction in August 2020. The high demand case is one that developers must be hoping for, with 108 Mtpa of new capacity needed by 2025 increasing to 210 Mtpa by 2030 and 320 Mtpa by 2035.

Qatar appears to be determined to go ahead with the construction of a six-train expansion to its current capacity, which will add 49 Mtpa to production by the late 2020s. As Fig. 4.12 shows, the output from these trains would meet around 50% of the additional capacity required in 2030 on the base demand case.

Conclusion: A Challenging Time for the Developers of New Liquefaction Projects

It is often forgotten that the U.S. was the second country to start exporting LNG, with the Kenai project in Alaska sending its first cargo to Japan in October 1969. For most of the next 50 years, it has been an importer rather than an exporter, and twice, in the 1970s and in the early 2000s, it was forecast to become the world's largest importer because domestic natural gas production was expected to be unable to meet the growing demand. The shale gas revolution transformed the domestic natural gas supply and demand balance, and the U.S. is now a major exporter. LNG production built up rapidly after the Sabine Pass plant in Louisiana started up in early 2016. The U.S. now has six plants in operation and two more under construction, and exports are expected to reach over 100 Mtpa by the mid-2020s.

However, the much talked about second wave of U.S. LNG exports stalled as the developers of 176 Mtpa of capacity, which has regulatory approval from the DOE and FERC/MARAD, struggle to secure commitments from LNG buyers and off-takers, who are reluctant to make new long-term commitments in the aftermath of Covid-19, which has increased the uncertainty in the demand for natural gas in downstream power and natural gas markets. Another 69 Mtpa of planned U.S. liquefaction capacity has started the approval process.

Covid-19 reduced the demand for LNG in 2020 because of the lockdowns imposed in many countries around the world to control the spread of the virus. It resulted in the cancellation of nearly 200 U.S. LNG cargoes in 2020 as well as adding to the uncertainty of future demand growth for

LNG. Importantly, as our book went to press, after falling to a pandemic low of about 2.6 Mtpa in July 2020 (Fig. 4.10) U.S. exports surged so that January 2021 volumes exceeded the pre-pandemic peak in January 2020.

LNG demand is expected to return to growth as the pandemic is brought under control and the global economy recovers. When it does, proposed U.S. projects, which account for just over 50% of proposed projects globally, will face strong competition to secure commitments from buyers, who are likely to be more demanding of sellers in the negotiation of new contracts. Buyers and off-takers will seek lower prices that respond to changes in supply and demand in their power and natural gas markets, and they will want increased volume and off-take flexibility.

Developers are looking for ways to reduce costs to position their projects to respond to the requirements of buyers and off-takers and to ensure that their projects are economic in the lower price world that is now forecast as a result of Covid-19 and following the collapse in crude oil prices in 2020. They also need to be able to give buyers and off-takers confidence that their project will be a safe, reliable, and competitive source of supply and that the schedule for the start of production will be met. Relationships will, as always in the LNG business, be important in building the trust between buyer and seller required for the commitment to a long-term sale and purchase agreement.

The most formidable competition for U.S. projects will come from Qatar, which is determined to develop its enormous natural gas reserves and expand its liquefaction capacity by 49 Mtpa. Its costs are amongst the lowest, if not the lowest, in the world; geographically it is midway between the markets of Asia and Europe; it has a track record of safe and reliable supply, and having supplied LNG to most of the world's buyers, it has well-established relationships. Proposed projects in other countries including Russia, Mozambique and Canada want to develop reserves as quickly as possible to minimize the risk of being left with stranded assets if targets for reducing carbon emissions lead to declining demand for natural gas.

Even if LNG demand recovers quickly from the impact of Covid-19 and grows strongly, it is unlikely that there will be a market for all the close to 500 Mtpa of proposed capacity, making it inevitable that many of the projects will eventually be abandoned. The challenge for the developers of planned U.S. capacity is to develop a commercial tool kit that enables them to make a compelling offer to buyers and off-takers in a challenging and competitive global market.

Notes

1. Off-taker contracts with Sabine Pass, Freeport (first two trains), Cameron and Freeport (third train) were signed between 2011 and 2013. FIDs followed between 2012 and 2014.
2. For background on U.S. LNG and export rules, see https://www.energy.gov/fe/science-innovation/oil-gas/liquefied-natural-gas
3. The project that has not formally announced a delay in FID almost certainly will be, given that, at the time of writing, we are near the end of the year, developers only have commitments to 3 Mtpa of the 10 Mtpa of the planned first phase output and they will need to raise finance.
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