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Energy and Climate Report

Afternoon Briefing - Your Preview of Today's News

The following news provides a snapshot of what Bloomberg BNA is working on today. Read the full version of all the stories in the final issue, published each night.

Liquefied Natural Gas Export Plans Face Years of Oversupply

Posted July 18, 2017, 7:01 A.M. ET

By Alan Kovski

Plans for exports of U.S. liquefied natural gas have multiplied as a global supply glut has developed, raising the prospect that some exporters may lose money for several years.

Analysts say the LNG surplus also increases the likelihood that some contracts could be renegotiated, some projects may be delayed long enough to get past the oversupply period, and some plans may never come to fruition at all.

Fast growth in worldwide LNG demand should eliminate the surplus in five or six years, so there can be good reason to delay projects and become part of a "second wave," analysts told Bloomberg BNA. But until then, markets—rather than lawmakers, regulators or activists—will pose obstacles to profitable exports.

"There are certainly going to be regrets," said Kenneth Grant, executive vice president of Compass Lexecon, a subsidiary of FTI Consulting Inc. "Margins are going to be squeezed for years."

Companies in the competition for LNG exports range from Exxon Mobil Corp. and Royal Dutch Shell Plc to relatively small outfits founded over the last decade with private equity backing.

About 70 percent of global LNG is consumed in Asia, where contract prices typically are indexed to spot crude oil prices. Currently that indexing produces Asian spot LNG prices of about $5.50 per million British thermal units (MMBtu). LNG from the U.S. for sale in Asia costs an estimated $8 to $9 per MMBtu, taking into account the costs of the gas, liquefaction, and transportation.

"Buying LNG at these prices is a guarantee of losing money," Fereidun Fesharaki, chairman of consulting company FGE, said while speaking recently at the Center for Strategic and International Studies, a think tank in Washington.

Market Pressures Felt

U.S. LNG is being exported only from the Sabine Pass facility of Cheniere Energy Inc. in Louisiana. The buyers and sellers using the plant are struggling with global prices well below their estimated

costs. GAIL (India) Ltd., one of the buyers, reportedly has been seeking to renegotiate its contract, although neither GAIL nor Cheniere has confirmed the reports.

GAIL, whose majority owner is the government of India, is not a small fish, but so far, Cheniere has indicated it has no intention of renegotiating anything.

The pressure for renegotiations may grow substantially, however, as top LNG traders like Shell see the growing risk of losses within their contract portfolios.

Fesharaki suggested some buyers, especially the national oil companies of some LNG-consuming countries, may walk away from contracts and trigger legal wrangling if they cannot renegotiate terms.

Cheniere, which started exporting in 2016, may be able to pass off most of its market risks to customers, but it has had its own financial strains, losing money in 2016. It turned a profit of $172 million in the first quarter of 2017, but its long-term debt amounted to $24 billion, a high level for such a specialized company with such a short track record in LNG.

Cheniere's contractual customers include GAIL, Shell, Korea Gas Corp., Total S.A., Spanish company Gas Natural Fenosa, and British utility Centrica Plc. Typically the companies will buy the gas and market the LNG themselves, although Cheniere also is willing to sell LNG overseas through its own marketing affiliate, giving it at least some of the market risk that its six big contractual customers take.

Challenge to Find Customers

Most companies planning to build U.S. LNG export plants need customers to sign 20-year contracts to give banks enough assurance of revenues to justify the loans for the projects. Projects currently under construction are proceeding because of 20-year contracts typically signed when LNG prices were much higher than they are now, before the slump in gas and oil prices that started in 2014.

The U.S. projects under construction are "tolling" arrangements, where the owner of the liquefaction plant provides the service but does not try to take an ownership stake in the LNG. Customers take the market risk.

Now, the challenge is to find customers willing to sign such contracts when everyone can see spot prices are not fully covering U.S. LNG costs. Big customers in Japan, South Korea, China and India have been the special prizes.

President Donald Trump has been talking of LNG sales as a way to improve the U.S. trade balances with China and South Korea and a way to provide Europeans with less reliance on Russian-pipelined natural gas. His remarks do not square with the market conditions, however.

Chinese companies are over-contracted, and Asian demand is so oversubscribed that the surplus has been going to Europe, Fesharaki said. LNG spot prices in Europe are lower than Asian prices, again raising the prospect of sales at a loss for the near term.

The glut shifts negotiating leverage to buyers, Grant at Compass Lexecon said. Buyers might ask for such things as shorter contract terms, fixed prices, and unlimited flexibility on shipping destinations, he said.

Looking farther ahead, Grant said LNG trading likely will shift as it matures to more flexibility in contracts and fewer tolling arrangements. "You can see where it's going," he said.

Much More Supply Soon

Six U.S. LNG export projects are under construction, with in-service target dates spread over 2017-2019, according to Energy Information Administration (EIA) data. The great majority of their capacity already is committed to 20-year contracts, typically take-or-pay contracts where the LNG buyer either takes the amount in the contract or pays an alternative fee to the owner of the liquefaction plant.

Global LNG trade has been running at 34.6 billion cubic feet a day (Bcfd) and growing at about 6 percent a year. The six U.S. projects under construction will add about 9.6 Bcfd of export capacity, said Victoria Zaretskaya, an EIA analyst.

That is a very large capacity addition during a period when Australia also will be expanding its exports, the projects helping to assure an expansion of the global market surplus, Zaretskaya said.

Fesharaki, looking at the global growth, said, "Between 2017 and 2020 we are increasing the global supply by 40 percent. [There is] no way we can increase the demand by 40 percent in three years."

Qatar, the world's largest LNG exporter, sent a tremor through the LNG market July 4 when it said it would increase its LNG exports by 30 percent in five to seven years through an expansion of its North Field natural gas production. Qatar Petroleum, with majority stakes in the nation's LNG export operations, has some big partners in those operations, including Exxon Mobil Corp., Royal Dutch Shell, and Total S.A.

The cost of producing natural gas at Qatar's North Field and liquefying it is $2 to $2.50 per MMBtu under current market conditions, Zaretskaya said. Such low-price competition means lower utilization rates should be expected for U.S. export facilities once the extra capacity comes online, she said.

"It's very hard to compete with Qatar."

Looking at the indexing of Asian LNG prices to crude oil, EIA estimates oil prices would have to climb to the $65-$70 range per barrel for U.S. LNG to be competitive in Asian spot markets, Zaretskaya said. Current prices are below $50 for the benchmark crudes West Texas Intermediate and Brent, though it is commonly expected that they will rise over time.

Prospects for Second Wave

Five U.S. LNG export projects have been approved by the Energy Department and the Federal Energy Regulatory Commission but are not yet at the construction stage, in part because they do not all have customers locked up. Other projects have been proposed but not yet approved.

The projects that have yet to see construction and win permits would form the second wave for U.S. LNG export facilities.

Magnolia LNG LLC, planned for the Lake Charles, La., area, is one of the projects approved but awaiting customer contracts and construction. It is a subsidiary of Liquefied Natural Gas Ltd.

The target for Magnolia LNG is to complete customer contract negotiations and reach a final investment decision by the end of 2018, Greg Vesey, CEO of the parent company and the subsidiary, told Bloomberg BNA.

Vesey's timing might allow most of the glut to pass before his LNG export plant goes into operation. It can take four years to build an LNG export plant, he said. If the construction were to start late in 2018, the plant might be completed around the end of 2022. Analysts have been suggesting the glut will fade by about 2023-2024, although their forecasts preceded the Qatar expansion announcement.

Still, there are quite a few developers aiming for a similar window of opportunity.

"I accept that it is tough competition," Vesey said.

Private Equity Prominent

Magnolia LNG, like many of the projects, has private equity as part of its financial backing. Private equity managers have been diving into energy infrastructure projects throughout the U.S. oil and gas sector.

Stonepeak Infrastructure Partners, a private equity firm, is a partner of Magnolia LNG. Such investment managers look to energy infrastructure investments for their relative long-term stability, Vesey said.

Long-term stability is especially valued by pension funds. IFM Investors Pty Ltd., an Australian investment group owned by pension funds, has invested in one of the projects under construction, Freeport LNG, in Texas. Global Infrastructure Partners, a private equity firm, also owns a piece of Freeport LNG.

Cheniere Energy's institutional investors include BlackRock Inc., The Vanguard Group Inc., The Goldman Sachs Group Inc., Carl Icahn, and hedge fund Baupost Group, among others. And Blackstone Group took a big ownership stake in Cheniere's Sabine Pass project through a Cheniere affiliate.

The developers with projects not yet approved will have trouble catching up because they will find that the Federal Energy Regulatory Commission does not hand out approvals easily even when the five-member commission has a quorum for making such decisions, which it does not now, Vesey said. It took almost three years to get Magnolia LNG through FERC.

West Coast Export Plan

Most of the U.S. export plans are for Gulf Coast sites, and two are for the East Coast. One prominent plan, still at an early stage of permitting at FERC, is for the West Coast—the Jordan Cove project that would ship to Asia from Coos Bay, Ore.

Jordan Cove Energy Project L.P., a subsidiary of Canadian energy infrastructure company Veresen Inc., would build the liquefaction plant and a 235-mile pipeline across Oregon from a gas pipeline hub. A basic selling point would be lower shipping costs and less time than sailing from the Gulf Coast through the Panama Canal to Asia.

FERC rejected the Jordan Cove plan in 2016 because the commission did not see customers solidly

lined up to justify pipeline approval. Now the "pre-filing" stage of the permitting process at FERC has been restarted for the project because 50 percent the liquefaction plant capacity and 66 percent of the pipeline capacity have been contracted.

The biggest buyers for Jordan Cove are JERA Co. Inc. and the Japanese trading giant Itochu Corp. JERA represents two Japanese utilities and is the world's largest buyer of LNG. Australian financial company Macquarie Group Ltd. also has contracted for part of the pipeline capacity through its Macquarie Energy LLC energy trading unit.

Much farther north is a Pacific Coast LNG export plant sitting idle and up for sale. The Kenai LNG plant at Nikiski, Alaska, was idled in 2015 by owner ConocoPhillips Co. and has not shipped anything since, though it is available to do so. ConocoPhillips halted its operations because of "market conditions," it said in 2016, after competing sources of LNG from Australia, Indonesia and elsewhere had surged into the Asian market.

Lining Things Up for FERC

Jordan Cove is talking with other potential buyers and intends to have 100 percent of its capacity under contract within a time frame that should make the project acceptable to FERC, company spokesman Michael Hinrichs said.

"We prefer not to have any more curve balls thrown at us," Hinrichs said, alluding to the company executives' surprise when FERC rejected their plan in 2016.

Fesharaki, though skeptical about projects that are not in construction, said the Jordan Cove project "maybe is still doable."

He was more definite about the Golden Pass project in Texas, with partners Exxon Mobil and Qatar Petroleum, a Qatari government-owned company. Golden Pass appears sure to go ahead because its partners have the money and appear determined to make it happen, Fesharaki said.

Grant at Compass Lexicon implied something similar, though he did not single out Golden Pass. He said the best bets would be the proposals that are well-capitalized and can make use of existing infrastructure. That would describe the Exxon Mobil and Qatar venture.

Canadian Projects in the Wings

There also has been a spate of proposals for LNG exports from Canada, but they have stalled in the face of the same problem of global oversupply.

LNG projects are not in construction in Canada now, although environmental cleanup as a first step in site preparation has begun at a British Columbia coastal site.

That is the location of the planned Woodfibre LNG project. It is owned by Pacific Oil & Gas Ltd., part of a Singapore-based group of companies. It is fully permitted, as are several other Canadian plans.

Woodfibre apparently would be the first Canadian LNG export project out of the gate, maybe with a startup as early as 2020, said Mark Pinney, manager of natural gas markets and transportation at the Canadian Association of Petroleum Producers. It would be an integrated operation, the gas bought and sold by Woodfibre-affiliated companies, not a tolling arrangement.

The biggest question is how robust LNG demand will be, Pinney said. The underlying demand growth has been tremendous, but there can be slowdowns, as happened in 2016 in Japan and South Korea, he said.

Like other analysts, Pinney agreed the glut should be over by 2024 or 2025. "Demand is going to catch up," he said.

James Henderson, director of the Natural Gas Program at the Oxford Institute for Energy Studies, put it tartly in an analysis issued in 2016. "The somewhat simplistic assumption that Asian markets would always obligingly provide consistently high LNG demand growth has become questionable," he said.

California Extends Carbon Trading Program Through 2030

Posted July 18, 2017, 8:48 A.M. ET

By Carolyn Whetzel

Legislation extending California's carbon trading program through 2030, squeaked by both state houses late July 17, secured in part by concessions to industry such as banning local agencies from regulating carbon emissions in certain business sectors.

The thin, super-majority votes to pass A.B. 398—28-12 in the Senate and 55-21 in the Assembly—also required passage of a separate bill, A.B. 617, to tackle localized emissions of harmful pollutants. In the end, eight Republicans and several moderate, business-friendly Democrats supported A.B. 398.

In addition to prohibiting local air agencies from regulating the carbon emissions of oil refineries, power plants, cement producers, and other entities in the program, the bill also provides allowance price caps and an exemption of sales and use taxes for electricity producers on certain new equipment and some construction related expenses. A.B. 398 also suspends a fire prevention fee on rural property owners long opposed by Republicans.

State law enacted last year requires California to reduce greenhouse gas emissions 40 percent below 1990 levels by 2030.

Hard-Fought Victory

Passage of A.B. 398 was a hard fought and important victory for Gov. Jerry Brown (D) who pressed lawmakers to preserve the five-year-old program set to expire in 2020.

"Tonight, California stood tall and once again, boldly confronted the existential threat of our time," Brown said in emailed statement. "Republicans and Democrats set aside their differences, came together and took courageous action. That's what good government looks like."

Brown, industry and business groups, and others believe the trading program is a critical, cost-effective tool in achieving the state's ambitious climate goals and maintaining California's role as a global climate leader.

The governor sought the two-thirds votes on A.B. 398 to help insulate the program from future legal challenges.

A.B. 398 continues the basic framework of the existing program, which sets a statewide annual limit on greenhouse gas emissions and requires the largest stationary sources of carbon emissions to the meet declining annual limits. To comply, covered entities must either install emissions controls to reduce emissions or purchase allowances, or permits.

However, the bill means covered entities must make do with fewer carbon offsets—credits for planting trees and reducing methane emissions. The number of available free allowances under the program will shrink overtime.

The companion air quality bill, A.B. 617, required only a simple majority for passage. Clearing the Senate on a 27-13 vote and Assembly 50-24, A.B. 617, boosts maximum penalties for air quality violations, requires state regulators to update the air toxics program, implementation of community plans to reduce emissions of ozone forming emissions and particulate pollution, and best available retrofit control technology at industrial facilities.

The California Business Roundtable, California Chamber of Commerce, California Manufacturers and Technology Association and dozens of other business and industry groups and labor organizations supported A.B. 398 and A.B. 617.

Large environmental groups including the Environmental Defense Fund and Natural Resources Defense Council supported the bills, but environmental justice and community groups lobbied against the bills, saying the concessions, like allowing the continued use of carbon offsets and free allowances, were unacceptable.

Fewer Nuclear Licenses to Force Layoffs at Nuclear Regulator

Posted July 18, 2017, 9:03 A.M. ET

By Rebecca Kern

Up to 20 administrative support workers at the Nuclear Regulatory Commission may lose their jobs as the agency seeks to cut its workforce to help make up for a funding shortfall resulting from fewer licensing applications, an NRC spokesman told Bloomberg BNA July 18.

The agency, which oversees the safety of U.S. nuclear reactors, has provided 120-day notices of a reduction-in-force to select employees in the Office of Administration, the Office of the Chief Human Capital Officer and the Office of Small Business and Civil Rights, according to a staff-wide email sent by NRC Executive Director of Operations Victor McCree July 12.

The agency is trying to reduce the number of employees that would be laid off to less than 20 by Nov. 6 through other measures such as attrition, the spokesman told Bloomberg BNA.

Funded in part by licensing fees, the agency has received fewer applications from companies to build nuclear reactors, which can cost more than $11 billion. They are struggling to compete in the wholesale energy markets against facilities fueled by low-cost natural gas.

The NRC also has limited its external hiring, offered three rounds of buy-outs to employees and has reassigned employees with potentially affected positions to higher priority work, McCree said in the email.

"Despite these actions, the estimated rate of voluntary attrition through the remainder of FY 2017 will not enable us to meet our FY 2018 workload needs," McCree wrote.

The agency worked with the National Treasury Employees Union ahead of the notifications to avoid the involuntary measures, McCree said in the email.

The NRC is also requesting further staff reductions in its fiscal 2018 budget proposal, which would cut 311 full-time-equivalent employees.

For the past several years, Congress has directed the NRC to reduce its budget and workforce due to fewer nuclear operators planning to build new reactors. NRC's budget has been under scrutiny since it increased staff in 2010 due to an expected influx of new reactor applications, which the agency didn't receive because applicants withdrew them for market reasons.

Clean Energy Is Trouncing Oil, Gas and Coal in Trump Era

Posted July 18, 2017, 9:22 A.M. ET

By Joe Ryan, Christopher Martin and Brian Eckhouse

President Donald Trump took office vowing to revive the coal industry's fortunes. So far, the smart money has been on clean energy.

An index of 40 publicly-traded solar companies, wind-turbine component makers and others that benefit from reduced fossil fuel consumption is up 20 percent this year. That's more than double the S&P 500's 9.8 percent gain. And better than the 8.3 percent rise by an index of leading coal companies.

The eco-friendly stock rally—which comes as oil and natural gas-focused shares have dipped—stems from a constellation of factors, including a Nevada law to boost rooftop solar, China's mass-transit policy and optimism that Elon Musk's Tesla Inc. might deliver its Model 3 sedan on time. In short, Trump's pro-fossil fuel agenda hasn't damaged investor support for clean energy.

"Nothing dreadful has happened, and these companies continue to execute," said Jenny Chase, Bloomberg New Energy Finance's lead solar analyst.

As clean-energy stocks climb, investors have pumped more money into wind and solar. U.S. investments totaled $14.7 billion during April, May and June, up 51 percent from the previous quarter to mark the highest level since 2015, according to Bloomberg New Energy Finance. European investments rose 10 percent, to $8.8 billion.

"We are seeing catalysts for these markets driven by the fact that people increasingly realize clean energy is more profitable than conventional energy," said David Richardson, an executive director at Impax Asset Management, which focuses on sustainability and has about $8.7 billion under management, up 32 percent this year.

Solar stocks are performing especially well under Trump. Sunrun Inc., the largest independent U.S. rooftop panel installer, is up 32 percent, closing July 17 at $7.01. That rally has been fueled in part by a Nevada law passed in June to make solar more affordable for the state's homeowners. Nevada gets more sunshine than almost anywhere in the nation, but it's been a dead-zone for solar since

regulators slashed rooftop panel subsidies in 2015. The new legislation largely restored those credits.

Solar manufacturers are rallying, too. First Solar Inc., the largest American panel maker, has gained 33 percent, to $42.72. Average panel prices, which plunged 35 percent last year, have begun to stabilize, falling just 8 percent since December, to 33 cents per watt. The market shift stems from solar developers aggressively stocking up on panels, fearing that a pending federal trade case could lead to tariffs on imported equipment.

"It created some tailwind for the manufacturers," said Sophie Karp, an analyst at Guggenheim Securities.

Some of the biggest clean-energy gainers include fuel cell manufacturers, which use liquid hydrogen to generate electricity through a chemical process that emits only water. While hydrogen-powered engines have been slow to catch on in cars—largely because of a lack of fueling stations—China has been pushing to use the technology in buses.

As Beijing has beefed up investments this year, fuel cell maker Hydrogenics Corp. has nearly doubled, to $8.70. Ballard Power Systems Inc. is up 73 percent, to $2.86.

Electric car maker Tesla is up 50 percent this year as the company has begun limited production of its Model 3 sedan, its cheapest vehicle yet. Musk says he expects production to reach 20,000 cars a month by December.

In the end, some of the clean-energy gains may be fleeting. The trade case that's driving up solar panel prices may ultimately lead to tariffs that analysts warn could slow overall demand. Fuel cell companies have a long history of ephemeral rallies. And Tesla's stock has been slipping since its June 23 peak after a troubling quarterly sales report and ongoing concern about its ability to mass produce. It closed down 2.5 percent July 17, at $319.57.

German Diesel Makers Get Reprieve as Home States Reject Bans

Posted July 18, 2017, 10:13 A.M. ET

By Elisabeth Behrmann and Birgit Jennen

Diesel engines received a reprieve in Germany after the home states of BMW AG, Daimler AG and Audi signaled they'd allow upgrades of older motors instead of supporting driving bans that some cities are pushing to cut air pollution.

The state government of Bavaria—where BMW and Audi are based—said July 18 that it agreed to a voluntary recall with carmakers in an effort to avoid bans of diesel-powered vehicles in its cities, of which Munich is the biggest. Baden-Wuerttemberg, home to Mercedes-Benz parent Daimler, indicated it would be open to a similar solution.

Auto manufacturers have been lobbying against the prohibitions and offered to pay for the fixes, which could affect as many as 13 million vehicles. Weighing in with their own views are state and federal authorities, as well as German courts.

Germany is wrestling over the future of diesel autos, with possible driving bans in some localities clashing with an industry that employs tens of thousands to produce vehicles that use the technology. While states appear willing to strike deals that allow carmakers to upgrade older models, city governments and courts are likely to continue pushing back and seek bans.

Efforts by Munich, where BMW is based, and Daimler's hometown of Stuttgart come as some urban areas fail European Union air-quality standards and local governments worry about the impact of cancer-causing nitrogen oxide—of which diesel cars are a major source—on the health of their residents. The technology has been under fire especially since Volkswagen AG's emissions cheating became public almost two years ago, a scandal that's also enmeshed its Audi luxury-auto brand.

Of several municipalities that have deliberated on introducing restrictions, the northern German city of Hamburg is the only one that has succeeded in prohibiting older diesel cars from certain streets.

In France, the government has gone a step farther, outlining plans two weeks ago to end the sale of gasoline- and diesel-powered vehicles by 2040 in a bid to become a carbon-neutral nation.

Diesel bans threaten to upend an industry already challenged by the costs of developing electric vehicles. BMW Chief Executive Officer Harald Krueger contends the shift to cleaner cars isn't possible without keeping the fuel, which burns more efficiently than gasoline, as part of an interim step before combustion motors are eliminated.

In particular, diesel technology plays a major role in Germany, where the models accounted for about 46 percent of sales last year. It also supports thousands of jobs. At Robert Bosch GmbH, the world's biggest car-parts supplier, about 50,000 positions are linked to diesel, with many more employed at Volkswagen and other auto producers.

With a federal election just over two months away, German Transport Minister Alexander Dobrindt has come out against vehicle bans, saying they're an ineffective tool for reducing pollution. Dobrindt has organized a gathering of government and industry executives on Aug. 2 to consider options for updating older diesels.

Political Solutions

"Driving bans can only be a means of last resort because they limit the mobility of people," Hubertus Heil—general secretary of the Social Democrats, Chancellor Angela Merkel's junior coalition partner—said July 17 in Berlin. "The solution must be to organize mobility in Germany in another way. So it is good that all parties involved sit down together and develop a concept for the future."

Even as politicians get behind car fixes, there's the risk of judicially-ordered restrictions. On Wednesday, Stuttgart's administrative court will hold a public hearing on a complaint seeking to ban all diesel cars from driving into the city, which is Baden-Wuerttemberg's capital. Stuttgart, built in a valley, has for many years failed air pollution tests. In Munich, a court compelled the city in March to prepare diesel bans to bring down levels of nitrogen oxide.

Last year, the federal Transport Ministry prodded manufacturers including VW, Audi and Mercedes-Benz to recall 630,000 cars that pushed the limits of emissions regulations. Industry leaders contend that the 13 million-car estimate for new fixes is too high.

How that would work and who will pay for it will be discussed at the task force meeting on Aug. 2. BMW and Audi said last month more than 50 percent of their diesel cars that meet Euro-5 emissions

standards could be upgraded, and on Tuesday, Bavaria said the carmakers had agreed to bear the cost of the recalls.

"We see good prospects to find a federal solution to upgrade Euro-5 diesel cars," said Michael Rebstock, a BMW spokesman.